Section 3:

This section contains further detail, supporting analysis and evidence on the issues raised in the initial proposals. The section is structured in separate chapters which are aligned to the individual sections in the initial Ofgem's proposals

Chapter Two - Form, Structure and Scope of Price Control

Question 1: Do you think that a wider deadband on the revenue recovery correction mechanism is appropriate in gas distribution?

1. The following provides additional detail in support of our response in section 2.

2.1 Deadband

2. As previously explained in correspondence with Ofgem, in 2006/7 we under recovered our maximum allowed revenue by 4.6% on average across the 4 networks, primarily due to the impact of warm weather. Although the structure of allowed and collected revenue has changed for FY 2007/8, there remains the potential for similar levels of under or over-recovery, as a result of variations in weather. It seems unreasonable that we should be subject to punitive interest rates due to factors outside our control.

3. Consequently, we would therefore support the introduction of a 5% deadband with the current charging arrangements. The attached document (24 April working group follow up action), submitted 09 May, provides evidence to support this assertion.

Correction Mechanism request fc

4. We are currently consulting with shippers on a potential change to the charging methodology which would improve cost reflectivity and also reduce the exposure of revenue to weather. If charging arrangements are changed in due course to reduce the exposure to factors outside the GDNs control then the suggested 5% deadband might subsequently be reduced, to a level closer to that for electricity DNOs.

Chapter Three - Operating expenditure analysis

Question 1: Do you agree with our approach for setting opex allowances and the proposed allowances we have derived using that approach?

Question 2: 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.

Chapter 3 Contents

3.1 Frontier Benchmark

5. The 'cherry-picking' inherent within disaggregated (i.e. activity level) benchmarking is clearly evident with the sense check carried out by Ofgem by means of a top down regression. NGG are pleased that Ofgem have introduced the uplift factor to try to remove this cherry-picking effect and bring the disaggregated benchmarking to a level consistent with the power of the top-down approach.

6. However, we fundamentally disagree in setting opex allowances for GDNs as a whole to the industry frontier. The uplift should reflect the industry upper quartile and as such should be set at 10% on the basis of the Initial Proposals analysis. Our detailed reasoning is set out below:

3.1.1 Inherent Residual Errors

7. In recognition of the residual errors inherent within any regression analysis, past regulatory determinations (including those by Ofgem), when using a frontier benchmark, have always incorporated a glidepath and/or partial closure to benchmark. Specific determinations are highlighted below:

- Ofwat, Periodic Review 2004 – For operating costs Ofwat applied catch-up to the frontier network, but allowed both a 20% gap closure for sewerage for the 10 data points (10% allowance for water due to more data points) to recognise the likely residual error inherent within regression and a glidepath that included only a 60% catch-up by the end of the review period. In looking at capital maintenance costs, Ofwat set certain criteria which resulted in a frontier being used which was not at the company with the lowest costs.

- DPCR4 Final Proposals, 2004 – Ofgem applied catch-up to the upper quartile with no glidepath. However, Ofgem allowed an uplift for those DNOs who were disadvantaged by base regression and uplifted them to an average of three regressions. This served to uplift those DNOs which may have been disadvantaged by mergers (ownership group) or by the interaction between opex and capex.

- Ofwat, Periodic Review 1999 – 60% catch-up to frontier over period.

- DPCR3, 1999 – The frontier was used in the case of Ofgem's DPCR3 determination. This was however, included with a glide path.

- Royal Mail Price and Service quality Review, 2006 – LECG Regression analysis used catch-up to 90% of frontier with 15-20% residual reduction to benchmark.

- Office of the Rail Regulator Access charges review, 2003 – Oxera opex benchmarking regression analysis uses upper quartile.

8. As can be seen in the diagram below, the Initial Proposals are taking a harsh position on all elements of the operating cost determination.

	Benchmark	Real Shift	Gap Closure	Cost to Achieve	Glidepath
Ofwat (1999)	Frontier	1.4%	60%	None	5 years
DPCR3 (1999)	Frontier	0%	75%	None	2 years
Ofwat (2004)	Frontier + 20% 'residual'	0.5%	60%	None	5 years
DPCR4 (2004)	Upper Quartile	1.5%	100%	ERDC 70% Funded	2 years For singletons
GDPCR IP (2007)	Frontier	1.6% pa.	100%	None	None

Table 3.1 – Comparative Regulation determinations

3.1.2 Upper Quartile and / or Glidepath

9. Without any form of gildepath the alternative is to use upper quartile, as was the case in DPCR4, where Ofgem stated that they "used the upper quartile benchmark to set costs for the price control as it is more robust than using a frontier that relies on a single company"[1]. By using the industry frontier, Ofgem are also operating in direct contrast to its own consultants who use the upper quartile as the benchmark throughout its regression analysis. We see no reason for Ofgem discarding this rationale, given that:

a) The frontier network does not take into account the underlying differences in operating environments that can influence different geographical networks. These unidentified factors will, in addition to efficiency gaps, be part of the explanation, not just efficiency for the fact that the regression is not a perfect fit. This will make it impossible for some networks to achieve this target. Regulatory precedent has always included an adjustment to mitigate this error. This point is noted by Ofgem's consultants LECG in benchmarking work completed as part of the 2006 Royal Mail price control review, "… DFA (regression used by Ofgem) take[s] as the default assumption that all cost variations left unexplained by the variables used represent efficiency variations. It is well known that this is an *implausible assumption* and needs some adjustment in order to set realistic cost targets.".[2]

[1] Electricity Distribution Price Control Review: Final Proposals, pg 72
[2] Future efficient costs of Royal Mail's Regulated Mail Activities, Internal Benchmarking Final Conclusions, LECG, 19 January 2006, page 5, footnote 5

b) Gas Distribution has less data points than electricity distribution, water, sewerage, post or rail GDNs should see more allowance for the increased level of uncertainty that is introduced to the analysis by having fewer data points. Ofwat applied this rationale by increasing the residual reduction for sewerage companies (10 data points) to 20% from the 10% residual reduction applied to water companies (22 data points)[3].

c) This is the first time in gas, with one year's track record only and very little capability or experience of the disparate operating models in play, and with, as we understand a failure on the critical emergency standard (in a warm year as well) for the frontier network. There is also evidence that Ofgem could have already created a situation where inappropriate cost allowances are causing important safety standards to decline. In electricity distribution, for example, the DNO which has cut its costs by the most (United Utilities)[4] from 2004/5-2005/6 also has the lowest overall telephone performance[5]. Further, the two DNOs who have managed to reduce costs to the greatest extent fall into the bottom three DNOs for average speed of telephone response[6] and this speed of response is more than twice as long as 11 of the other 12 DNOs. It is not feasible for NGG to reduce costs by performing at this type of telephony performance, given the safety implications and risk to life that slow response to emergency calls would produce.

d) Since privatisation the gas distribution business has delivered a similar level of operating cost efficiency as electricity networks, as seen in Figure 3.1 below. As such this assumption does not represent removal of inefficiency with other utilities.

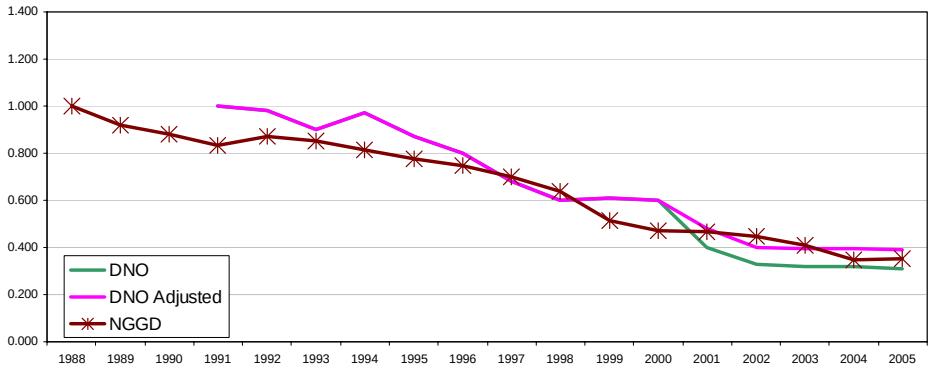


Figure 3.1 – Real unit operating costs for electricity and gas distribution networks

e) Having reviewed the draft consultants' reports, we are concerned that a qualitative assessment of our indirect and direct activities has not been undertaken. There are clearly activities that National Grid undertakes as part of its day to day distribution

[3] Future water and sewerage charges 2005-10: Final determinations, pg 153.
[4] Electricity Distribution Cost Review 2005-2006, Table 2.2, pg 7
[5] 2005/6 Electricity Distribution Quality of Service Report, Table 5.1 pg 12
[6] 2005/6 Electricity Distribution Quality of Service Report, Table 5.2 pg 12

business which deliver benefits to the consumer but are over and above the “least cost GDN” model.

Whilst efficiency is important, cost should not be the sole comparator, particularly where there continues to be a disproportionate reliance on National Grid to provide wider support to the gas distribution industry. It is imperative that this is assessed qualitatively and additional funding provided over and above the “least cost” benchmark. One means by which this could be achieved would be to alter the efficiency gap that National Grid is expected to close in particular areas. Unaltered, the harshness of the Initial Proposals will lead to a reduction in NGG involvement as we streamline our costs to align with the cost of a least cost operating model.

The attached file provides more detail on areas were NGG feel that it provides higher levels of input into aspects of policy development and wider industry development.

3.1.3 Frontier Summary

10. NGG believe that the use of the uplift factor is necessary to remove the cherry-picking effect of bottom-up analysis. The use of the frontier network in doing this, and the inappropriate frontier shift assumptions (see 3.4), result in an unacceptable set of proposals that have no balance between customers and GDN owners with the likelihood of no network achieving.

11. In summary, use of the frontier makes no allowance for noise and given that we understand that the frontier network, NGN, did not achieve the critical emergency standards of service in 2006/7, a year of warm weather. We believe that there is substantial risk that these current proposals will result in and unbalanced incentive that could put safety and security second to striving for an unrealistic frontier.

12. Further given the above points that indicate analysis in gas distribution is likely to be less robust, that a glidepath an appropriate safeguard against setting unrealistic allowances.

3.2 Costs to achieve

13. The Initial Proposals provide no allowance for restructuring costs meaning that those costs necessarily incurred by companies as they seek efficiencies are routinely discounted and achievement of cost of capital even for a frontier network is unfairly restricted.

14. A distinction should be reasonably drawn between efficiency improvements which are needed to reach the 'efficiency frontier' and improvements which are needed to shift the frontier itself. In a competitive market, one would expect the shareholders of a firm which is 'off the pace' to bear the costs of restructuring to compete with the frontier companies. However, frontier companies themselves would normally be able to pass on to customers the costs of staying 'on the pace'. Applied to the GDPCR, this logic would suggest that customers should bear the costs of achieving the frontier shift assumed by Ofgem – including the costs of severance.

15. Precedent on this is mixed. In some reviews, there has been no allowance for 'costs to achieve' efficiency improvement. However, the 1997 MMC review allowed some of Transco's severance costs, there was some allowance for severance in the last NGET control, and in DPCR4 DNOs were allowed 70% of their ERDCs. In addition, it is arguable that not consistently allowing for any severance and related costs in the past was less wrong than it would be in the future. This is because, in the early post-privatisation period, it was clearly the case that most of the privatised network companies were some way from any relevant efficiency frontier. On this basis, it would not have been unreasonable to take the view that costs of efficiency improvement were for shareholders. In addition, the scope for initial efficiency improvement meant that companies could earn healthy rates of return without any explicit allowance for costs to achieve improvement.

16. Neither of these conditions now hold. We believe that the analysis undertaken by Ofgem's consultants is consistent with GDNs being broadly efficient and that, in any event, much of the future cost improvement assumed by Ofgem is explicitly attributed to frontier shift. No one seems to believe that there is a profusion of low hanging fruit (i.e. costless efficiency improvement) waiting to be plucked.

17. On this basis, we believe that the new price controls for gas and electricity transmission should allow for the costs of achieving that part of the assumed ongoing efficiency improvement which is identified with the annual frontier shift for controllable opex.

3.3 Perverse choice of cost driver

18. NGG are very disappointed in the quality of work carried out by both Europe Economics and Ofgem in this area. Europe Economics initially included a completely inappropriate and illogical driver of the percentage of non domestic customers in its top down analysis.

19. Ofgem have continued to utilise a poor composite driver by the use of a composite variable of 50% customer numbers and 50% length of main, supposedly to address the issue of geographical dispersal or network density. The inclusion of network length over compensates Wales and West and inappropriately penalises London network. Density is not a linear factor. Both extremes, sparsity in Wales and the West and high density in London, drive up GDN costs relative to other networks whose density is in between the two extremes.

20. We also acknowledged in our response that a weakness with a single customer number driver is that it would not account for extremes of dispersion, but that this was unlikely to be material with the possible exception of Wales and the West network. Corrupting the strong overall industry fit of customer numbers by introducing an (arbitrary) 50% length driver to resolve what is a single GDN issue does not seem to be a good solution. In fact, it introduces an equal but opposite problem at the other end of the scale, whereby extremely dense networks such as London have their costs underestimated with a length driver – in London's case by a further £2m (in addition to the £3.5m residual London factors such as Congestion Charge and underground ducting that Ofgem are assessing for the September update).

21. Indeed, this is evidenced by the statistical results of moving from a single driver regression based on customer which gives an r^2 of 0.93 compared with 0.87 for Ofgem's composite variable, i.e. introduction of length of pipe has lead to Ofgem using a regression model which fits the data in a less accurate way than if it had used customer numbers alone.

22. Figure 3.2 below, corrects the error in the analysis with regard to the outermet adjustment and atypicals, and demonstrates the loss of fit that is seen in the use of Km. Note, the corrections to the errors does not effect the movement in fit.

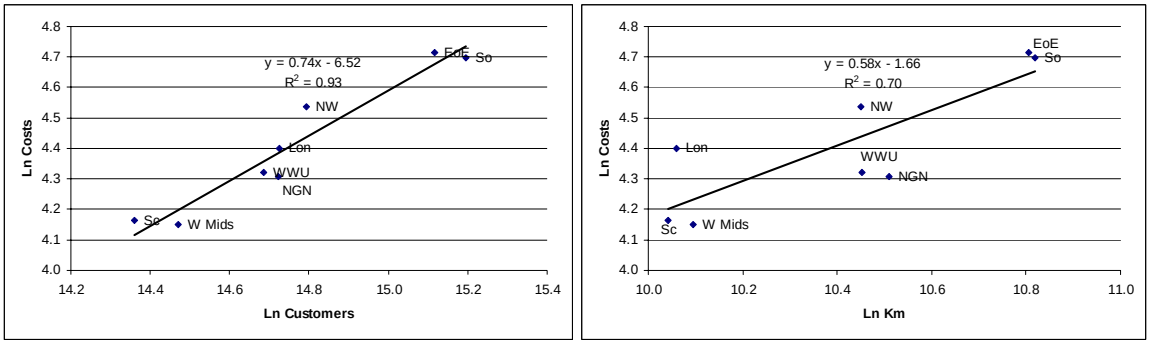


Figure 3.2 – Variation of spread using correct customer numbers and regression Km

23. As illustrated above, customer is the best driver of costs for GDNs. By looking at the GDN cost base, it can be identified that customer numbers is the prime driver for 77% of costs, with 23% being driven by km of pipe.

		Cost driven by		
BPQ Activity	Driver	Customer	Km	Ave rDN £m
Emergency	Customer 100%	9	0	9
Repair	Km 100%	0	11	11
Storage	Customer 100%	2	0	2
LTS	Km 100%	0	3	3
Maintenance other	Customer 100%	8	0	8
Other Direct	Customer 100%	2	0	2
Work management	Customer 75% / Km 25%	14	5	19
Support	Customer 100%	30	0	30
Total		64	19	83
	% Weighting	77%	23%	100%

Table 3.2 – CSV ratio calculated by weighted cost BPQ

24. The rationale for these are:

- Emergency costs are driven by the number of emergency jobs, of which 83% are internal escapes. The number of internal escapes is clearly driven by the number of customers on the network, thus customer numbers drive emergency costs.

- Repair costs are driven by the amount of pipe within a network and therefore the appropriate cost driver is network length.

- Maintenance costs are fairly disparately distributed, but the strongest single driver we can find for maintenance costs is the number of customers. Within Maintenance, storage is driven by level of load, and this is driven by the number of customers, likewise governors within maintenance other are driven by load and therefore customers. LTS is dependent on size of network and therefore driven by network length.

- Work management costs are driven by the emergency, repair and maintenance activities. As explained in 3.9.1, work management costs in effect are driven by both customer numbers and network length of pipe. The breakdown results in a split of 75% customers, 25% network length.

- Ofgems' consultants, LECG, used revenues to benchmark the majority of support services activities. As revenues are directly constructed on the numbers of customers

in a network, it follows that customer numbers are the best driver of support services activities.

25. NGG believe that if Ofgem are to persist with a sub-optimal CSV, then it should at least select a ratio that is based on engineering knowledge, and adopt a CSV of 77% customer, 23% Km. It should also be noted that the inclusion of Km brings the r-sq down to 0.91, below the optimal r-sq of 0.93.

26. This however is not the correct course of action, adding a variable that degrades the fit is not intuitive. During its opex benchmarking completed during the 2003 Access Charges review of the rail industry, Oxera stated "the small dataset (of the 15 stations)…did not enable multiple cost drivers to be considered simultaneously, but only the most significant factor".[7] This supports our response to the 4th Consultation document that the correct approach is to use the single driver with most correlation, i.e. customers. If there are no additional factors that improve the fit, then the appropriate method to account for specific issues, such as London and Wales and West, is by application of evidenced external exogenous factors. 3.10.1 summarises our evidence with respect to the unique London factors.

27. The use of the 50:50 composite driver also highlights the wide disparity between the bottom-up and the top-down benchmarks as seen in the Initial Proposals table A7.2. Ofgem's top-down analysis inappropriately hits London – its difference to bottom-up is 92%, versus South of England which is 119%. Using the results of the regression on customers only (with correction to outermet error) the range of variance between bottom-up and top-down by network reduces from 27% to 13%. This shows that not only is customer a better fit for the top-down data, it is also more accurately aligned with the Ofgem's bottom-up benchmarks.

The revised table is shown below:

£m, 2005/06 prices	Bottom-up benchmark	Top down regression at frontier	% variance to bottom up benchmark
NGG	282.5	309.9	110%
NGN	69.3	73.5	106%
SGN	143.4	160.1	112%
WWU	63.8	71.4	112%
Total	559.2	615.0	110%

Table 3.3 – Revised comparison of top-down and bottom-up approaches

[7] Benchmarking of operating expenditure, Oxera report prepared for Office of the Rail Regulator, July 2003, pg. 22

3.4 Frontier Shift

28. We strongly object to Ofgem's ongoing efficiency assumption of 2.5%pa, particularly as this is derived in part from out-dated total factor productivity (TFP) analysis from Europe Economics. Recent regulatory precedent and empirical evidence both point to a frontier shift nearer to 0% (i.e. net movement in productivity and real prices).

29. Twenty years on since privatisation, with regulated companies driven to concentrate on costs, whereas competitive companies also manage profitability on other factors, it is not appropriate to keep a privatisation effect. NGG are pleased that Ofgem have recognised this and removed it from Europe Economics analysis.

30. However, to assume 2.5% pa productivity from Frontier or Upper Quartile performance is an unsupported and aggressive assumption that is in danger of not allowing any network to deliver against or achieve overall opex allowance.

31. Ofgem have come up with the 2.5%pa assumption by taking the inappropriate and out-dated TFP figure and adding it to a comparative competition assumption (TFP does include element of comparative competition) and too high a capital substitution level. The following points are raised on Ofgem's approach:

3.4.1 Validity of TFP Approach

32. We consider this, to be equally as weak as the privatisation effect in Europe Economics' analysis. There are two main arguments to our position:

a) In both its analysis of relative TFP growth and relative input price inflation, Europe Economics measure expected GDN performance against the wrong 'averages'. Specifically, they mistakenly assume that the rates of TFP growth and input price inflation already captured by RPI are average UK TFP growth and average UK input price inflation, so ignoring completely the contributions coming from goods produced overseas. This error means that the Europe Economics conclusions are wholly misleading.

b) Europe Economics' assertion that the GDNs will out-perform average UK TFP growth is due solely to Europe Economics' assertion that the machinery and equipment, utility, and communications industries provide the best benchmarks for underlying GDN TFP growth. None of these industries are valid comparators:

- The machinery and equipment industry is a capital-intensive sector that bears no resemblance to the labour-intensive engineering services that Europe Economics are seeking to benchmark; and
- Figures for TFP growth in the utility and communications industries are distorted by the 'privatisation effect' affecting the performance of network businesses transferred to the private sector in the 1980s and 1990s. Europe Economics claim that they have stripped out this privatisation effect, but we do not see how this can be true. There is no evidence that the utility industry was out-performing economy-wide TFP growth before privatisation.
- Within a TFP analysis which compares the gas distribution industry to other industries within the UK, which can advantage from a global market, it is essential that the report takes account of the fact that the gas distribution industry can not benefit from globalisation on the same scale as other UK industries in machinery and equipment and communications.

33. The NISEC analysis, which is the basis for this analysis by Europe Economics, only includes data up to 1999. This takes no account of the change in the economy since 1999 (see later section on Europe Economics approach).

34. A further sense-check as to the validity of this TFP analysis can be gained by looking at how much of the growth in the UK economy (GDP) has been driven by productivity improvements. GDP growth is typically between 1.5-3% pa and given that "most of the recent expansion of the UK economy has been driven by increases in inputs rather than by substantial efficiency improvements. TFP growth accounts for only 5% of the UK's GDP growth between 1997 and 2004."[8] This shows that there very little scope for productivity improvements available.

35. Given the above arguments, NGG believe that the 0.6% TFP element of Ofgem's productivity derivation should be excluded.

3.4.2 Capital Substitution

36. In the Initial Proposals Ofgem has set a range by reference to the First Economics review (0.6%) and the low end of the invalidated Europe Economics work (1.2%).

37. The basis upon which Europe Economics derived their range of 1.2% - 1.5% pa has no substantiation to GDN's position. This is supported by the current review of efficiency assessment within the water industry, which includes a review of a replica Europe Economics

[8] UK productivity during the Blair era, Centre for Economic Performance, London School of Economics and Political Science

TFP analysis in which it states that the Europe Economics analysis "requires imperfect assumptions on the historical rates of capital substitution"[9].

3.4.2.1 Capital Substitution Factor should exclude repex influence

38. NGG believe that the true level of capital substitution is in fact 0.5% pa. A fuller explanation is given later in this section, but briefly the value is as low as 0.5% because:

a) Capital investment will have a limited impact on opex of only 0.3% pa. This is due to the fact that the majority of capex is on mandatory customer/gas volume growth related expenditure which does not deliver any capital substitution effect – indeed can increase costs marginally. Efficiencies will however arise from:

- The impact of lower maintenance work flowing from system renewals of old kit for which new equipment/systems will tend to be more efficient.
- Limited impact of IS investment, given the capital investment is primarily about asset renewal, not NPV projects. This current period has seen installation of state of the art electronic systems in back-office, front office (new operators) and field force (all GDNs) over the current period – it should be remembered that this effect is applied to upper quartile/frontier performance and is not specific to NGG (NGG's investment in new back-office system will enable closure of indirect gaps).

b) The mains replacement programme will have an impact of 0.2% pa on opex, based on a 1.25% net reduction in repair workload (see arguments in 3.9.2 of this answer)

39. Whatever the arguments on the impact of repex on repair workload, be it 3% or 1.25%, the mains replacement impact is in fact a double count. This is because:

- Although not explicitly stating, one can take the mid point of the range, i.e. 0.9%, to be made up from the 3% repex impact on repair workload, which equates to 0.6% capital substitution.
- Ofgem are then applying this percentage to all bottom-up activities.
- PB Power has however already applied a 3% pa reduction in the repair workload volumes

40. Given the above, the capital substitution factor in Ofgem's derivation of the productivity assumption should be reduced from the mid-point of 0.9% pa to the capital investment impact only of 0.3%pa.

[9] Review of the approach to efficiency assessment in the regulation of the UK water industry, UK Water Industry Research, pg.129

41. NGG would also point out the differential in the GDN capital allowances in the Initial Proposals may result in more differential between networks than their averaging approach, as higher levels of system renewal will create higher capital substitution.

3.4.2.2 NGG Capital Substitution Derivation

42. The scale of investment activities in GDNs (e.g. £650m per DN over the 5 year period 2008/9 to 2012/13 for our networks) means they are open to an initial challenge of scope for improving productivity through capital substitution. However, some simple analysis of the nature of the investment quickly strips away a lot of this scope.

43. HSE policy driven mains replacement is now the biggest single item of investment spend i.e. replacing iron mains within 30 metres of buildings, typically with PE mains, over a 30 year period. While gradually reducing the numbers of leaks that we have to attend, the primary driver is public safety. The mains replacement programme will deliver 1.25% annual reduction in the number of repairs and a slight reduction in the shrinkage factor. Given that the productivity factor is applied to opex excluding shrinkage, only the impact on repair workload should be factored in, at around £0.9m pa.

In round terms, then:

NGG (4 Networks)	£m
Net investment (capex and repex)	2,575
Of which replacement (largely HSE policy work)	(1,885)
Capex	690
Of which growth (mandatory)	(310)
Balance (renewals)	380

Table 3.4 - Investment breakdown

44. All this renewal capex in our plan is justified on either a technical / physical obsolescence or risk of failure basis. The breakdown over the five years is as follows:

NGG (4 Networks)	£m	Comment
Major plant renewal	113	Mainly gasholder modification, preheaters, governors – minimal opex savings
Other plant renewal or enhancement	56	Tooling, valves, site security, pressure management – minimal opex savings
IS	110	Largely like-for-like replacement – limited opex savings
xoserve	25	UK Link renewal – marginal savings
System control	17	Like-for-like replacement (mainly GTMS)
Vehicles	42	Maintain capacity of fleet – marginal saving
Support	17	Mainly property and stores
Total renewals	380	

Table 3.5 - Renewals investment

45. As indicated, little of this investment is specifically designed to deliver opex savings but is required to reduce risk (e.g. governors), maintain security of supply (e.g. preheaters), comply with legislation (e.g. working at heights) and ensure continued efficient business operation (e.g. system replacement). Clearly, new equipment/systems tend to be more efficient than those replaced but equally deteriorate over time such that over a 5-year period we estimate the net benefit to opex to be small. IS opex costs are expected to fall by around £1m a year for NGG's four networks. It must however be recognised that NGG IS forecasts already have this capital substitution effect built into them and our plans impact on the upper quartile benchmark, then this effect is a duplication when applying productivity to the benchmark allowances for all networks. As such this effect on IS opex costs should be excluded.

46. It should also be noted that this investment will help drive costs down to the benchmark level. This is an example of investment strategy differences influencing opex spend, as NGG does not have the advantage of other sold networks who have built new back-office systems.

47. Other opex benefits from our investment programme are likely to be of a similar magnitude, reflecting a combination of reduced maintenance costs achieved through increased renewal and refurbishment (£0.5m) and other people-based savings from system developments (£0.5m).

48. Combining the above with the impact of the mains replacement programme, we estimate that overall opex savings as a result of investment could be in the range of £1.9m a year (i.e. around 0.5% of our cost base).

49. It should be noted that NGG is forecasting additional opex (compared with the previous 5 years) reflecting cyclical major maintenance and refurbishment of some assets (e.g. holder and AGI painting, holder repairs). Without this opex spend, these assets would deteriorate and would ultimately require replacement. In the case of gas holders, the replacement storage would typically be delivered through pipelines which, if specifically built for storage, could be significantly more expensive.

50. An alternative angle on this is to look at the maturity and nature of the activities undertaken by GDNs. Basically where technology is relevant, it is a very mature field (i.e. "in the trench" techniques to repair or install assets). Most of the rest is people based, either directly employed or purchased from the contractor market.

51. The other defining characteristic of gas distribution is the influence that risk management and compliance has, driven by the basic nature of the activity of pumping explosive gas, at pressure, into 20million homes using (sometimes) Victorian pipes! In business terms, this again means GDNs simply have little choice about most of their key outputs, be they

engineering, safety or service based. For example, irrespective of efficiency initiatives, a fixed number of field staff is required in order to meet our Licence obligations on emergency standards of service (where the obligation is to attend an uncontrolled escape anytime, anywhere, within one hour of it being reported). It is not possible to further automate these processes to achieve large scale productivity gains (short of helicopters!) given the level of cover required at all times.

3.4.2.3 Effect of different investment strategies

52. Having established that GDN customers should expect some level of operating cost savings over time because of capital substitution, it is worth considering whether long-term differences in investment levels between GDNs should point towards different levels of operating cost across different networks. This is obviously relevant under a comparative cost assessment regime, and particularly relevant at this stage of GDPCR, where a) investment levels are up to twice that of our networks and b) there is a need for some cross-check work on exactly what the higher levels of capex are and the consequential differential to the operating cost allowances (as outlined already in our section 1 of our response).

53. By way of example, the simple analysis below takes 15 years of DN investment (10 years historic actuals and 5 years' allowances from Initial Proposals, (see 3.7.1 of our response) and uses this to weight the 0.3% average capital substitution between NGG and other networks. The results show that, over 15 years, based on this high level assumption about the effect of capital substitution on operating cost levels, that it could be expected that NGG network's opex is 2.1% higher, all other things being equal, to networks that experience 60% higher levels of investment over a 15 year period. While high level, NGG consider this further evidence in support of our claim that the differential investment strategies require differential treatment in opex.

	Capex spend (15 years)	15 year capital substitution
NGG	38%	0.23%
Sold networks	62%	0.37%
Total	**100%**	**0.30%**

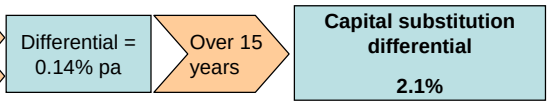


Figure 3.3 - Capital substitution differential

54. As way of example, NGG's Storage strategy is to utilise existing low pressure gasholders rather than build, more expensive, LTS pipelines. This strategy, whilst the most efficient, does require higher levels of opex. Ofgem's use of bottom up analysis to set Storage allowances ignores GDN differences and consequently the additional opex required to fund our strategy has not be allowed.

55. Given the differential in capex NGG stress the need for further work to be carried our to identify the higher allowable costs for NGG, in

- Benchmarking of maintenance, the need to consider both the benchmark differentials which will have lower unit cost of maintenance costs for networks with a greater proportion of new kit, and the level of future maintenance plans, see 3.9.3, and,
- In terms of differentials in the repair workload reduction assumption, where different investment opportunities in pressure elevation will lead to different annual repair workload reductions, see 3.9.2.

3.4.3 Comparative Competition effect

56. NGG accept Ofgem's assumption of a 1.1% pa outperformance above UK productivity improvement as the effect of the new comparative regime that GDNs now operate. This is driven by the fact that the introduction of comparative regulation will continually drive GDNs for efficiency savings in order to benefit consumers both in the current and future periods. However, we do not accept that the 1.1% figure currently assumed in the proposals is compatible with a benchmark set at frontier levels.

57. However, given that the comparative competition effect is a valid assumption, this inherently means that the methodology used by Europe Economics to produce the -0.6% TFP benchmark is flawed. Europe Economics have selected comparator industries for the nature of work benchmark for a GDN, and each one of these comparator industries e.g. construction and business services, already faces the effects of comparative competition. Therefore it is wholly inappropriate to include a further comparative competition effect as this is already in-built with the Europe Economics -0.6% benchmark.

58. The comparative competition effect and the Europe Economics TFP benchmark, can not be used simultaneously and as such this provides a further justification for the Update Proposals not to include the TFP factor.

59. In accepting the assumption on comparative competition effect NGG would however make the following points:

a) Customers are also benefiting from gap closure of comparative regulation and that this assumption is capturing network sale benefits earlier. This in itself is delivering more that the Network Sale Final Regulatory Impact Assessment identified savings. The LECG

benchmarking of indirect costs identifies more than this for NGG networks alone, as illustrated below:

Identified benefits	£225m
Of which driven by	
comparative regulation (95%)[10]	£214m
30% this period	=> £64m
	=> £13m pa

Table 3.6 – competition benefits

b) Ofgem state that "It is unlikely that many of the likely benefits of comparative regulation will be passed through to customers within the first full regulatory period."[11] (2008/9-20012/13). NGG believe that these Initial Proposals do in fact give the anticipated incremental benefits from both the comparative benchmarking and the inclusion of the competition effect in deriving frontier movement

60. As such the 1.1% comparative competition effect is an aggressive assumption, and one that is seeking to ensure deliver of network sale benefits to customers.

3.4.4 Overall Frontier Shift

61. The above arguments, in 3.1 to 3.3 when taken together and added to the inappropriate low level of real price increases (3.5) indicate that the overall movement in frontier shift from productivity and real prices is around 0% or possibly upward, i.e. Table A7.7 of the Initial proposals should read:

TFP outperformance	0%
Privatisation effect	0%
Comparative regulation	-1.1%
Capital substitution	-0.3%
Total ongoing productivity	-1.4%
Real price effect	1.5% to 1.9%
Net cost change pa	**+0.7% to +0.1%**

Table 3.7 – Net cost change

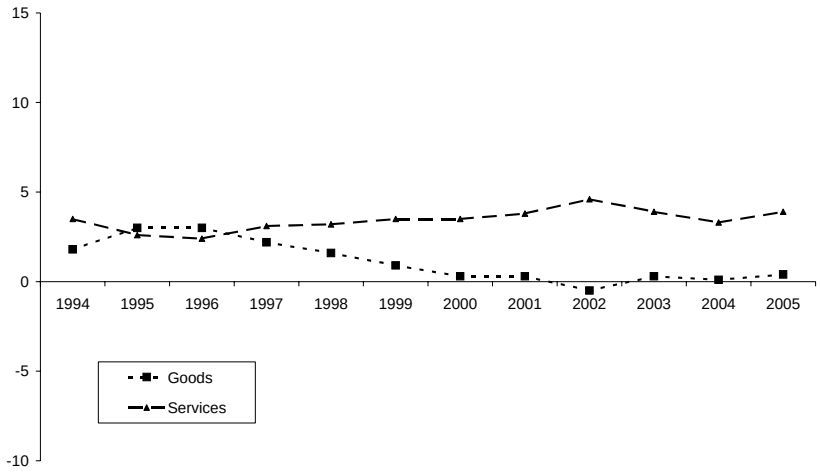
[10] National Grid Transco – Potential sale of gas distribution networks businesses, Final Regulatory Impact Assessment, Summary (page 7)
[11] National Grid Transco – Potential sale of gas distribution networks businesses, Final Regulatory Impact Assessment, 8.29

3.4.5 First Economics Approach

62. The conclusion above is consistent with the conclusions of the First Economics approach which does not separate elements of TFP growth and input price inflation and does not therefore require Ofgem to make assumptions about the rates of TFP growth and input price inflation already captured by RPI. This work identified a range for the net cost change of +0.5% to 0% pa.

63. The work looked at basket of goods which constitute RPI. However this basket does not represent the costs of a GDN. Since 1997 the UK economy has seen a divergence of annual price changes in the goods sector compared to the services sector. Prices in the services sector have increased at 4% per annum since 2000, whereas prices in the goods sector over the same period have been flat. As a GDNs costs are more reflective of the costs borne by firms which operate within the service sector than those involved in the production of goods, a GDN has seen cost increases considerably above the RPI benchmark.

64. A major reason for the emergence of a 'twin-track' economy in the UK is the access firms within the goods sector have to cheaper foreign labour and more productive working methods than in the UK. A GDN is restricted in its ability to benefit from this trend due to the commitment of GDN's to the Safety Case. The trend of annual price changes within the UK economy is shown below:



Source: ONS (2006), 'Focus on Consumer Prices' and First Economics' calculations.

Figure 3.4 – Annual price changes in the good and service sectors, 1993 to 2005

65. GDNs are also disadvantaged vis-à-vis other firms operating in the service sector as the majority of firms operating in the services sector have scope for growth and can achieve productivity improvements through associated economies of scale. Therefore, due to a lack of forecast growth within gas distribution, a GDN is further disadvantaged in its scope to achieve

productivity improvements. Conversely, NGG is facing 'negative growth' impacts due to the reduction in workload because of increased competition in the competitive metering market.

66. We acknowledge that in their benchmarking First Economics make a series of subjective judgments when choosing which components of RPI to include and exclude from their comparator indices. We would not expect Ofgem to agree with every single choice. However, we do not believe that First Economics exhibit any systematic bias in their judgments.

67. We also note Ofgem's comments on the suitability of elements of First Economics' bottom up benchmarking (e.g. entertainment and other recreation). However, if one removes the components that Ofgem has queried, the benchmark results are still in the range 1.4% – 2.1%, and thus are still supportive of a 0% frontier shift. You can also easily challenge that 'energy' should be included, which would in fact increase the results.

68. If Ofgem is uneasy about the composition of First Economics' indices, we would encourage Ofgem to repeat the analysis using comparators of its own. We believe that it is impossible to construct a reasonable comparator to the GDNs that exhibits price/cost trends that move on anything but a substantially above-RPI trend.

69. This is because RPI aggregates and averages two quite different trends affecting the products purchased by UK households: below-RPI cost increases in the goods sector and above-RPI cost increases in the service sector. Since the factors that are contributing to below-RPI inflation in the goods sector – most notably globalisation – are of no relevance to a GDN, it is entirely logical that Ofgem should find that comparator firms are seeing costs move on an above-RPI trend. This, in turn, implies that there is above-RPI frontier shift in network businesses.

70. Further, NGG also note that although Ofgem stated some reservations on the First Economics bottom up RPI basket composition, Ofgem provide no evidence to challenge the First Economics top-down basket which provides the upper bound of the benchmarking results of 2.1%.

71. Given the serious flaws in the Europe Economics analysis, we believe Ofgem should rely on the alternative framework put forward by the GDNs and First Economics which does not separate TFP growth and input price inflation and does not therefore require Ofgem to make assumptions about the rates of these within RPI. It would not be appropriate to use this approach as a cross-check on the Europe Economics methodology as, put simply, the First Economics work is the right way of looking at frontier shift and the Europe Economics work is flawed and wrong. They are not complementary pieces of evidence.

3.4.6 Regulatory Precedent

72. Both OFWAT and the CAA have recently acknowledged that frontier shifts should be in the region of zero in recent determinations / proposals.

73. In the Airports price control review – The Initial Proposals for Heathrow, Gatwick and Stansted (December 2006), the Civil Aviation Authority (CAA) recognised that "there is a question as to why BAA should necessarily be expected to be able to outperform an RPI-based benchmark that – at least historically – appears to be increasingly driven by goods (such as food, new motor vehicles and clothing) whose cost drivers are not directly linked to its own"[12] and ultimately lead to the CAA proposing a frontier shift of zero.

74. In the "Future water and sewerage charges 2005-10: Final determinations", OFWAT proposed a frontier shift of 0.3% for water[13], rejecting work from Europe Economics suggesting a much higher value.

3.4.7 Empirical evidence of 0% frontier shift

75. In DPCR4, Ofgem set allowances for electricity DNOs for the period 2005/6 – 2009/10. In the first year of the period DNO's costs have remained flat (i.e. frontier shift of 0%). NGG also note that the electricity distribution industry has overspent their allowances by 5%.

76. A more detailed analysis of the movements in DNO's costs from 2004/5 to 2005/6 shows that it is only the DNOs who were found to be very inefficient i.e. around the worst quartile that have managed to cut costs between 2004/5 and 2005/6. These DNOs have cut costs by 17% on average. The DNOs who were found to be most efficient have not been able to reduce costs in 2005/6, conversely they have seen an average cost increase of 6%. This shows that although Ofgem's analysis in DPCR4 may have correctly identified those DNOs which had most scope for cost reduction (i.e. largest catch-up) there is no evidence to support an annual efficiency incentive greater than zero i.e. that there is no scope for frontier shift above and beyond any catch-up. Table 3.8 highlights the point.

[12] Price control review - Initial proposals for Heathrow, Gatwick and Stansted December 2006, 12.10, pg 102.
[13] Future water and sewerage charges 2005-10: Final determinations, pg 148.

	2004/05 Actual	2005/06 Actual	Variance	%	Ranking
Better than Upper Quartile					
SSE Southern	53	56	-3.0	-6%	8
CE NEDL	35	37	-2.0	-6%	9
	88	93	-5.0	-6%	
Median to Upper Quartile					
CN Est	57	64	-7.0	-12%	13
SSE Hydro	27	30	-3.0	-11%	12
WPD S Wales	28	31	-3.0	-11%	11
CE YEDL	46	44	2.0	4%	4
SP Distribution	48	53	-5.0	-10%	10
	206	222	-16.0	-8%	
Lower Quartile to Median					
CN West	56	56	0.0	0%	6
WPD S West	40	47	-7.0	-18%	14
EDFE EPN	77	76	1.0	1%	5
SP Manweb	54	54	0.0	0%	6
	227	233	-6.0	-3%	
Worse than Lower Quartile					
UU	66	49	17.0	26%	1
EDFE LPN	50	43	7.0	14%	2
EDFE SPN	59	53	6.0	10%	3
	175	145	30.0	17%	
	696	693	3.0	0%	

Table 3.8 – DNO 2004/5 – 2005/6 cost increases by efficiency group

77. The First Economics analysis into GDN productivity also comprehensively highlights that in the last 5 – 7 years industries comparable to Gas Distribution have seen flat, if not rising costs. This includes Electricity Distribution, cost per passenger at Heathrow and Gatwick airport and in the water industry.

3.4.8 Historic Performance

78. NGG has reduced domestic customer prices by over 30% in real terms over the last 10 years. Now, post network sales, further restructuring and economies through growth in the market are no longer available, as they were in the past. In the past, NGG has achieved opex savings through numerous reorganisations reducing from 90 districts to 32 districts, to 13 LDZs to 8 networks, to one big network, in order to meet extremely stretching opex reduction targets.

79. Since network sale, our *Way Ahead* transformation has concluded the final stage of restructuring, which has put in place a highly centralised organisation. It has a strong shape for the future, but very limited scope for further radical change. Consequently the majority of efficiencies have been driven out of the business (including a 25% reduction in manpower) and future productivity improvements can only be achieved through continuous improvement.

This is summarised in the table below:

	Available to NGG	
Efficiency Improvement Tool	**Past**	**Future**
Re-structuring	✓	×
Scale economies through growth	✓	×
Technical / continuous improvement	✓	✓
Growth	×	×
Benefits of globalisation	×	×

Table 3.9 – Efficiency improvement tool available to NGG

80. Our historical performance has also to be considered over the longer period since privatisation where the gas distribution business has delivered a similar level of operating cost efficiency as electricity networks, of around 6% per annum. The trend in the last few year's is indicating that not only is the privatisation effect over (acknowledged by Ofgem in the Initial Proposals through the removal of this factor from Europe Economics analysis) but also that the recent trend in electricity is flat.

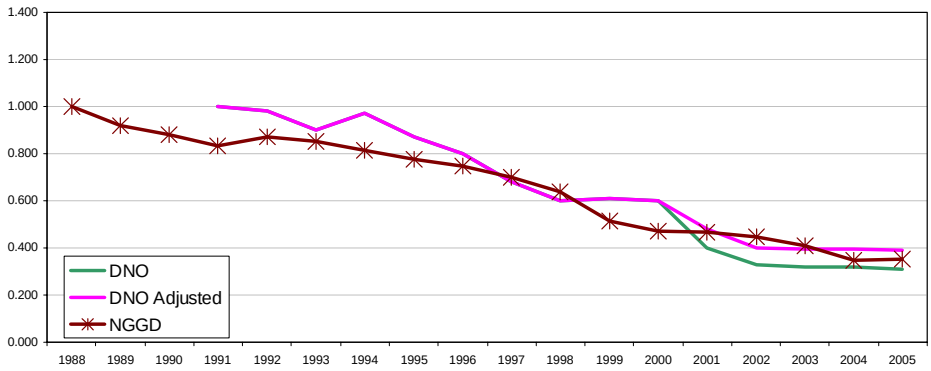


Figure 3.5 – Real unit operating costs for electricity and gas distribution networks

81. As such, to assume a productivity assumption of 2.5% pa from an upper quartile level of performance is an aggressive assumption, being above the long run rate for the UK, i.e. from average benchmark. Therefore, without specific identified opportunities, and for a sector that does not have any growth element to drive productivity, this provides an unfair balance of incentives between upper quartile GDNs and customers.

3.4.9 Restrictions to Future Efficiency Savings

82. Ofgem's blanket 2.5% pa target has been applied to all activities, except insurance. This is an unreasonable assumption given the nature of GDN's operating environment and current

operating practices. For example, evidence has been provided in response to PB Power's questions that demonstrate areas where staffing levels are now at a minimum level necessary to deliver the 24/7 emergency service standards. Ofgem have not considered this in their blanket assumption, indeed they have overridden PB Power's own assumptions on productivity.

83. Our licence conditions require us to provide emergency support to other DNs and the NTS, and ensure the distribution system is able to meet present and future demand. This creates a level of fixed cost. As illustrated in Figure 3.6, this and other factors present GDNs with nearly 40% fixed costs.

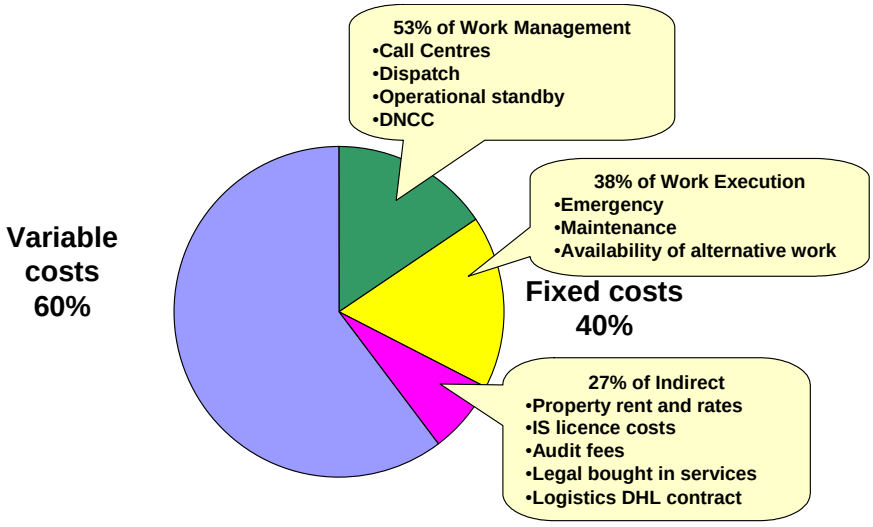


Figure 3.6 – Fixed / variable assumptions

84. Taking these fixed costs into account, this would set an unachievable (from frontier/upper quartile performance levels) of around 4.2% pa. This is discussed in more detail in the document below:

Fixed Costs.doc

85. Indeed, our emergency and repair activities are physically demanding and with 46% of our field force over 45 years old, not only will productivity decline but levels of absence increase impacting negatively on customer service. This will be a big blocker in achievement of future productivity that Ofgem must recognise. NGG, through its price control submission, has sought funding to facilitate the entry of new recruits to assist in delivering productivity improvements – see 3.10.5.

3.4.10 PB Power Assessment / NGG Forecast

86. PB Power's review of scope for productivity in direct costs looked at the general historical productivity levels in the UK of 1.7% to 2% pa. from which they:

- Took a 'conservative' assumption that base productivity of 1% pa for all direct activities.
- Used their engineering judgement to apply an uplift where they believed there was scope for additional productivity. In opex, PB Power only considered that there was more scope in the work management activity, where they included additional productivity flowing from IS investment.

87. We believe that this 'conservative' baseline is an appropriate level given consideration that GDNs do not have the benefit of growth as in the UK economy and that they were applying the productivity to an upper quartile performance not an average as is the UK figure.

88. We however take issue with the IS productivity analysis which mis-understood the IS investment, including not recognising the fact that largely investment was against asset renewal. As such the productivity, including the base assumption, appropriate to work management would be less than 1.3% pa.

89. In our BPQ plan submission, NGG had a range of productivity assumptions ranging from a high level on cost efficiency in IS (4% CAGR), to specific benefits in Finance/HR following our IS investment and for ongoing work 1% continuous improvement in our field workforce. As such our plans have significant productivity built in.

90. It has been pointed out to us that we have a productivity of 2%pa in our plans which can be seen in figure 1 of our 4th consultation response. We would however point out that:

- In part this productivity was targeted at driving out known inefficiencies in our support costs, i.e. not from an upper quartile performance level.
- This included the benefit of productivity in our field force flowing from taking pro-active action on the workforce cliff face that will hit the industry in the period following the next if no action is taken. Without this corrective action, as Ofgem currently have excluded the costs associated with this[14], our productivity assumption will not be achieved in this area.

91. As such our plans do not in anyway back up Ofgem's 2.5% pa productivity assumption from an upper quartile, let alone, frontier performance level.

[14] The IP currently disallows expenditure required to facilitate this initiative, but it may be subject to a separate IFI type treatment.

3.5 Real Price Effects

3.5.1 Contractor Costs

92. We note that Ofgem have used the EC Harris report and Baxter indices to derive assumptions for contractor real price pressures, however we are disappointed that they have only used a limited update of NGG's earlier analysis that supported our BPQ submission. Completing a full update on the latest EC Harris report and Baxter indices indicates that contractor prices will rise at 3.1% pa and not 2% pa as used by Ofgem.

93. In addition to this increase in contractor inflation, the EC Harris report identifies that there is a +1.65%pa differential between contractor inflation in London and that of the rest of the country.

94. This is outlined in more detail in our response to Investment 4.1.

3.5.2 Real Growth in earnings

95. In the Initial Proposals Ofgem states "The evidence shown in the Table [A7.4] suggests that real growth in earnings ranges from 0.4 to 1.7 per cent per annum with recent utility settlements within a slightly lower range. On this basis we consider that real growth of earnings of 1 per cent per annum is appropriate."

96. However, NGG do not agree with the conclusions drawn by Ofgem. We have 4 main points of dispute:

- Not all the 10 quoted sources reflect real growth of earnings,
- The quoted sources mix historical, future and point in time findings,
- The findings from the Ofgem commissioned Inbucon report are misquoted,
- Not enough weight is given to the Hay and HM Treasury findings which are about future rather than spot.

Each of these 4 points are explored below.

a) **Not all quoted sources reflect real growth of earnings -** A number of the indices in Table A7.4 reflect base annual salary increases rather than real growth in earnings. This is important because pay settlement data only documents the amount by which salary

ranges or reference points increase i.e. the data does not take into account payments for performance, merit, progression, promotion, allowance rates increasing, etc.

The Office of National Statistics, in their document entitled "The difference between pay settlements and earnings growth" estimate that average earnings growth was 1.25% higher than average pay settlements over the six year period from 1998 to 2004.

b) **The quoted sources mix historical, future and point in time findings -** The majority of commentators on earnings growth stress the importance of long term historical averages and taking account of the full range of future forecasts.

In such a way, Hay look at trends over the past 10 years (average RPI + 1.7) and Inbucon on their own historical research (RPI + 1.7 to 1.9).

Similarly, both organisations make central use of the forecasts produced by HM Treasury. HM Treasury produce a frequent 'Forecast for the Economy', consolidating inputs from both city and independent non-city forecasters (44 organisations in the latest data available). These inputs cover both RPI and average earnings growth. The HM Treasury average earnings growth forecast for 2008 is 1.6% above RPI.

It is far less robust to put similar emphasis on single forecasts or on specific, narrow, points in time. For example, earnings growth fell below RPI for a short period in 2003, due to a steep and unexpected increase in inflation, but over the current price control has not remained at this level. Similarly, inflation was also unexpectedly high in the latter part of 2006/7 and as there is a generally acknowledged lag that exists between inflation and earnings rises, RPI+ increases over the last few months have been lower than the historical averages and the future.

c) **Inbucon information is misquoted -** On Page 4 of their Report, Inbucon state that "we expect Employment Costs to increase by approximately 1% per annum over the next six years". However, other detail within the Inbucon Report directly contradicts this. For example:

a) "Our research shows that, historically, salary growth tends to be within 1.7 – 1.9% above RPI",
b) "The correlation between RPI and wage growth will be maintained and overall wage growth will continue to fall within a range of approximately 1.5 – 2.0% above RPI".

In addition, Inbucon include an annual increase for Allowance & Overtime Growth and allocate a Skills Shortage Premium to National Grid. These are included in the Table below, along with Inbucon's assumptions on RPI and Wage Growth.

Factor	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13
RPI %	2.40	2.40	2.40	2.40	2.40	2.40
Wage Growth %	4.15	4.15	4.15	4.15	4.15	4.15
Allowance and Overtime Growth %	0.83	0.83	0.83	0.83	0.83	0.83
Skills Shortage Premium %	0.42	0.42	0.42	0.42	0.42	0.42

Table 3.10 – Inbucon's assumption on RPI and wage growth

In short, Inbucon's view is that earnings growth over the next 6 years will be constantly at 3.0% above RPI.

d) **Work commissioned by NGG as part of TPCR and DPCR -** The Hay (June 2006) report's summary figure included in the Initial Proposals Table A7.4, looked at past market real pay growth trends, prospective trends in the future, as well as an analysis of specific factors affecting pay levels in National Grid.

Hay concluded that average earnings compared to RPI (quoted in June 2006 Report) had increased as follows:

Period	Average Earnings Above RPI
5 Years from March 06	1.7%
10 Years from March 06	1.75%
20 Years from March 06	1.72%

Table 3.11 – Real Average Earnings

Using salary forecasts from HM Treasury (for 2007 and 2008), Hay conclude that future average earnings growth in the market is likely to be around 1.6% per annum.

However, in terms of future increases specific to National Grid, Hay also indicate that there are a number of industry specific factors – skills shortages (similar to the Skills Shortage Premium used by Inbucon), demographic challenges, heavily unionised environment etc that are likely to make it difficult for us to limit increases to 1.6%. As such, Hay concluded that planned earnings growth of RPI+2% was not unreasonable.

97. In summary, RPI+ comparisons are the long established way of looking at pay settlements and average earnings increases across industry.

98. As part of our Business Planning and PCR process National Grid has forecast employee costs for a period of 7 years. Taking into account only recent average earnings increases (as being used by Ofgem) or the views of individual forecasters is likely to increase the risk that projections may ultimately be significantly over or under the actual levels. Similarly, taking only pay settlements into account is likely to understate actual earnings increases.

99. As such, National Grid took into account the following factors in forecasting future employment costs for our Business Planning process;

- Average earnings growth for a minimum 5 year period ,
- Our historical situation i.e. previous average earnings growth for NGG employees,
- Consolidated forecasts for future earnings growth (i.e. the range of forecasts made by both city and independent analysts) produced by bodies such as HM Treasury,
- Our individual circumstances and employee context (e.g. additional demands placed upon us by our demographic profile, skills shortages and the continued expectations of our key Trade Unions for RPI+ settlements).

100. In addition, we engaged Hay to test our assumptions as part of the TPCR and maintained the assumptions for the DPCR forecasts. Given the current point-in-time settlements this April we have re-engaged Hay to review any impact. Their conclusion is that there is no change in the long run real wage pressure faced by NGG.

HayGroup Real Wages Growth April 2

101. We feel that both the work done by Hay and that carried out by Inbucon on behalf of Ofgem validates our original assumption of RPI+2%. We would also re-iterate that these RPI+2% assumptions were not adjusted as part of TPCR, i.e. Ofgem accepted our real wage assumptions as part of the TPCR process just six months ago.

3.6 Errors and Inconsistencies

102. There are a number of issues associated with Ofgem's normalisation of submitted costs which we have previously pointed out, and are disappointed that these have not been appropriately rectified. These issues impact upon the base year costs and so directly influence the allowances.

103. We support Ofgem's view, as noted in the Initial Proposals, of using 2006/07 actuals as the base year. This is necessary, both as it is the first full year of operation for all companies post network sale and to remove the current inconsistency in the selection of base year between Ofgem's consultants PB Power and LECG. PB Power has used 2005/06 actuals and LECG 2006/07 forecast. LECG used the 2006/7 year as they stated "2006/7 data better represents a steady state level of costs and activity"[15] and that there is a "distorting effect on the underlying cost base in 2005/6"[16].

104. As such, we expect the LECG, PB Power and Ofgem's work to update the benchmarking based on 2006/7 actuals to correct for the following errors and inconsistencies in their work for the Updated Proposals.

3.6.1 Indirect costs

105. In the Initial Proposals**,** Ofgem's consultants have been inconsistent in their treatment of non formula overhead costs. PB Power excluded the element associated with indirect support functions costs, but LECG have not made the corresponding inclusion.

106. This credit (£15m) relates to the indirect support functions that provide support to excluded service activities such as metering, and as such it is appropriate to exclude these costs from the PB Power 'direct' analysis, but they must be accounted for by LECG to ensure consistency. Applying the non formula overhead credit correction to LECG's benchmarking will reduce the identified disallowances for NGG by 25%.

107. Unlike other activities, the benchmark used for IS has looked at the average costs over 2005/06 to 2012/13. Within our forecasts, NGG included a significant efficiency saving (costs fall at 4% pa). Given that NGG is the second cheapest in the IS benchmark, it is impacting on the upper quartile benchmark and consequently this benchmark already has an element of productivity (and real prices) in it. In rolling forward the benchmark into allowances, Ofgem (appropriately) did not apply an uplift for real prices, but did (inappropriately) include the

[15] Benchmarking National Grid Gas Distribution's business support services, LECG, pg19 4.13
[16] Benchmarking National Grid Gas Distribution's business support services, LECG, pg19 4.13

annual reduction for productivity of, on average, £2.3m pa. Ofgem must discount its productivity assumption for this activity.

108. In addition, NGG believe an inappropriate normalisation of £1.7m has been made to transfer costs from repex to opex with respect to replacement procurement activities. These costs are solely associated with repex, procured by NGG rather than the contractor in order to gain procurement efficiencies, and accepted by Ofgem in our historic MRIM actuals. As such, this is an invalid normalisation and should be left in repex. This concern is enhanced by the fact that, in the LECG report on NGN[17], both the inability to identify the costs of logistics, in NGN and their operating model would point to the likelihood that this cost item is in repex. We note that in Appendix A5, paragraph 1.16 of the Initial Proposals, that Ofgem state that they are going to give this further consideration.

3.6.2 Atypicals

109. Ofgem have inappropriately not recognised a number of our atypical (one-off, non recurring) items in 2005/6, such as the atypical level of Goods Received Not Invoiced (GRNI) accrual release. Our response to the Accounting Issues report (27 February), the bi-lateral meeting (21 February), and the working level meeting (29 March) put the case that these costs were atypical in nature and with the 2006/7 latest forecast supported this.

110. Our arguments were noted by Ofgem and, in the third top-down report from Europe Economics (10 April), half of the accrual release was included (although un-intuitively was applied to wrong year!). However, inconsistently, this was not applied to the direct cost analysis that PB Power were engaged in.

111. The validity of excluding the atypicals from the 2005/6 direct opex is further supported by the 2006/7 actuals submission. In 2005/6, the atypical level of accruals was £14.5m, and this reduced to £2m in 2006/7.

112. These atypical accrual releases have been inappropriately included in the benchmarking, i.e. lowering the underlying level of NGG costs. Consequently, some of the upper quartile activity benchmarks have been calculated at too low a level, disadvantaging 6 out of the 8 networks.

3.6.3 Pensions

113. In order to normalise for differences in pension rates, PB Power normalised pension costs to 22%. Thus, later in the analysis, to be in line with Ofgem's stated principles on pensions, an

[17] LECG 16 April – NGGD, table 133

appropriate uplift to future cash contribution pension rates is required. We have the following issues with this calculation that will need correcting in the 2006/7 analysis prior to the Updated Proposals:

- In converting total pensionable salaries and wages to the opex element, Ofgem have removed non-formula pay costs. However, in the source B4 pensions' table non-formula pensions' costs have already been removed. Therefore, the non formula element has been removed twice.
- In applying the uplift to the cash pension contribution rate of 30.9%, for direct costs Ofgem have made the adjustment from a rate of 28.9% not the rate used by PB Power of 22%.

3.6.4 Service Relay after Gas Escape

114. PB Power transferred some of the costs associated with this activity from repex into opex. Although we do not agree with this transfer, if it is to normalise organisational/operational differences, then NGG accept the transfer. However, it is being transferred into the wrong opex activity.

115. The normalisation transferred, on average, around £2m pa per NGG network into the '*emergency'* opex activity. This service relay after escape work is undertaken by our Repair and Replace teams and not first response emergency engineers. As such, if it is to be treated as an opex activity, then the associated cost normalisation must go into the *repair* activity.

116. Given that this normalisation is not being made to all network owners, the current treatment by PB Power results in an inaccurate upper quartile benchmarking for both the emergency and repair activities.

3.6.5 Outermet

117. The top-down analysis has repeatedly been carried out with errors in the data, indeed we have not received a single top-down analysis that did not contain errors. NGG note that the Europe Economics top down regression work has been discarded between the 4th Consultation and the Initial Proposals, and that Ofgem have endeavoured to produce its own top down regression. NGG are disappointed to see however that the errors that accompany this area of work have continued with regard to the treatment of the Outer Metropolitan area (outermet).

118. The outermet area of London is managed and operated by our London area, gaining operational efficiencies given its proximity to London. However, from the National Transmission and hence Local Distribution Zone (LDZ) it is in East of England network and is treated as such with respect to gas volumes and hence formula revenues. Given this, a normalisation of costs and appropriate statistics (excluding gas volumes) from London to East of England is required.

119. In the Initial Proposals, this adjustment has been applied inappropriately to customer numbers but not the costs or length of pipe driver. Given the small sample size (8), this does have a material effect, not only on these two networks but also the overall slope of the regression, hence impacting all networks, with Southern network being adversely impacted by over a £1m per annum.

120. As requested by Ofgem, the 2006/7 actuals BPQ submission have been provided with outer met costs within East of England; hence this should eliminate this error for the Updated Proposals, post the use of 2006/7 actuals in the benchmarking work.

3.6.6 Transparency of analysis

121. NGG are disappointed in the transparency of information being provided and concerned that this may lead to invalid allowances due to errors. By developing spreadsheets that held all eight networks detailed data, the complexity of the consequential data handling, and the sheer size of the spreadsheets with necessary supporting text has resulted in, together with confidentiality issues of supplying data across DNs, has led to time delayed provision of spreadsheets and traceability.

122. Following the publication of the Initial Proposals, NGG could not fully trace either the opex or repex analysis. Meetings have been held and Ofgem have provided additional information that has helped, but NGG are still concerned that there are errors, specifically with regard to:

- Full traceability of normalised costs, we can get close but can not fully replicate. Given the small sample size, any errors here could materially affect the results.
- The fact that in Ofgem's own trace of movements there is a material unknown movement.
- Differences in normalised costs between top-down and bottom-up. For example, it appears that our logistics costs have not been included in the top-down analysis. This removes £4m from the top-down results, so affecting all networks.

3.7 Inadequate GDN Normalisation

123. As described in 3.6 there are numerous examples that highlight how Ofgem's bottom-up analysis is some way from being adequately normalised, including bogus efficiency spreads across NGG's networks and 'gap-generating' cost drivers. Further to these, Ofgem have not explained how they have accounted for the impact of disparate operating and investment strategies on opex. Our key concerns in this area are:

3.7.1 Accounting for Different Investment Strategies

124. An area that requires substantive further work between now and the September update is the need to incorporate the impact of the GDNs' differing investment strategies. As can be seen from figure below, average annual net capex per customer over the 16 year period 1997/8 to 2012/13 will be more than 65% higher in sold GDNs than in NGG's networks[18].

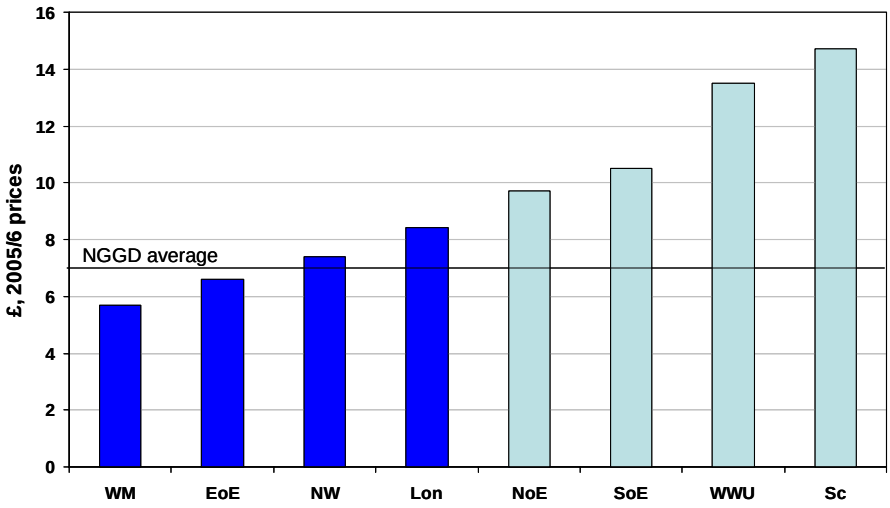


Figure 3.7 - Average net capex per customer – 1997/98 to 2012/13

125. It would be reasonable to expect this enduring and very significant difference to have some impact on the current and future operating cost requirements of the businesses. While some of the difference will have come from different capacity requirements, there are many other areas where capex/opex trade-offs are made within GDNs, for example regarding:

- mains reinforcement versus pressure elevation,
- New LTS pipelines for diurnal storage versus continued maintenance of holders,
- Replacement of plant and equipment versus repair.

[18] Based on GDN capex allowances from the Initial Proposals

126. These decisions can have a material impact on relative capex and opex levels – put simply networks with a greater proportion of aged assets require more asset management assessment and incur greater on-going maintenance and repair costs. Although difficult to quantify in detail, analysis based on Ofgem's assumptions for capital substitution suggests a 2.1%% difference in opex could be expected after 15 years of divergent investment. NGG's lower capex over this 16 year period is consistent with a higher level of opex, but Ofgem's assessment to date and the initial proposals effectively select the 'lowest of both'. Improving the sophistication in this area is an important aspect of the summer assessment work, particularly in the direct opex areas of work management and LTS maintenance. Further detail on this issue, including specific areas for further assessment, is given in 3.4.2.3.

3.7.2 Indirect Costs – Different levels of Capitalisation

127. Figure 3.8 shows the differences between the NGN and NGG operating models. NGN has outsourced its asset management and operational activities (other than system operations) to UUOL and the costs charged by UUOL are likely to include overheads (equivalent to a contractors charge). As such, these costs would be capable of being capitalised under their accounting policies, in contrast to NGG, where only those overheads directly incremental to investment can be capitalised in the accounts. Ofgem have not provided evidence of normalisation for this inherent difference in capitalisation levels.

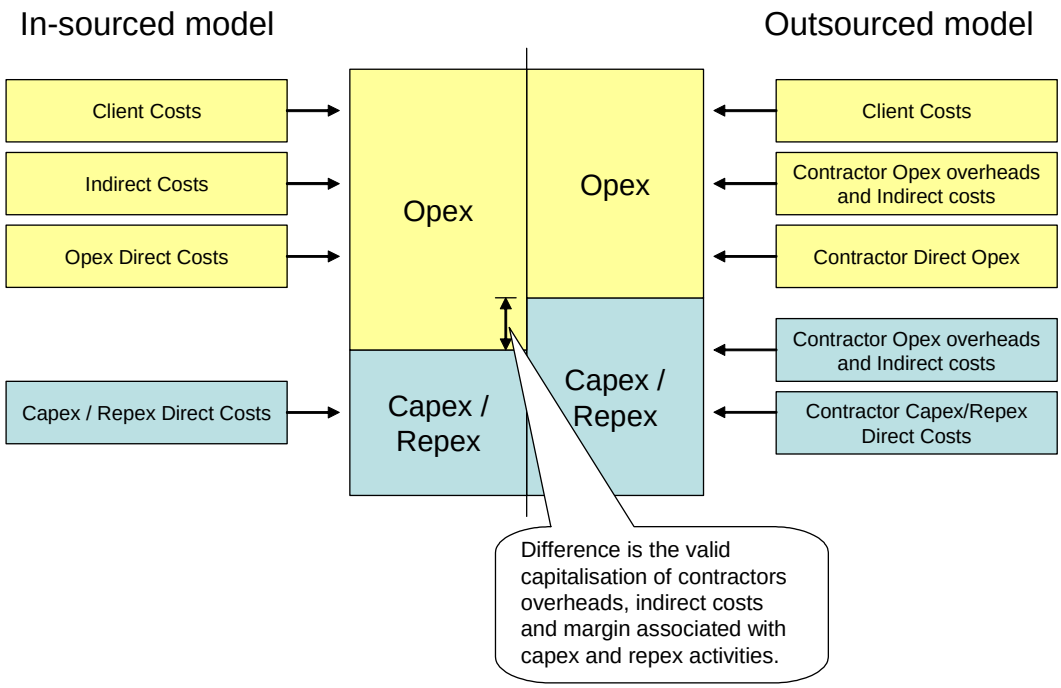


Figure 3.8 - Operating model impacts on opex/capex allocation

3.7.3 Indirect Costs – Centralisation and marginal costs

128. In the proposals, NGG's activities are presented as significantly less efficient than SGN's (see Table 3.12 below), even after accounting for the acknowledged Ofgem error in the analysis (see 3.6.1). We are very concerned that a) SGN's depot model and b) SGN's use of marginal costs creates an unsustainable benchmark. For SGN's support to continue to have influence over the analysis we will require positive assurance that these two effects have been adequately normalised.

	NGG	SGN	NGN	WWU
Indirect Costs	35%	1%	33%	36%

Table 3.12 – Indirect Costs disallowances as a % of normalised costs

129. NGG and SGN's have different operating models. This inherently brings about 'cherry-picking' issue that Ofgem have recognised. With NGG's centralised model contrasting with SGN's deport model which is more devolved model and as such is likely to lead to responsibility for some support activities remaining within the line management in the field. Activity definition has not been at a level that can pick up these effects and as such this will, in part, explain why National Grid appears more efficient that SGN on direct costs, but vice versa for indirect costs.

130. NGG has greater concern over the benchmarking against SGN's indirect costs that are at marginal costs. In the 4th Consultation Document Ofgem make a statement that SGN's activities are at marginal costs. They state that they are considering whether this may create an unsustainable benchmark. No adjustment has been made in the Initial Proposals from what we can see.

131. The LECG reports confirm the point raised in the 4th Consultation Document that SGN indirect costs that services provided by their parent company SSE are only recharged at marginal cost and 'SGN is not charged for services where SSE does not incur extra costs (e.g certain overhead costs, services utilising SSE's spare capacity ,etc)"[19].

132. With SGN's costs at marginal prices, then this is causing an inappropriate and unachievable benchmark. For instance, IS costs to support say Finance may not be included (they are appropriately in our costs), or SGN's property costs to support IS may not in their costs (they are appropriately in ours). This will have a material, inappropriate impact on the benchmark.

133. We suspect that this, together with potential operating model differences is leading to the significant 'gap' between SGN and all other network operators.

[19] LECG report 16 April - Scotia Gas Networks, para. 5.5

3.8 Indirect Cost Benchmarking – other issues

134. We accept the overall approach taken by LECG to undertake the analysis by ownership group for indirect costs (as this removes cost allocation complications), the use of 2006/7 forecasts rather that historic 2005/6 actuals (which are not a full year's costs of ownership) and the normalisation between activities that has been carried out (in order to, as best as possible, get like-with-like comparisons).

135. However, with such a limited data set (4) both the choice of high level driver and potential influence of outliers in an activity brings about uncertainty with the quantum of the 'implied efficiency savings'.

136. Further to the issues raised with regard to Errors and Inconsistencies (see 3.6) and the need for further GDN normalisation (see 3.7) NGG has the following additional issues with specific benchmarks from the LECG analysis of indirect support costs.

3.8.1 Finance and HR - External and Internal Benchmarks

137. We believe the use of external benchmarking for Finance and HR activities is not applicable in the case of this review.

138. In deriving a comparator group, it is imperative that normalising adjustments are made to ensure a like for like comparison between the GBP external comparator group and the GDNs.

139. NGG have joined the benchmark group and following a review of the 'input' information, NGG have identified the following three areas where it is clear that like with like benchmarks does not exist:

- NGG's Finance activity includes £1.9m for a specialist IS end user finance IS section (SAP competency centre). This is clearly not in the GDBP benchmarking definition. NB It may be that it is appropriate for this cost to be normalised to IS.
- NGG's finance activity includes £0.7m associated with purchasing elements of the purchase to pay process which are not in the GBP benchmark. NB We suspect that other network operators have this activity in Finance so no normalisation between BPQ activities is required.
- Our HR costs include £0.4m of employment costs held centrally on behalf of the business, for example BUPA costs for line departments personnel.

140. Given the above, these costs must be removed from the benchmark and as such the implied efficiency saving', based on the external benchmark will be reduced from £8.8m to £5.8m for finance and HR combined.

141. There are numerous other reasons for the remaining 'gap' with this external benchmark, including:

a) Composition of the benchmark – where there are issues around:

- Corporate Costs may not be included by all entrants in the GBP benchmark.
- Territory: Differences in cost base must be adjusted for in any study, with differences in salary, social security (NI) and pension costs etc, likely to be material.
- Market Sector: Only 4 utilities are included out of a total of 60 comparator firms, which with the highly capital intensive nature of utilities will adversely impact the shape of the overall finance function and cost compared to non utilities. As an example, utilities typically face an increased level of EU legislation.

b) GBP HR benchmarking information allows one to calculate the average employment cost of HR staff in the sample, that value is some 25% below the average employment cost for NGG. In late 2005 National Grid engaged the Hay Group to evaluate our market position against the indices Basic Salary Practice (all guaranteed elements of cash remuneration) and Total Cash Practice (base pay plus variable payments). Hay concluded that, against both indices, National Grid conformed to median pay levels (indeed for some groups of employees we paid lower quartile levels).

As such NGG would argue that LECG/Ofgem should, if they are using an external benchmark (which we disagree with), use the GBP HR FTE per organisation FTE. This would reduce the 'implied efficiency saving' for NGG from £3m pa to £2.2m pa (pre-adjustment for central held costs). [20]

However, even here, we doubt the robustness of the LECG work and the conclusions drawn from it. The benchmarking work previously undertaken for National Grid by

[20] Given operating model differences, NGG understand that LECG cannot use this benchmark for some of the other network operators. However, with NGG operating an in-house operation the FTE benchmark is valid and as such indicates that the GBP HR benchmark (and consequently the Finance benchmark) is not appropriate.

Saratoga (June 2005), demonstrates National Grid (1 HR FTE per 119 Organisation FTEs, 82nd Percentile) to be significantly better than Saratoga's best quartile performance.

c) Sold networks have largely set up green-field site functions in these activities, with the exception of small decision support staff c.12 FTEs. An outcome which shows all GDNs to be inefficient against the benchmark casts further suspicion over the analysis and the results, especially including SGN with their decentralised operating model given that at sale

- In Finance, the sold networks were transferred without any financial systems and minimal finance capability, i.e. management accounting, budgeting and forecasting capabilities only. This larger cost element of functions such as accounts payable/receivable, payroll, tax, treasury etc. were not transferred and, depending upon the GDN operating model, will have to have been built up, bought in or provided from other parts of the group.

- In HR, the sold networks were transferred with only 1-3 personnel at most to deliver day to day HR capability only. As with Finance, the more strategic HR functions and disciplines such as reward, national trade union management, policy development, talent management, succession planning, inclusion and diversity etc were not transferred.

We suggest it is highly unlikely that, in the 15 months since sale, the new owners have all, separately, built in finance and HR functions that are between 17% and 69% inefficient.

d) Whilst LECG recognise that benchmarking studies should be 'validated' against the results of other studies, interestingly, LECG choose to ignore the positive results of the benchmarking work that Deloitte delivered as part of the TPCR. Of the studies that are considered relevant, the results neither validate LECG's findings, nor produce such aggressive findings.

Based on the above the only data which Ofgem can feasibly present is the GDN comparator analysis. By choosing to use this external benchmark LECG are introducing a further element of cherry picking. Finance itself is not an activity a GDN should strive to be world class at as it is not part of our core activities.

Driver	NGG Ratio	Benchmark Ratio	Implied Disallowance
Finance to external	1.16%	0.62%	5.84
Finance GDN	1.16%	0.97%	2.06
HR to external	0.44%	0.17%	2.96
HR GDN	0.44%	0.28%	1.73

Table 3.13 - Impact of different benchmarks

3.8.2 Insurance

142. On insurance, NGG are pleased that adjustments for uninsured liability claims have been appropriately made and an allowance given for failure to supply (on the latter this level is inappropriately low – see answer to question chapter 5, question 3). However, NGG have significant concerns on both the benchmark disallowance and on the market trend assumption on insurance

3.8.2.1 Insurance Benchmark Costs

143. Excluding the £3m costs associated with specific insurance costs associated with uninsured liabilities and failure to supply, the NGG metric of insurance costs as a percentage of adjusted revenues is 1.18%. This is still higher than the other GDN owners, and equates to an underlying (i.e. excluding the above two factors) disallowance of £2.3m pa from the upper quartile benchmark value.

144. NGG firmly believe that the simplicity of the benchmarking and lack of transparency is still leading to an inappropriately high disallowance. NGG's main arguments to support this are:

a) **Choice of driver** – The LECG benchmark is based on an adjusted revenue figure, i.e. LECG have removed the sculpting of the RAV in calculating revenues. Insurance costs are in fact driven by a number of different specific drivers, as detailed and analysed in the detailed report carried out by insurance specialists Marsh, as part of the TPCR. There is no single 'best' driver, and changing this driver can bring about significant differences in the benchmark results as can be seen in the table below. Alternative drivers, include 'true' revenues do drive part of our insurance costs, equally total spend (ie opex + capex + repex) and or FTEs drive insurance. These all indicate a gap to the metrics of the other owners, but the quantum is materially different.

Driver	NGG Ratio	Benchmark Ratio	Implied Disallowance
% of adjusted revenues	1.18%	0.98%	£2.3m pa
% of revenues	1.12%	1.03%	£1.0m pa
% of total spend	1.37%	1.20%	£1.5m pa
% of ftes	2520	2188	£1.7m pa

Table 3.14 - Impact of different benchmarks based on adjusted NGG costs of £12.7m

b) **Transparency / Suitability of Benchmark Cover levels** - The LECG reports of other GDN owners, whilst not explicitly showing our concerns over other GDNs having appropriate covers (transparency) there are references that do indicate this which do however lead to issues that in our opinion are fundamental to evidence of an inappropriately high disallowance of NGG insurance costs. Points to note include:

- **SGN** - LECG's report on SGN[21] states that the forecast for uninsured claims appears to be exceptionally low compared to other GDNs. They then suggest that this could imply that SGN has underestimated its uninsured claims costs. To apply an efficiency to others having questioned the submission is not appropriate. In addition, the costs associated with claims handling are reported as "immaterial", this is a surprising statement to make.

  LECG state that SGN obtains insurance advice from SSE who compare prices and coverage of different insurers based on internal experience (e.g. from electricity insurance). The risks of the GDNs are different from electricity as are the claims profiles and NGG consider that this may give credence to the point made by LECG previously that the new management teams limited experience of managing the new businesses may affect their ability to provide accurate and well supported forecasts.

- **NGN** - This is also evidenced in the report concerning NGN[22] where the costs of an explosion claim are partly covered and there is insufficient information available to establish the final costs to be borne by NGN. Given that time spent on insurance activities is described as negligible then this could cause concerns as to the provision of accurate and reliable forecasts.

[21] LECG report 16 April - SGN, paragraph 8.18 to 8.22
[22] LECG report 16 April – NGN, paragraph 8.2

- **WWU** - The low limits of indemnity and narrower coverage referred to by LECG for WWU[23] also suggest that this would lead to a lower premium. To then benchmark others with wider cover and perhaps more appropriate limits would then lead to an inappropriately high disallowance on premiums.

c) **TPCR Findings** – The above points are backed up by the findings of the detailed review carried out, by the insurance specialists Marsh, for Ofgem as part of the TPCR; where Marsh concluded that insurance was competitive and appropriately placed.

3.8.2.2 Insurance Market Trend

145. LECG have applied the cyclical view to insurance costs that is inappropriate because of the use of a captive insurance company that only accesses the market for reinsurance, whilst claims, which represent over 30% of the NGG's insurance costs, are not influenced by the factors affecting the insurance market cycle.

146. NGG have submitted separately an updated report from Marsh, that details these points and, as with the report prepared for the TPCR, once again refers to the two cycles. This report clearly points out that it is inappropriate to reflect the projection of pricing using the market cycle for NG's retained costs and captive premiums. NGG believe Marsh are unequivocal in their emphasis on this point.

147. The Initial Proposals quote the non marine market as a sense-check to support the Marsh cyclical view. However, as indicated previously, the non marine market covers a wide variety of businesses that does not always include utilities, which are often classed as energy risks. The coverages required are specific to the gas industry. As GDNs have identified, the major risk for GDNs is a major supply loss, and GDNs have highlighted the consequences in terms of costs and liabilities. The non marine market rates do not reflect the risks faced by GDNs, and this sense-check in the Initial Proposals is inappropriate.

148. The report also comments on the impact of the floods in the UK, that are unprecedented, where NGG was affected in two networks. NGG would once again question the use of this cyclic approach. It is considered, given the magnitude of the losses faced by insurers, that the upturn on costs will be significant and the cyclical approach adopted may ultimately prove to be inadequate in funding the insurance premiums payable after such an event particularly as the event occurred at a supposed benign time of year with the market yet to face the hurricane season in the USA and the winter months in particular in the UK.

For claims costs Marsh do not suggest the use of a market cycle approach. Indeed the central purpose of (by way of example) a civil law award of damages is to compensate for loss,

[23] LECG report 16 April – WWU, paragraph 8.21

damage or injury and to suggest this is somehow connected to the vagaries of an insurance cycle is considered inappropriate. Marsh specifically make this point. Additionally, by reference to the International Underwriting Association index for injury claims and the UK RPI for property claims there would be appear to be sound logic in adopting a linear approach to uninsured claims in future that reflect appropriate indices. Personal injury claims inflation has been consistently at 10%+ per annum since 1989 and is set to continue at similar levels for the foreseeable future. This is confirmed by the data collated for the Third UK Bodily Injury Awards Study (the IUA/ABI Study), published in March 2003. The study is the biggest exercise of its kind ever undertaken, it covered more than 90% of the UK insurance market and looked at all claims going back to 1989.

149. The Marsh report was obtained given the conflicting views expressed by LECG and NGG. Marsh are recognised as global insurance experts and the report evidences the breadth of coverage that may not be available to others, in particular the failure to supply risk. Marsh of course are in a position to comment with authority on market availability of coverage and market issues. The Marsh premium forecasts for the Captive are lower than market forecasts for the risks referred to rather than those declared by other GDNs.

150. NGG note however that the submissions made in the BPQ are indeed lower than both the Marsh indications of what they believe the Captive and market premiums would be and in addition NGG have taken a far more conservative view of self retained claims costs than Marsh who have forecast increases of 8.5% pa.

151. NGG believe that the attached report from Insurance specialists, Marsh more than supports the submissions made by NGG.

3.8.3 Property

152. LECG's use of floor space per km and the associated costs do not appear to be like for like across GDNs. NGG's floor space includes allocations for its centralised support functions that may not be comparable when compared to the other GDNs. We believe that the GDN's support functions floor space and costs are not all factored into the analysis.

- Firstly call centre and national system operations costs are not fully adjusted for and this needs to be done as part of the September update (LE-NGG-168).

- Secondly looking at sold network sites before network sales our best estimate is that iDNs were each taking something of the order of 80 – 90,000 sq ft of direct costs before any allocation of any central shared services overhead. This is consistent with the position reported for NGN and SGN for both LECG reports. WWU, in comparison has

moved from reporting 153,000 sq ft in February to 70,000sq ft in April. This may be indicating that the sold networks submissions do not include any property costs relating to central shared services overhead.

153. Also total occupancy costs survey (TOCS) benchmark for office costs on new buildings is in the range £16 to £20 / sq ft. NGN and SGN benchmark at £14.1m and £10.3m / sq ft are significantly below average. This suggests that they have a significant number of industrial unit / depot type properties in their portfolio that are dragging the average down.

154. Our benchmark falls above the TOCS range. This is due to the impact of additional security, R&M and running costs of 24/7 critical activities currently not carried out by other owners (e.g. emergency call centre and system operation). In addition some service levels provided above the TOCS standard of service (e.g. green travel (£0.2m), free vend (£0.2m), restaurant etc.) giving a genuinely increased cost base, but also in part due to the high occupancy levels driving costs upward.

155. The Drivers Jonas in their work on TPCR looked at the British Council for Offices (BCO) Guide 2005, Best Practice in the specification for offices, states that "good UK practice for conventional occupancy is currently between 12 sq m and 17 sp m per person of net internal area.

156. Drivers Jonas found that National Grid had an allowance of 10 sq m per workstation which includes an apportionment for business support functions (such as meeting rooms, tea-point and break-out facilities) in addition to the workstation allowance. This considered by the BCO to be an efficient workspace density, this allowance benchmarks comparably with spatial standards currently in use by other Drivers Jonas Government clients and is recognised by industry as an efficient planning module which delivers cost effective use of space.

157. The BCO also stated that any further increase in density should be given careful consideration to ensure that minimum health and safety standards are being met. On calculating a benchmark of floor space per FTE for other network operators it shows them all to be between 5 to 7 sq metres per FTE. This shows them to be compromising on health and safety standards or supports the argument above that the data provided by them is not comparable to that supplied by NGG.

158. In addition NGN's operating model may see property costs being shared with capital, unlike ours. We are concerned that appropriate normalisation has not been completed. LECG / Ofgem must ensure that the comparison is on floor space is like-with-like.

3.8.4 Information Services

159. NGG are concerned about inconsistency in results from detailed benchmarking exercises undertaken in each indirect activity as part of TPCR and this high level benchmarking undertaken by LECG. As part of TPCR, Ofgem took up functional experts, for IS this was Compass, who concluded that "The sourcing strategy of NG clearly delivers benefits in terms of reduced costs to the organisation. As with any organisation there are areas where performance could be improved, but the overall conclusions is that NG is doing the majority of things well. Compass considers that both the CSC contract and selective sourcing of ADSM services are consistent with leading practice in sourcing of IT services (Compass Report, Page 9, Benchmark results)".

160. We are concerned that LECG believe it is valid to largely dismiss the conclusions from TPCR benchmarking analysis. Whilst we acknowledge that some of the elements of benchmarking were TPCR specific, it forms the latest comprehensive utility benchmarking undertaken since DPCR4. It is inconceivable to us that the overarching strategies that were deemed efficient in September are now only 10 months later, considered to be inefficient.

161. Difference to SGN is therefore believed to be due to their operating model and confirms the need for an uplift to be applied.

3.8.5 Procurement and Logistics

162. An implied performance improvement of 50-55% for procurement costs is not credible, with performance at this level resulting in a need to operate at the extreme end of the 'least cost' scale, which in our view would be to the detriment of the effectiveness for the company, and ultimately, consumers. This is also completely inconsistent with the detailed benchmarking carried out as part of TPCR. As part of TPCR the benchmark work carried out by the Hackett Group showed NG's overall efficiency of the Procurement and Logistics function to fall short of the world class performance by only 16%.

163. In LECG's SGN[24] report it states that "approximately 75% of SGN's L&P activities, measured in terms of operating costs, are performed SSE under the MSA. SSE recharges SGN the marginal costs it incurs in providing these services. No mark-ups are included in the recharges." Ofgem must proceed with caution therefore when using this analysis as the performance of outliers, particularly SGN, will have a disproportional effect in the implied performance improvement for National Grid.

[24] LECG 16 April – SGN , paragraph 13.2

164. Ofgem must proceed with caution therefore when using this analysis as the performance of outliers, particularly SGN, will have a disproportional effect in the implied performance improvement for National Grid.

165. We believe total cash spend to be a more meaningful indicator of overall procurement and logistics activity for this purpose. Total spend will ensure our repex activity with its substantial support from procurement and logistics to ensure efficient and effective materials availability, is fully captured. The use of total opex effectively ignores what is one of the largest drivers of P&L activity.

Driver	NGG Ratio	Benchmark Ratio	Implied Disallowance
% of total opex	1.27%	0.84%	2.63
% of total spend	0.83%	0.61%	1.99

Table 3.15 - Impact of different benchmarks

3.9 Direct Cost Benchmarking – other issues

166. In addition to the normalisation issues (see 3.6 and 3.7) and the fact that there are additional factors associated with operating in London (see 3.10) NGG has the following specific concerns on the analysis of direct costs.

3.9.1 Work Management

167. In developing a composite size variable for work management, PB Power have not actually reviewed the actual work activities of work management. If they had, then the prime work drivers would have included 'number of customers' in addition to the number of emergency and repair jobs. Table 3.16 compares the make up of the composite variable from PB Power with that which NGG believe is more representative.

	Emergency	Repair	Length	Customer
PB Power	30%	30%	40%	
NGG view	17%	25%		57%

Table 3.16 - Composite driver composition

Table 3.17 provides the rational for NGG composite variable

Activity	Value (£m)	Rationale	Customer	Emergency	Repair
Operations					
Operations	34.9	Based on workload drivers for workforce	34%	29%	37%
Distribution Support					
Management team	1.3	Fixed cost therefore the driver is customers	100%		
Customer Service	4.8	Call handling volumes directly related to number of customers	100%		
Dispatch	6.1	Support to Operations	34%	29%	37%
Business Improvement	1.8	Fixed cost therefore the driver is customers	100%	0%	0%
NRSWA	1.4	Function of Repair workload			100%
Engineering Support	7	Support to Operations	34%	29%	37%
Construction					
Construction	1.2	Support to Operations for standby and escape compliance			100%
Accounting Control					
Executive	3	Fixed cost therefore the driver is customers	100%		
Share Save/Task	-3.4	All aspects of work execution = Operations	34%	29%	37%
Network Strategy					
DNCC	4.2	TwH = customers	100%		
Advantica	4.1	Supports Operations	34%	29%	37%
Grid Comm	0.7	Driven by size = customers	100%		
Engineering Policy	2.3	Supports Operations	34%	29%	37%
Investment	0.6	Involved in investment and maintenance = customers	100%		
Information	1	Fixed cost therefore the driver is customers	100%		
Engineering Planning	7.9	Undertakes connections related enquires and LTS planning which are customer driven	100%		
Commercial					
Commercial	6.4		100%		
Total Work Management	**85.3**		**57%**	**17%**	**25%**

Table 3.17 - Derivation of NGG composite variable

168. From the above it is clear that the principle driver of work management is customers. In looking at Operations (the front line managers), their costs will naturally be driven by the level of emergency and repair jobs. However maintenance is fundamentally driven by customers (or volume) which in turn drives the amount of equipment and hence costs. It is not driven by km which drives repair and hence partially emergency. Maintenance is done on the equipment at AGIs etc, rather than the on the length of pipe. Likewise, a lot of the back office asset management and customer service activities, such as call handling are driven by customers not Km.

169. PB Power need to review their composite driver.

3.9.2 Repair

170. NGG has two issues with the repair analysis with regard to the derivation of the composite size variable and also the workload trend assumption.

171. With regard to the derivation of the composite size variable, PB Power has assumed that the proportion of repairs by diameter is equal to the proportion of mains by diameter, this is not the case. We do note however, that Ofgem have requested extra information in the 06/07 actuals to enable correct calculation.

172. Disappointingly, the substantial evidence and supporting information that has been submitted to demonstrate the impact on repairs has not be taken into account. Ofgem are assuming a rate of 3%pa, NGG believe a factor in the range of 1% to 2% is more appropriate.

173. The following figure shows historic repair workload for the period 2002/3 to 2006/7. This workload trend should be seen against a background of Increasing mains replacement activity and 2006/7 being the 2nd warmest year in recent history.

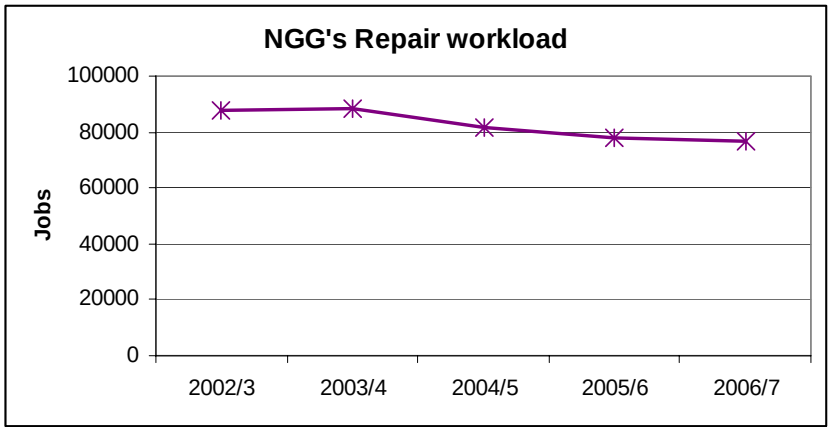


Figure 3.9 – NGG's repair workload

174. The overall reduction in repair workload of 3.4% pa between 2002/3 and 2006/7 can be primarily attributed to:

- 2003/4 to 2005/6 – the widespread one-off installation of pressure profiling equipment which enabled system pressures to be kept at a minimum despite organic load growth.
- 2005/6 to 2006/7 – an overall reduction of 2.1% was achieved against a background of significantly warmer weather.

175. In determining future repair workload reductions Ofgem's top down analysis considers some of the major influencing factors although their relative impact has been overstated and several important factors omitted altogether.

a) That the replacement programme is only replacing cast iron mains within 30metres of property. Public reported escapes will occur on the remaining 8% of metallic population that will not be replaced by the replacement programme.

b) There is a strong link between the number of escapes reported and the risk level of pipes. During the current price control period NGG has prioritised mains for replacement, pipes replaced have typically had an average value of 240. The progress made this period means that lower risk value mains will be replaced next period, with an average risk value modelled to be 90. The relationship, as seen in the figure below means that mains next period will give rise to only 40% of the escapes per km than the mains replaced in the current period. An important implication of this relationship is that the rate of escape reduction delivered by mains replacement will decelerate due to a much lower risk profile that at the beginning of the replacement programme.

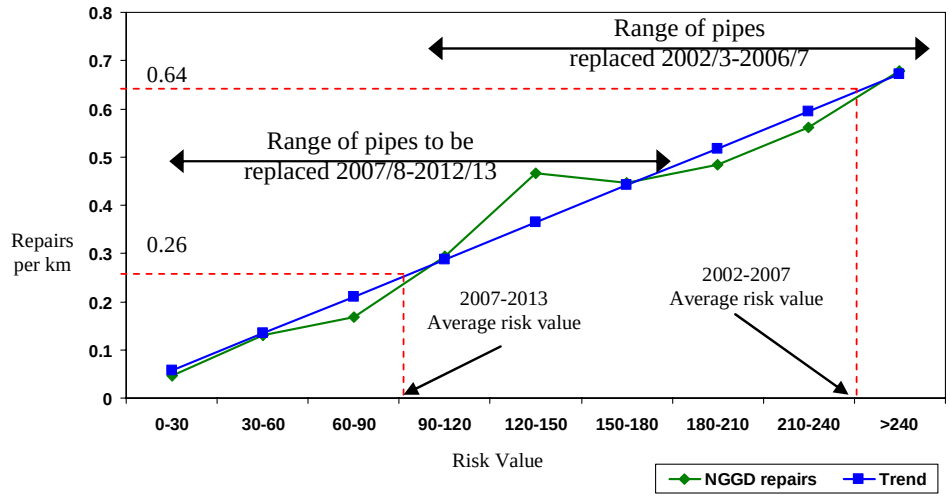


Figure 3.10 – relationship between repairs and pipe risk

c) Average system pressure and age have been considered by PB Power, via a unsubstantiated assumption using the combined impact of continued deterioration of remaining pipes and system pressures. This is a single assumption applied to all networks, which is wrong. Most of NGG's networks have pressure profiling systems in place, and with the exception of West Midlands, there is not an economic case to invest in new systems. We note that in the PB Power report on NGN[25], NGN assumed a 0.7% pa benefit from new systems. This is a prime example of our argument for differential treatment of capital substitution efficiency given the different capex levels between NGG networks and other operators.

d) This period, continued investment in gas conditioning has been carried out. However, as a result of the mains replacement programme an increasing proportion of the mains network is plastic. The impact of gas conditioning will reduce as the scope for future economic deployment reduces. Gas conditioning is installed only where it is economically viable and consequently our future policy is not to install any new installations. This will result in no positive (i.e. downward) influence in escapes over the next period, whereas this period has seen this influence.

e) In determining future repair workloads Ofgem have not taken into account the impact of weather. Although the influence of weather, and the above factors, is not possible to analyse precisely, 2006/7 was the second warmest in recent history and as such the overall trend in escapes this last period must be influenced by this.

176. Given the above factors, the assumption that there will be a reduction in escapes of 3% pa is over-estimated. In 2006/07 we experienced a reduction dropped of 2.1%, despite it being the 2nd warmest in history.

177. To provide Ofgem with confidence that our 1.25% future workload reduction is reasonable, NGG has undertaken further, both top-down and bottom up, giving a reduction range of 1.0% to 2.0% pa.

178. Acknowledged by PB Power the distribution system will deteriorate with age. It is not possible to model this degradation and as such reinforces NGG repair workload reduction of 1.25% pa. Our alternative top-down analysis utilises the PB Power's methodology correcting then for factors discussed above giving an annual reduction of 2%. The following figure illustrates how this value was calculated.

[25] PB Power, GDPCR (Opex) report 2, 18 June, paragraph 5.4.2

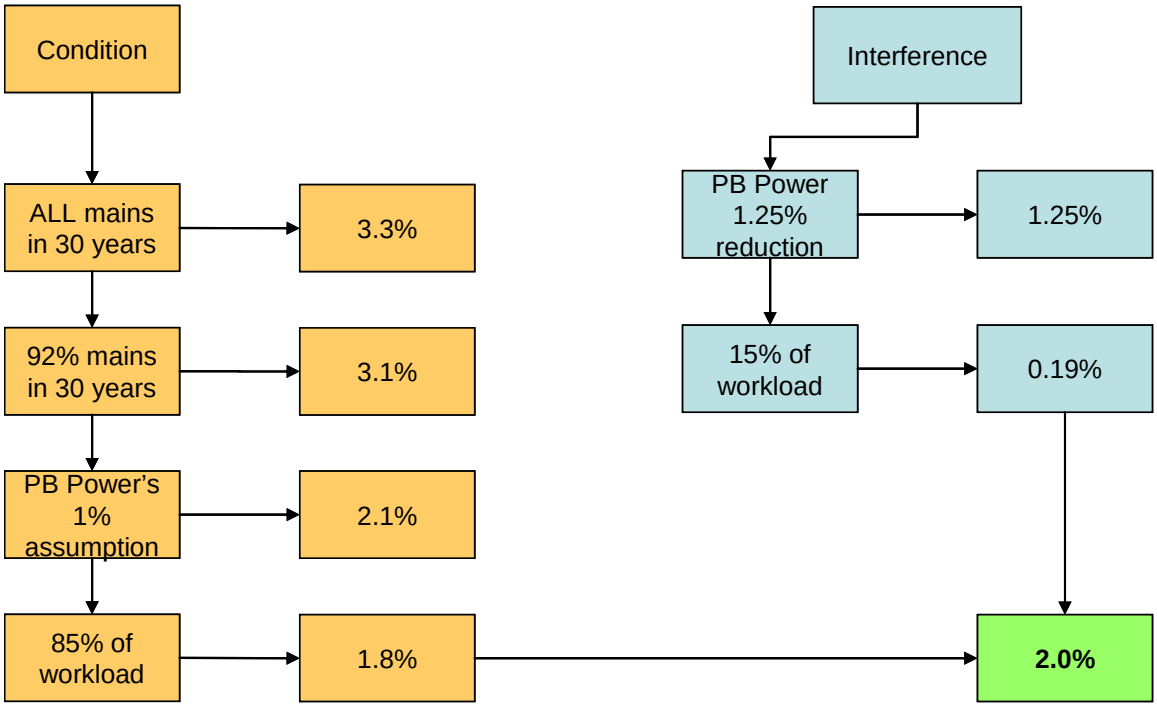


Figure 3.11 - Process map for using Top down model

179. A further view can be made by utilising the Industry recognised National Leakage Model to replicate the impact of the changing material population and increasing system pressures. Like PB Power, NGG is able to model the impact of system degradation. The 1.0% reduction in condition workload is therefore a maximum value.

The following figure illustrates how this value was calculated.

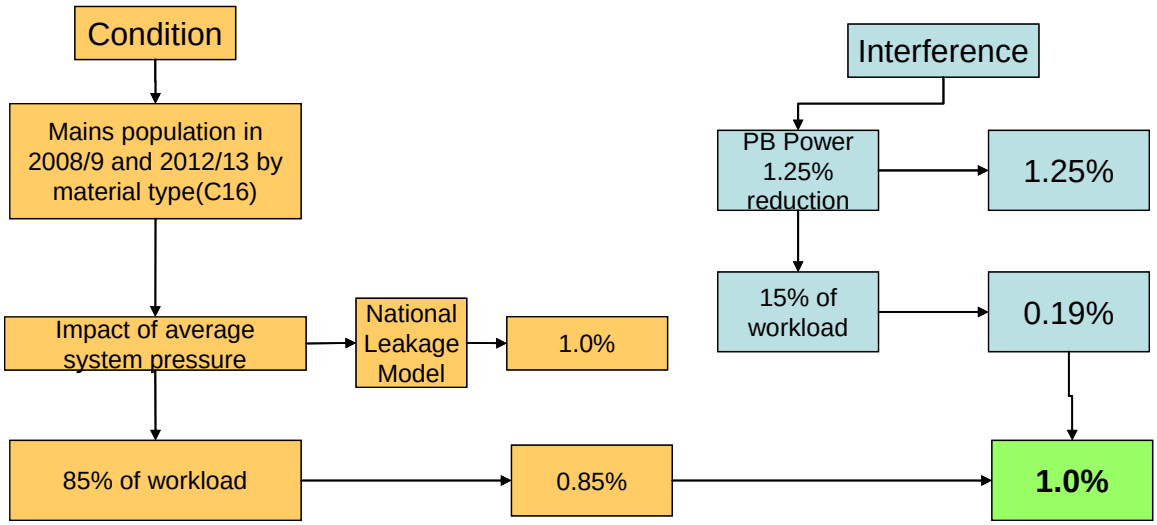


Figure 3.12 - Process map for using the National Leakage model

180. In summary, Ofgem need to reconsider the above information in assessing future repair workloads, which NGG firmly believe that 3% is too high and would lead to under-funding this activity, especially at the back end of the review period as the cumulative effect grows. A value in the range 1.25% to 2% is more appropriate.

181. The above factors need to be addressed by PB Power / Ofgem, additionally we would also point out that

- PB Power need to take into account the fact that 2006/7 was the second warmest in recent history and being the base year workload from which the assumed trend is applied, will require an uplift to seasonal normal temperatures.
- Ofgem's current proposals regarding the efficient delivery of our mains replacement programme include for additional down sizing of mains from that currently proposed by NGG (see investment 4.2). This would lead to an increase in system pressures with an adverse impact on repair workload. If Ofgem do not move on this point then an appropriate further reduction in the repair workload factor will be required.

3.9.3 Maintenance

182. Errors and omissions in allowances have occurred both through underestimation of legitimate costs included in the 2005/06 baseline costs and partial or insufficient allowance for spend items which were not incurred during this baseline year.

183. The principal flaws result from the exclusion of data which highlighted that maintenance spend can be infrequent, high cost and at times unpredictable.

184. As a result of this approach and the reliance on a desktop bottom-up rationalisation, based on simplistic drivers and a single year of costs, Ofgem have underestimated the funding required to maintain a safe and efficient distribution system by c£65m.

185. The key investment areas impacted by this approach are detailed below.

3.9.3.1 2005/06 benchmark and workload projections

a) Storage – Gasholder Maintenance

186. Table 6-12 proposes a bottom-up analysis of gasholder maintenance tasks which estimates the annual cost of operating a gasholder at £19,000 per holder. A number of significant cost categories have been omitted from this analysis and as a result it understates the true cost of £34,000. It does not make allowance for:

- Interceptor checks and consents
- Site maintenance – building maintenance, vegetation control etc
- Utility bills - electric booster costs are very high
- Electrical and instrumentation maintenance
- Non routine and fault work

Set out below is our view of all costs:

Annual Maintenance and repair costs per holder

	Unit Cost	number of units	x per year	Total cost	
Methane Extraction- Sampling, Inspection and Repairs	£ 120	1	2	£240	
Drain jetting & interceptor maintenance	£ 396	1	1	£396	Yearly inspection and ongoing repairs to the interceptor also visual inspection weekly
A' checks - labour	£ 29	4	52	£6,032	Two men for two hours averaged over the year
Quarterly check - labour	£ 29	24	4	£2,784	Two men for one and a half days
Annual Inspection - labour	£ 29	16	1	£464	
Annual Maintenance - labour	£ 29	80	1	£2,320	inc commissioning costs double dipping etc
Fall arrest inspections and repair	£ 104	1	1	£104	
5 yearly fan + jet booster maintenance 6 monthly	£ 4,000	1	0.2	£800	Inc 32 man hrs £640 for maintenance of holder fill and extraction equipment plus jet booster 5 yearly at £360
Holder cut off valve maintenance - labour	£ 29	16	1	£464	Two men for one day
Instrumentation costs	£ 778	1	1	£778	Inc holder cup monitoring maintenance, holder trip checks, methane extraction maintenance checks and all instrumention on fill and extraction equipment
General Repairs - Materials	£ 4,506	1	1	£4,506	Leaks, overplating, structural repairs, cup cleaning
General Repairs and faults - labour	£ 29	68	1	£1,972	
Carriage rollers repair & refurbishment	£ 2,032	1	1	£2,032	
Fencing	£ 78,000	1	0.033	£2,574	Approx 30 yr life
Site Husbandry	£ 1,000	1	1	£750	excl £250 exceptional cost eg tree cutting
Utility bills	£ 250	1	12	£3,000	averaged over 12 months
Consent to Discharge	£ 650	1	1	£650	averaged between costs to discharge into main sewers and watercourses
Fire and security risk assessments - labour	£ 29	3	1	£87	one contractor site security every two years and fire risk assessment every five years
Electrical	£ 4,414	1	1	£4,414	Includes all routine non routine electrical maintenance that is associated with running of holders i.e antifreeze systems site lighting electrically operated valves holder management systems sump pumps etc
COMAH	£ 400	1	1	£400	Includes testing of onsite offsite emergency plans liasing with local authorities desktop exercises for lower tier sites
				£34,367	

Weighted average used for industrial employees	£	£ 29
Instrumentation TS5	£	£ 35

Table 3.18 – bottom up analysis of gas holder maintenance tasks

b) Storage - Gasholder Demolition

187. Gasholders which become excessively expensive to repair as a result of degradation and unexpected faults must be mothballed and subsequently demolished. The cost of this demolition includes diversion of mains, relocation of any pressure reducing installations and land remediation. In the majority of cases there is little or no opportunity to achieve a self funding demolition from a land sale e.g. North West sites. The exception to this typically being the South East where property values for brownfield sites are generally higher.

188. As a result of the proposals' generalised assumptions the demolition costs of £6m, for which information was provided, have been incorrectly excluded from the recommended allowances. An example of a site where this will have an impact is Oswald Street column-guided gasholder in the North West. The site does not have a self funding land sale opportunity.

189. By implication, exclusion of this funding suggests that non-economic demolitions should not take place. This would place employees and members of the public in areas outside the South-East at risk from environmental contamination and failing structures which is unacceptable to NGG. The figures below show the maximum possible site value for gasholders by Network. They exclude the cost of removing old gas mains, and rationalising plant to enable sale and so presents an inflated value of the site. Nevertheless, it is clear that in many cases, outside the South East, maximum gross land sale value does not cover the cost of demolition as asserted in the proposals and may be as high as £30/m^3 of storage.

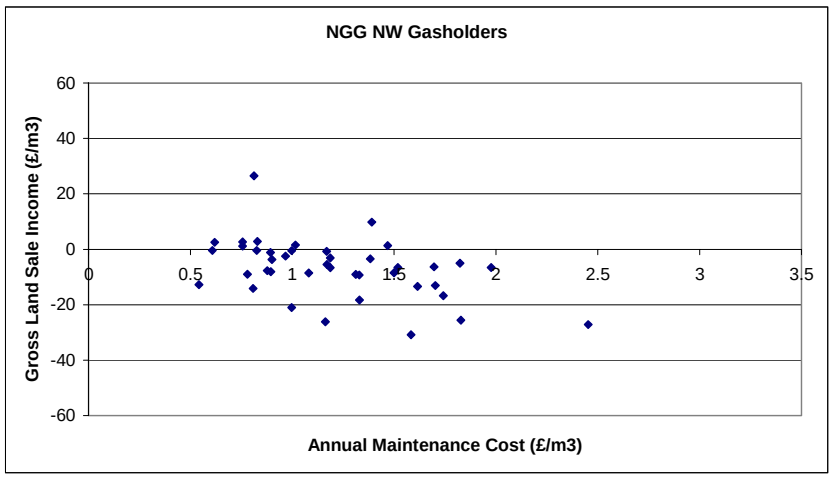


Figure 3.13 – NGG NW Gasholders

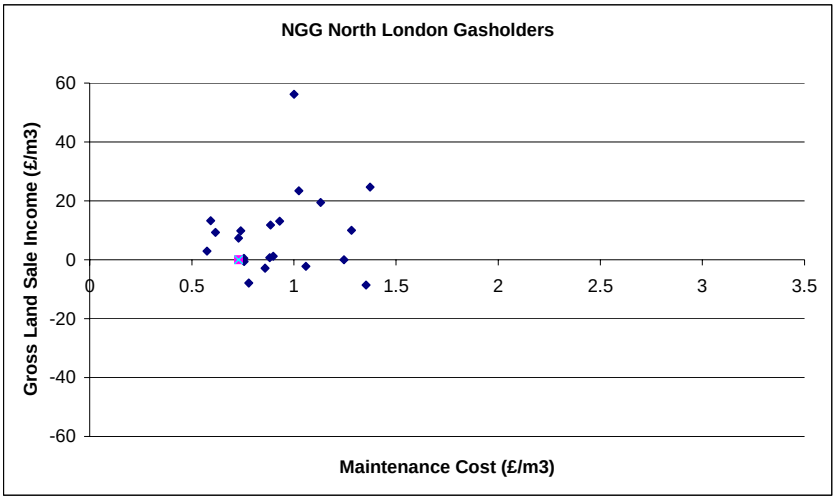


Figure 3.14 – NGG NL Gasholders

c) LTS – OLI defects

190. PB Power have proposed an allowance of £20,000 per OLI run generally and £40,000 per run in North London. This is a significant underestimate of the costs involved, particularly in London.

191. A typical rural OLI run of 25km will identify five faults. Each fault will on average cost c.£8,100 to investigate and remediate if necessary.

Excavation contractor	£3,500
Compensation	£500
Inspection contractor	£500
Materials	£1,500
Direct labour	£2,100
Total	£8,100

Table 3.19 – cost of typical rural OLI run of 25km

192. Therefore we anticipate a cost per run to repair defects of c.£40,000 outside of London. The PB Power proposal understates this by 100%.

193. The position in London is significantly more expensive, due to access and traffic costs. Following detailed reviews of long standing defects a prioritised programme has been developed in the short term with an estimation of the longer term run rate. Known defects in London are estimated to cost between £0.6-1.5m. An example of this is a defect discovered on the 30" Southall to Richmond to Fulham LTS pipeline which supplies some 350,000 consumers in West London. A number of defects such as dents and areas of metal loss were

discovered placing at risk the integrity of large parts of the London Network. The approval of this project (in March 07) at £0.5m reflected not only the severity of the defect but the scale and engineering difficulty. The proposed allowance of £40,000 per run bears no relation to the actual costs being faced in the London network.

194. The overall defect remediation programme was unknown in 2002, and therefore no allowance was set, now requires a funding of £10.7m.

3.9.3.2 Omission of workload which was not in 2005/06 baseline

a) Storage - Gasholder Painting

195. A detailed storage strategy was developed by NGG and communicated to PB Power during the narrative responses and cost visits. The strategy identifies those holders which will be required in the long-term and proposes an investment programme to maintain those holders and upgrade them to comply with recent legislation. This programme includes specific painting, working at heights compliance, essential mechanical repairs and upgrades, electrical upgrades to be compliant with legislation and improvements to cup water monitoring to maintain the safety of these systems. PB Power have not taken note of this detailed strategy and based their assumptions and the proposed allowances on inaccurate unit costs assumptions and simplistic workload drivers. This not only provides insufficient funding for gasholder maintenance, but also provides incentives to accelerate removal of gasholders from Networks in advance of the long-term cost optimum.

196. Gasholder painting is an essential maintenance activity for these long-lived assets. We broadly support PB Power's estimate of the cost to paint spiral guided and column guided holders per square meter as a reasonable attempt to take account of the significantly increased costs to paint the larger gasholders. However it is important that the required phasing of this work is properly considered.

197. The phasing of holder painting costs within the initial proposals is not reflective of the current condition of the gasholders. By phasing spend equally over thirteen years the proposals implicitly assume an equal spread of holder condition. The GDNs must address the condition of gasholders that actually exist rather than an idealised or simplified profile. Both NGG and the HSE emphasise the importance of an appropriate gasholder maintenance regime given the volumes of gas stored and their proximity to population centres.

198. An equal phasing of spend will lead to excessive deterioration and subsequent demolition of those gasholders that become a safety and environmental hazard. This will lead to capacity shortfalls. This is particularly true in the NW network where the spend profile set out in the

initial proposals would likely result in 51 gasholders having no appreciable remaining paint protection by 2012/13, and if this approach continued it is likely that approximately 50% of the gasholders in the Network would have been taken out of service by 2020.

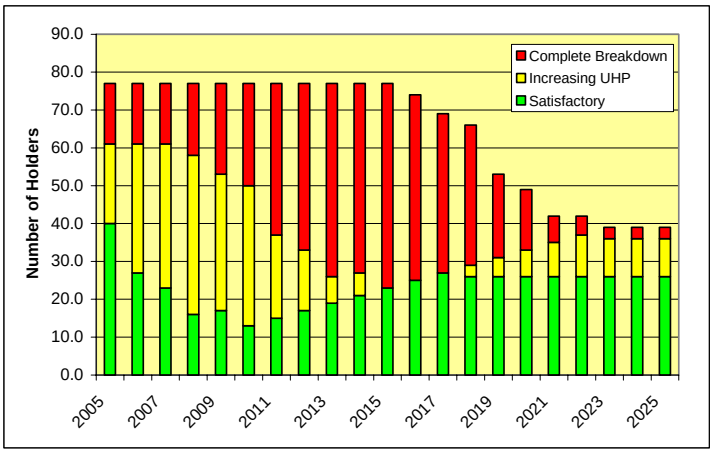


Figure 3.15 - Impact of gas-holder painting at a long-run rate in the North West

199. In other networks, such as East of England and London, which have a lower concentration of holders in need of painting it may be possible to manage broadly within a long-run rate allowance.

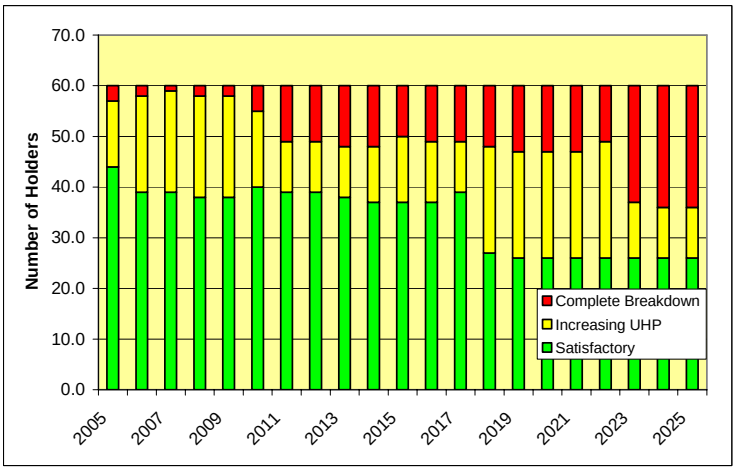


Figure 3.16 - Impact of gas-holder painting at a long-run rate in the London

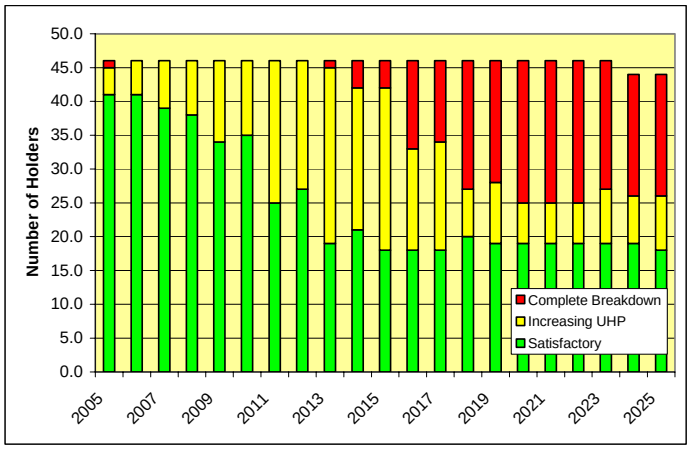


Figure 3.17 - Impact of gas-holder painting at a long-run rate in the East of England

200. NGG commissioned Advantica to complete independent holder condition assessments. These assessments review the level of paint breakdown and also the extent of corrosion and other required system maintenance. An example, Stretford Number 1, is provided below which forms part of the 2008/09 painting programme, similar reports can be provided for the remainder of the gasholder fleet.

Stretford 1 Condition Report

201. There is a risk that the proposal to fund a typical run-rate of holder painting will consistently underfund this activity. GDNs at the peak of the holder painting programme will be underfunded through averaging, whilst those in the trough of the programme would not request funding as it would not be required. There is therefore a significant risk that changes in funding methodology will result in underfunding of GDN's.

b) LTS

202. The requirements for LTS maintenance were justified during the price control process. By using simplistic drivers and assumptions PB Power have omitted significant expenditure from this long term investment programme and therefore recommended understated costs across the LTS system.

As a result of this approach the following programmes have been excluded:

- **OLI 1 Surveys**- NGG has over 5000km of pipeline operating at pressures above 7 bar which are required by legislation to be internally inspected at an expected cost of £8.7m over the review period. These inspections are periodic and the intervals are dependant on an algorithm which considers the presence of known defects and existing operating

regimes in place. The scheduling of OLI1 runs is known several years in advance and in figure 3.18 below.

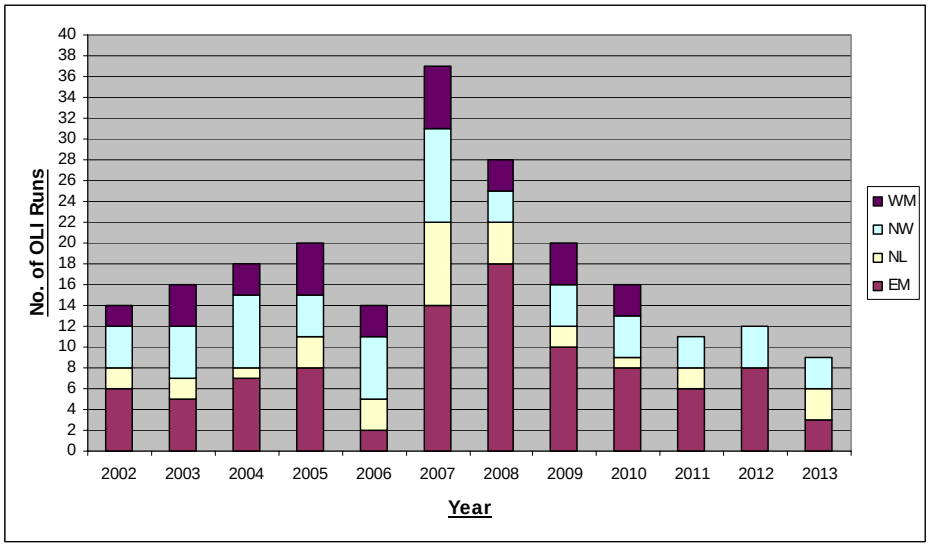


Figure 3.18 - OLI 1 survey schedule

The cost of an OLI run varies significantly based on diameter, length and access and eggress requirements. As can be seen in figure 3.19 below for the East of England programme it is not practical to project forward costs based on a single base year and 2005/06 and 2006/07 are significantly below average.

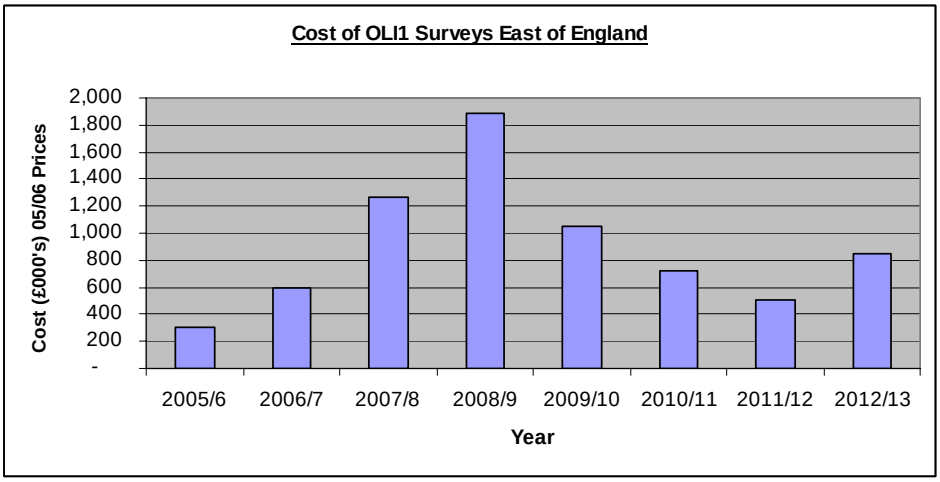


Figure 3.19 - Cost of OLI 1 surveys East of England

The use of a regression analysis and using 05/06 as an indicative year to set allowances for this activity is therefore inappropriate.

Whilst averaging across the four NGG networks reduces this effect, see figure 3.20, setting allowances without due regard to the required programme of works will result in arbitrary gains and losses for network operators.

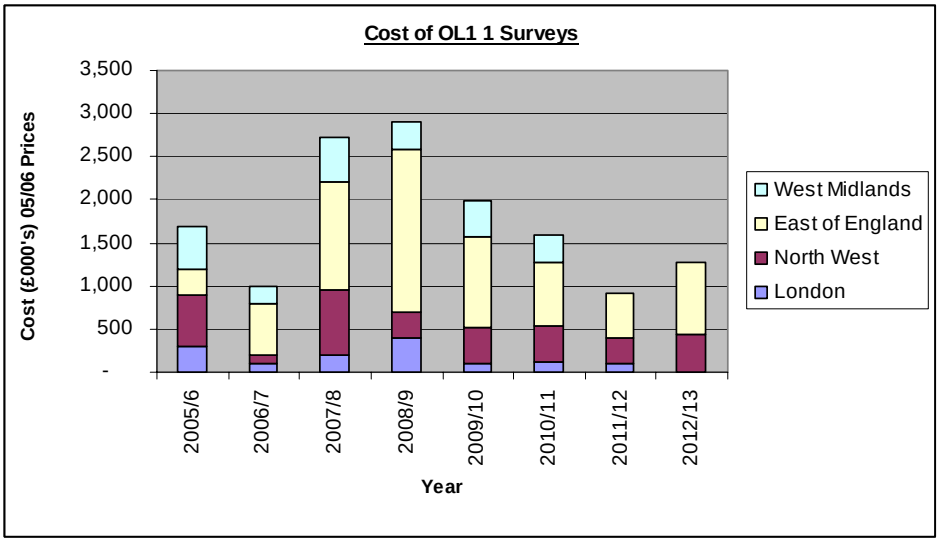


Figure 3.20 - Actual and forecast cost of OLI1 surveys

Deferral of this activity to match such an allowance is not possible and would undermine a key industry safety and legal requirement. The exclusion of funding for this activity would impact on the integrity management of these vital pipelines i.e. defects such as dents and corrosion which, if left unchecked, could potentially lead to failures of local transmission pipelines with severe consequences.

- **CP Remediation**- To ensure a high level of safety and reliability in operation, it is essential that buried steel pipe work associated with the high-pressure distribution of natural gas is able to withstand the potentially harmful effects of corrosion. Cathodic Protection is used to prevent and monitor this degradation. Following a detailed review in 2006/7 the need to upgrade and renew existing systems was verified. All existing CP systems were analysed by Advantica using a decision support tool to prioritise the workload. A total of 451 systems under existing policy (ECP/2) were deemed as non compliant with varying degrees of non conformance based on location, criticality, physical and operating characteristics as detailed below.

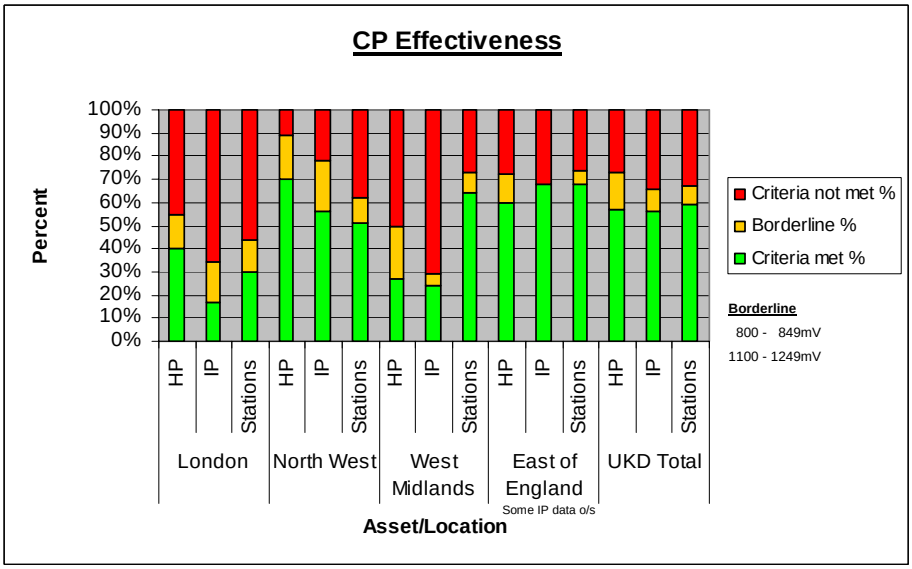


Figure 3.21 - CP Effectiveness

An agreed approach with the HSE was established in 2006/7 to ensure compliance to maintain acceptable safety levels for the networks over a period of 5 years to 2012/13. This essential plan of works has been excluded from the Initial Proposals as it was not part of the 05/06 baseline. The impact of disallowing the expenditure of this vital activity would result in further degradation of cathodic protection systems as ground potentials are not sufficient to maintain a corrosion barrier, leading to pipe wall corrosion and potentially failure, but more likely the replacement of the pipe at significant cost. In this financial year, £760k expenditure had been approved to remediate mainly high priority systems. The breakdown of this is as follows:

			Priority		
Network	**No of non compliant systems**	**Approved Expenditure (07/08)**	High	Med	Low
North West	102	£116,250	3	10	89
West Midlands	40	£121,000	16	14	10
East Midlands	172	£103,250	29	7	136
North London	52	£200,000	0	0	52
East Anglia	85	£221,000	65	9	11

Table 3.20 – remediation of high priority systems

- **Special Crossings**-NGG has approximately 2000 special crossings operating mainly at Medium Pressure, some of which are strategic feeds into conurbations. Surveys of crossings have highlighted areas of active corrosion on both the pipelines and their corresponding supports. An example of a degraded special crossing is a MP pipe crossing the river Don in South Sheffield shown below in Figure 3.22. The pipe acts a strategic feed into the town of Mexborough and failure would result in the isolation of supplies to 10,000 downstream consumers. The repair of this crossing requires the

reinstatement of supports, maintenance painting and revalidation (at a cost of £180k). NGG have developed a prioritised programme for identification of the highest risk crossings which takes into account operating pressure, location and criticality. Due to the prioritised focus on key risks, NGG plans to address some of our largest crossings in the most hazardous locations. At the requested levels of expenditure, c.£1m/annum for all four networks, it is probable that only a very small number of crossings, 1 per network, could be remediated. It is essential that such works to major crossings proceed at least this rate to control risks to third parties including major roads and railways as illustrated below in figure 3.23, which shows a crossing which is no longer resting on its supports over both railway and underground lines.

Figure 3.22 - Ferry Boat Lane canal and river crossing

Figure 3.23 - Sheepcote Road Rail and Underground Crossing

203. This issue has been excluded from the allowances set out in the initial proposals as it was not incurred in 2005/06 and therefore £5m of essential spend to protect our major roads and railways.

3.9.4 Other Direct

204. As in our review of the work management composite size variable, we are surprised that PB Power have used Km of pipe as the driver for other direct. This activity is an amalgam of costs associated with tools and equipment, odorant, easements, compensation costs for supply interruptions and reinstatement inspections. As such a better suited single driver for the overall best measure of size, is that of customers. Indeed, if you carried out the regression on customers, see the chart below, the regression gives an r^2 of 0.86, better than PB Powers 0.80 based on km.

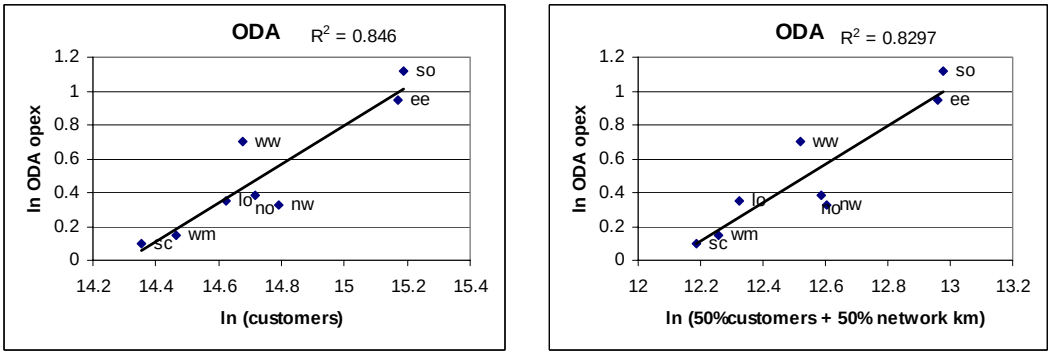


Figure 3.24 - Other direct activities regression analysis

205. Network length clearly and inappropriately disadvantages dense networks with high workloads i.e. London, which on PB Power's analysis of km was the most inefficient network.

206. Interestingly, Wales and the West is the least efficient on the customer measure. Using the Km driver, the gap is lower but this network is still above then median benchmark. As such it may be that some allowance for exogenous factors (dispersity) is required. NGG do not believe that this should just take the form of using some averaging of factors (i.e. as in the top-down analysis) as this does not give improved fit (the r^2 would fall to 0.82 using 50 : 50 customer : km driver), rather specific evidence / rationale for an exogenous factor – as NGG has supplied to Ofgem and PB Power on specific London factors.

3.9.5 xoserve

207. The proposed xoserve savings in operating expenditure are based on inappropriate comparisons with GDNs that do not take account of the different nature of the xoserve and GDN businesses. Whilst it is agreed that benchmarking should be carried out we feel it would be more appropriate to compare xoserve against externally validated benchmarks that are comparable.

208. xoserve IS costs have been benchmarked against GDNs which utilise a different set of systems to xoserve and has a completely different profile of projects and cost pressures. In fact the efficiency savings proposed are based on the costs of SGN whose activities are on marginal costs which creates an unsustainable benchmark.

209. xoserve Property costs are also derived on GDN benchmarks and no recognition has been made of the different nature of the businesses and the property requirements. LECG take no account of the data centre and office use in xoserve against the mixture of office and operational property operated by GDNs.

3.10 Further Work Areas

210. We note the issues that Ofgem still have to address, and look forward to working toward a satisfactory conclusion over the summer. It should be noted that these areas will all require appropriate funding and as such the stance currently taken by Ofgem, of zero allowance, will not be the case in the final proposals.

3.10.1 London Factors

211. Whilst Ofgem has taken into account the direct labour and contractor regional variations in the Initial Proposals, but as stated they have yet to consider the other exogenous factors highlighted by NGG, that need to be fully reflected in the analysis. The quantifiable exogenous costs currently not allowed for London are;

Factor	Activity	£m pa
Underground congestion and reinstatement/disposal costs. The highly congested nature of London's underground infrastructure causes excavations in London to be 46% larger than the average DN	Repair	2.7
24 Hour Society - emergency work profiles in London require operation of 24 hour shift patterns to ensure delivery of our regulatory obligations.	Emergency	0.5
The central London traffic congestion charge scheme is clearly an exogenous factor	Repair	0.3
Total		**3.5**

Table 3.21 - Excluded exogenous costs for London
London factors supporting information

212. National Grid has taken the opportunity to review the factors not currently allowed in the interim proposals in light of 2006/7 actuals.

a) Underground congestion and reinstatement/disposal costs

The highly congested nature of London's underground infrastructure causes excavations in London to be 35% larger in area and 8.5% deeper than the other 8 distribution networks, giving a 46% increase in volume.

DN	EM	EA	LO	NW	WM	SC	NO	WW	SO	AVE non LN
Average excavation (m^2)	1.34	1.39	1.83	1.36	1.30	1.38	1.40	1.31	1.33	1.35

Table 3.22 - Average excavation size for Operations activities (sample size 100 per DN[26])

DN	EM	EA	LO	NW	WM	SC	NO	WW	SO	AVE non LN
Average depth (m)	0.79	0.88	0.89	0.78	0.84	0.78	0.78	0.82	0.86	0.82

Table 3.23 - Average excavation depth (based on a sample size of 14,548 jobs[1])

The samples were constructed on a random basis:

- Area – length and width dimensions were not recoverable from our IS data warehouse and consequently a manual data trawl was undertaken to derive 100 jobs per DN, split by work type and diameter, i.e. for each DN the data set included 20 8" to 10" repair jobs.


Area.xls

The analysis shows that, on average, excavations in London are 35% larger in area than other NGG DNs.

- Depth – our data warehouse was able to extract depth data and consequently the data set was larger at 14,548.


Depth.xls

The analysis shows that, on average, excavations in London are 9% deeper than all other DNs.

[26] Data for all GDNs is from 2004/5.

The high levels of construction activity in the London area, e.g. London 2012, Terminal 5, and their limited availability (landfill sites and quarries located outside the M25) leads to the cost of reinstatement materials (sand, stone, bitumen and recycled) being 13.9% higher in London than other NGG networks.

	Noth West	West Midlands	East Midlands	East Anglia	North London
Sand	11.47	10.05	7.66	9.50	15.00
Stone	12.47	11.25	14.22	15.05	16.30
Bitumen	64.30	53.02	59.26	59.63	59.63
Recyclable Material	7.18	8.03	9.78	12.25	13.00

Table 3.24 - Reinstatement material costs

The analysis shows that, on average, materials in London are 16% higher than other NGG DNs.

In summary, this results in London's excavation, backfill and reinstatement costs being 70% higher, on a like for like basis, than other DNs.

Repair unit costs comprise of a number of subjective cost categories; materials, labour (direct, contractor, mixed) and reinstatement. The increase of 70% in costs described above apply to all these subjective costs except materials.

Using East Midlands as a representative unit cost (balance of urban/rural, diameter and labour mix) the financial impact of the increased excavation volume due to underground congestion on labour and reinstatement costs has been assessed. London's additional costs are not applicable to Interference related work as higher costs are recovered via higher income.

£/job	**Mains**	**Services**
Gross unit cost	683	38
Material costs (not affected)	95	7
Impacted unit cost	588	31
Uplift	70%	70%
Comparative unit cost	409	21

Table 3.25 - East Midlands Repair unit costs.

In 2006/7, London's condition repair workload was 6039 and 9667 for mains and services respectively. Applying the 'comparative unit costs' to this workload demonstrates that London's exogenous costs associated with underground congestion and increased reinstatement costs are £2.7m pa ((6039 x 409)+(21 x 9667))

London network has a higher proportion of large diameter mains than any other DN. Excavating on these mains requires additional excavation depth. This additional depth

requires additional costs associated with trench support, personal protection, safe control of operations, supervision and management. NGG has not quantified the financial impact of these elements.

The impact on BPQ activities is shown below.

BPQ Activity	£m (2005/6 prices)
Repair	2.4
Maintenance – Other	0.3
Total	**2.7**

Table 3.26 - Financial impact by BPQ activity

b) 24 hour society

The greater proliferation of the 24 hour society in London means that not only are emergency calls received throughout the 24 hour period, they are also greater in volume. To deliver our legislative and regulatory obligations our emergency workforce are employed to work a shift pattern covering 24/7/365 rather than the traditional extended day working supplemented by more expensive call out and overtime.

Figures 3.25 to 3.27 show actual workload profiles for a super urban (Central London), Urban (Hemel Hempstead) and a rural (North East Anglia) unit, demonstrating that both the volume of work and quantity received out of hours is significantly greater in London. Undertaking this work on a traditional overtime and call out basis would increase our costs base compared with shift working.

In addition our resource modelling indicates that using shifts to cover the work requires circa 100 FTE's less using shifts than using overtime and call out. This is an important additional consideration in ensuring we continue to deliver our regulatory obligations in an area characterised by a highly competitive and flexible labour market.

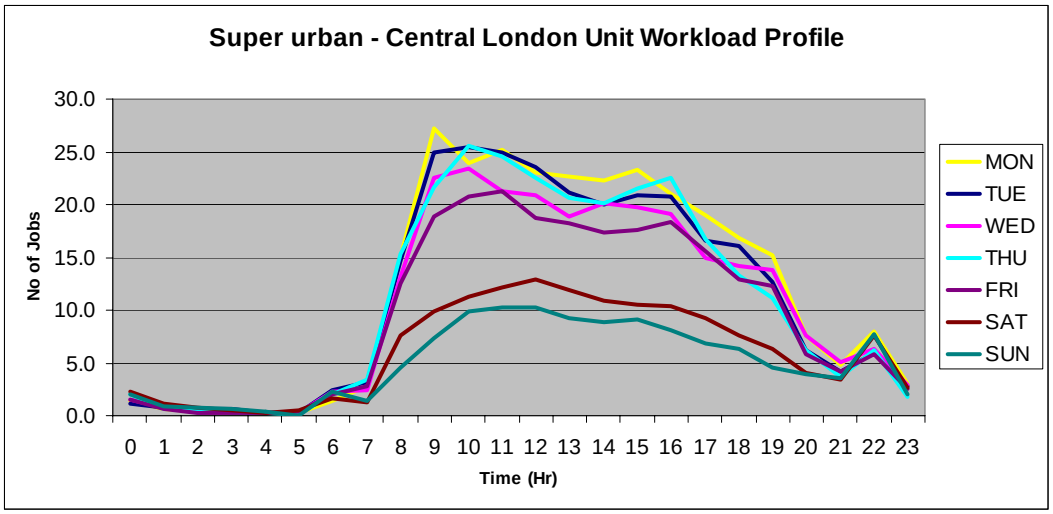


Figure 3.25 - Central London actual work profile

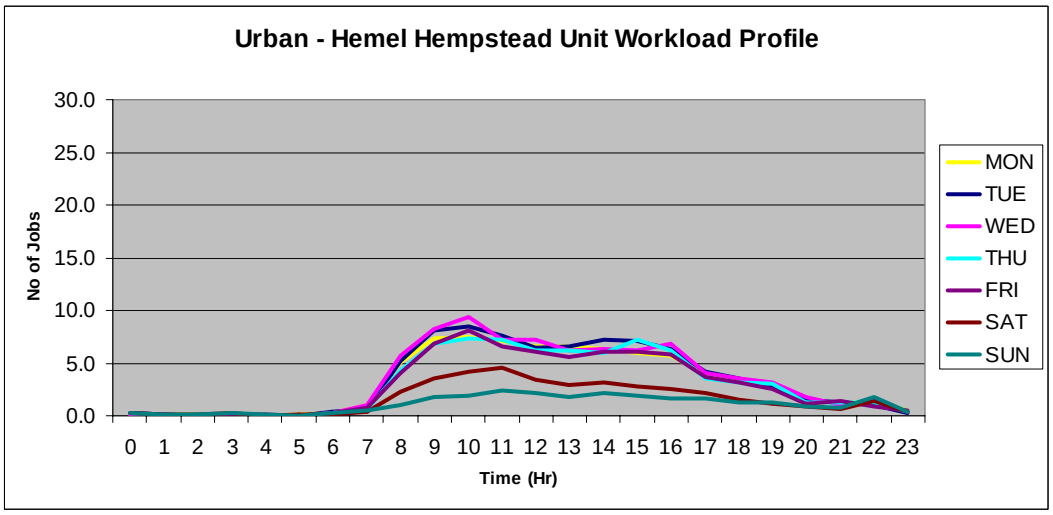


Figure 3.26 - Hemel Hempstead actual work profile

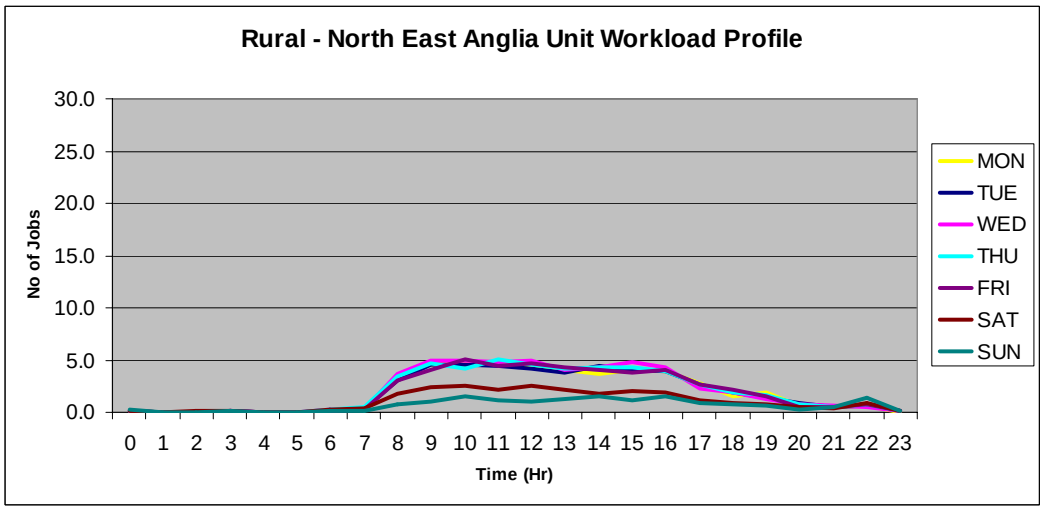


Figure 3.27 - North East Anglia actual work profile

NGG utilises 231 emergency engineers on shift patterns. These patterns attract a payment premium (£5,500 per annum) which is pensionable. At the current pension rate of 34.8% this equates to £0.5m per annum.

Despite the operation of shift patterns, a level of overtime is worked to cover unplanned peaks in workload and absence cover. NGG has not quantified this additional cost.

The impact on BPQ activities is shown below.

BPQ Activity	£m (2005/6 prices)
Emergency	0.5
Total	**0.5**

Table 3.27 - 24 Hour activity impact

c) Congestion Charge

The introduction of the congestion charge scheme (the only one in the country) has meant that in 2006/07 NGG incurred £94,000 of invoice costs. On 3/7/2005 the charge was raised from £8.

The enabling legislation allows the Mayor of London to expand the congestion charging zone and with effect from 19th February 2007 the area was expanded to over double the original size to include Kensington, Chelsea and Westminster (see Transport for London website www.london.gov.uk/mayor/congest/index.jsp). The implementation of the revised area late in our 2006/7 financial year and invoicing/payment delays means that our 2006/7 actual costs did not reflect the increased size of the zone. We anticipate our costs to be £0.2k in 2007/8.

The impact on NGG is disproportionate as the expanded area contains a greater proportion of domestic premises and therefore incursions. Going forward, NGG have minimised the impact of these associated costs by pre registering its vehicle fleet to obtain a discount of £1 per occasion.

Our Distribution Support and Shared Services organisations employ 2 FTEs (at £30,000 pa each) to manage the associated back office processes, i.e. invoice validation and payment,

In total London Congestion charging is anticipated to cost NGG £300,000 per annum for the review period (assuming no charge increase).

The impact on BPQ activities is shown below.

BPQ Activity	£m (2005/6 prices)
Work Management	0.05
Emergency	0.1
Repair	0.1
Maintenance – Other	0.05
Total	**0.3**

Table 3.28 - Congestion charge

213. It should be noted however that there are numerous other, un-quantified, factors in play in London, such as access difficulties, greater proportion of tarmaced surface area and complex underground infrastructure (including ducting), the significant number of additional Councils, traffic congestion, the location of plant in London subways, the number of below ground installations, and the additional restrictions of working in the capital.

214. These are examples of we believe PB Power included only a 70% gap closure, which a pragmatic and responsible approach to benchmarking, and would mitigate against underfunding what are ultimately safety-critical and mandatory activities.

3.10.2 Environmental remediation costs

215. Ofgem's reference to the costs of environmental remediation in the Initial Proposals document states that, in principle, they agree that allowance should be made for this activity and that further work will be necessary for the updated proposal to determine the appropriate level. We are however, surprised that only W&WU is mentioned. NGG made a provision against these costs directly in the BPQ cash flow statement and not explicitly in the opex tables. Detailed narrative responses were also submitted as part of our submission[27].

216. Over the next formula period, NGG's environmental programme is looking to spend £16.8m over the five years 2008/9 to 2012/13.

217. Ofgem will need to fund this necessary expenditure in the Updated Proposals. A fuller explanation of these costs follows.

218. Contaminated land provisions were inserted into Part 2a of the Environment Act (1995), although the provisions were well known for some time before, allowing the industry to prepare for it. Under the Act, local authorities (LA's) have been designated as the front line environmental regulator (although the Environment Agency can take over in cases of serious

[27] NGGD Main BPQ Supporting narrative, October 2006, question 6.180

groundwater pollution). LA's have a duty to inspect their areas and to identify potentially contaminated land against a statutory definition. This has provided a very significant driver on businesses, including NGG, to investigate its land and develop programmes of remediation to manage land that has the potential to be identified as contaminated under the Act. Within the circumstances supported by the Act, it is advantageous for a landowner to proactively manage any potential liabilities, as action under enforcement conditions results in the loss of certain tax breaks and therefore adds to the overall cost of dealing with the contamination.

219. Most major businesses have now recognised that they have a social duty to operate their businesses in a responsible manner (backed by financial drivers based on green investment decisions). It would not be considered to be acceptable for a company of the size and reputation of National Grid to only act when forced to do so under direct threat of environmental prosecution. This has driven investment in the management and remediation of contaminated land, from screening and site investigation to the implementation of a risk based prioritised strategy that has been reviewed by the Environment Agency. It is important to recognise that the contamination arises from historic operation of the sites as manufactured gas plants and is not as a result of current operational activities.

220. The contaminated land programme is managed on National Grid's behalf by National Grid Property (NGP) and ensures that potential impacts are minimised through an active remediation programme, which reduces the risk of action under EPA Part 2a and other environmental regulations. NGP are also contracted to the four independent gas distribution networks to provide similar strategic and site specific management services. NGP are widely acknowledged experts in this field and employ an in house dedicated professional team and external supply chain to ensure that expenditure is managed and specifically targeted at mitigating environmental risks to ensure that sites are fit for their current use. Where land becomes surplus and additional works are required to change the end use, the costs are separately accounted for and do not fall within the identified provision. HMRC have recently completed an audit of the programme for tax purposes and have concluded that the whole spend was qualifying land remediation expenditure.

221. Expenditure against the provision between 2001/2 and the end of 2006/7 was £35.2m. NGG intends to invest a further £16.8m in further contaminated land remediation over the next formula period 2008/9 to 2012/13, in a planned programme that includes an allowance for emergency works as a result of pollution incidents or pressure from environmental regulators to deal with sites outside of the planned programme.

£m, 05/6 prices	2008/9	2009/10	2010/11	2011/12	2012/13
East of England	0.9	1.0	1.3	0.5	0.5
London	0.9	1.0	1.3	0.5	0.5
North West	0.9	1.0	1.3	0.5	0.5
West Midlands	0.9	1.0	1.3	0.5	0.5

Table 3.29 - Environmental Remediation Costs

222. It is not possible to fully identify in which of the networks the money will be spent as environmental priorities evolve with time. However, the current split in the 2007/8 financial year is East (£135k); North London (£455k); North West (£2.24m) and West Midlands (£70k). £200k has been allocated across all networks in 2007/8 for the development of Risk Management Plans. The RMPs will be used to identify emergency works and to allocate spend in future programme years.

223. The project summary below illustrates that, although enforcement notices have not been served, there is pressure from environmental regulators to deal with the sites. In this particular example, a remediation cost in relation to NGG land of £1.034m was incurred over the period June 1997 to June 2007. Across the National Grid portfolio in 2006/7 enquiries were received from environmental regulators in relation to historic contamination matters on 27 ex-gasworks sites.

- **Summary example – Desborough Road, High Wycombe** The site was originally used for gas manufacturing dating back to 1867. The total site area is 1.43 hectares and is jointly owned by NGG (0.51 ha) and NGP (0.92 ha).The site was originally a gasworks and was latterly a depot and operational gasholder and gas governor site.

  Offsite pump tests undertaken in 1992 for Thames Water identified trace concentrations of gasworks contamination (phenols) in the abstracted groundwater at the Pann Mill Pumping Station located 800 m, ESE down gradient of the site. Pann Mill is the Public Water supply borehole providing drinking water to High Wycombe. In addition to Thames Water, the Local Authority and the Environment Agency became aware of the conditions on the site and together the three stakeholders began to exert pressure for action to be taken to address the environmental risks present at the site.

  The site was extensively investigated between 1997 and 2001 and was ranked as a high priority in the Environmental Prioritisation Model managed by NGP on behalf of NGG. The site investigations showed that on site sources of contamination

presented significant risks to the public water supply, the River Wye and the Chalk Aquifer beneath the site.

Following consultations with the key stakeholders a strategy was agreed to develop an acceptable remediation design. The remediation that was agreed was for a combined approach of excavation, soil washing and bioremediation for phase 1 and possible groundwater treatment for phase 2. All works were to be undertaken taking into account the sensitive environmental setting and having appropriate controls in place.

Phase 1 works were completed successfully between January 2005 and March 2006 and have been signed off by the Regulators. Further requirements for Phase 2 are currently being considered following further investigations and groundwater treatment pilot studies.

3.10.3 Loss of Meterwork

224. NGG welcomes Ofgem's recognition that loss of meterwork, from their current levels, will increase waiting time and hence the net costs in providing the emergency service. We are looking forward to receiving Ofgem's updated work on this area. We have already submitted details results from our workload manpower match models that indicate the impact on our costbase given the minimum manpower levels required to provide the required emergency standards.

225. PB Power have completed an initial review of the impacts, for which we have two key comments

a) As well as the impact on direct emergency costs accepted by PB Power, Ofgem will also need to make an allowance for the adverse impact on indirect costs. Although not fully fixed, these support costs, e.g. IS support our field force, and so cannot be reduced. For instance, currently the IT systems support costs for field force are attributed to both meterwork and emergency; they still require this system and the hardware in the vans to run emergency activity. As such more costs will be required to be allowed for in the regulatory costbase as meterwork declines.

b) It was asserted that additional infill work could be found to partially offset the fall in meterwork. We would contest this given the issues of skills. However, if a level of additional infill was targeted Ofgem would have to make an additional allowance for training and continued competency assessment costs.

3.10.4 Waste management

226. We are please to note that Ofgem have identified the issue of waste management as an area of further work, particularly as PB Power had made an arbitrary assumption on the impact in their draft reports for direct opex and investment.

227. Ofgem will need to reflect the revised costs of landfill tax, updated in the last Chancellors Budget, and also the impact of tightening compliance with legislation and directives.

3.10.5 Apprentices and Training

228. In our submission we are seeking c£10m pa in Apprentice and training costs across our four networks which covers:

- Apprentice costs include the training and salary costs of the necessary apprentices needed to replace natural wastage of our aging workforce (i.e. number of retirements is increasing).
- Training costs for all of our 2150 field force is for mandatory technical training requirements to ensure continuing and demonstrable competence.

These are necessary costs that will need funding. In paragraph 6.27 of the Initial Proposals, it states “we also note that GDNs have supported separate funding for areas such as skills and training and research and development”. NGG does not support this stance for the basic requirement of a core level of apprentices and the continual training requirements of our skilled workforce which should be part of the basic opex allowance.

However, there is a case for consideration of a separate funding initiative, similar to the IFI initiative to research and development to mitigate the emerging workforce cliff face that is facing the industry in the formula period after next, i.e. post 20012/13. The low level of recruitment over the last fifteen years has been one factor that has driven down operating costs, to the benefit of the customer. This has, however, resulted in a high, and increasing, average worker age, as shown in figure below.

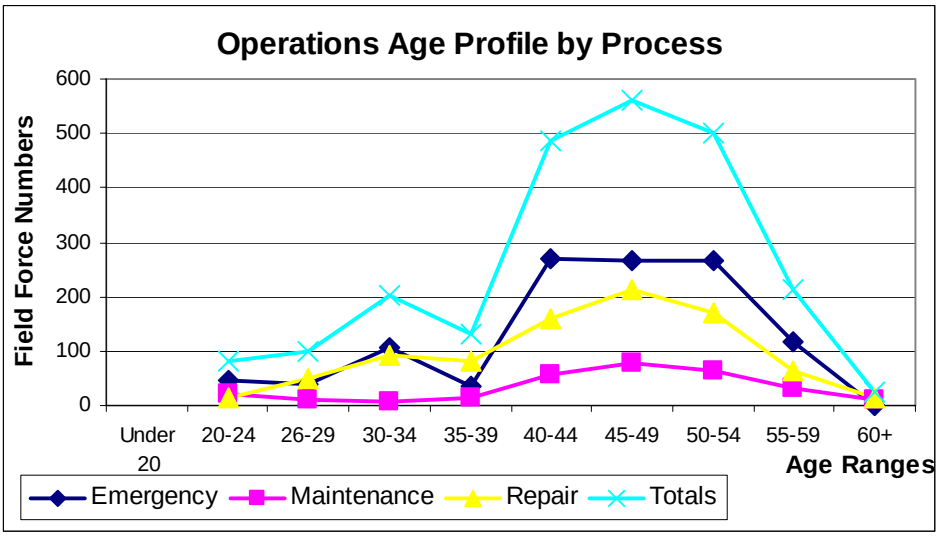


Figure 3.28 – Operations age profile by process

Without positive action this period to address a resource cliff face in the period after next the industry will be facing both a cost efficiency and skills shortfall as the number of retirees increases significantly.

3.10.6 CO Monitoring

229. Our position on this is discussed in respect to our answer to question 3 of this chapter of the Initial Proposals.

3.10.7 Traffic Management Act

230. The traffic management act is due to come in with the recent announcement that changes to notices, directions and the introduction of fixed penalties will be effective from 1st April 2008. This will bring about additional administration and operating costs in addition to the costs of permit fees and fixed penalty fees. Ofgem will need to provide allowance for an efficient level of fines given that the complexity and re-active nature of much of our work in the carriageway, the additional administration and field resources to deliver 100% compliance would not be economical. NGG has submitted information early on in the review process that indicates that the expected cost of the traffic management act will be around £3.6m pa for each of our four networks. Note, this is the opex costs, only there will also be costs associated with repex and capex.

3.10.8 Pensions

231. National Grid welcome Ofgem's confirmation of their established principles to allow full recovery of actuarially recommended pension costs. As highlighted to Ofgem (Mark Cox) in a letter dated 2 July, National Grid are planning to provide an update to the current pension cost data to reflect the results of the ongoing March 2007 valuation.

232. With respect to Ofgem's proposed work on the treatment of "stranded surpluses", National Grid wish to highlight the importance of ensuring aligned thinking between Ofgem and the Pensions Regulator in this regard.

Chapter Four - Capital and Replacement Expenditure Analysis

Questions 1 & 2: Do you agree with our approach for setting investment (capex and repex) allowances and the proposed allowances we have derived using that approach?

233. This section provides further detailed analysis and evidence regarding the issues summarised in section 2. The areas covered are:

4.1 Real Price Effects;
4.2 Downsizing of Mains Laid;
4.3 Productivity;
4.4 Other Workload Adjustments, specifically the proportion of services transferred and abandon to lay; and
4.5 Modelling Issues including notional values, regional factors and the allocation of connections capex to market sectors.

4.1 Real Price Effects

234. As explained in section 2, fully updating our methodology for calculating a forecast for contractor real price effects results in a national average of RPI+3.08% and a London rate of RPI+4.75%. The attached spreadsheet provides the data supporting these calculations.


OFGEMBaxterECHv5
.xls

4.2 Downsizing of Mains Laid

235. Typically, when designing mains replacement schemes we look to replace existing iron mains with the largest new main size that can be inserted within the existing carrying pipe in order to minimise cost and maintain system capacity, and our BPQ submission reflected this approach.

236. Mains insertion and other minimisation of excavation techniques are a key focus within National Grid. Across our four networks we are currently achieving 92% of mains replacement work using no-dig techniques thereby minimising costs, disruption to the public and reducing the impacts to traffic flows, whilst at the same time maximising productivity.

237. Ofgem's Initial Proposals assume that a fixed proportion of mains can be laid in the smallest diameter band (<=75mm) within each GDN (North West and West Midlands 30%, East of England 25% and London 12.5%), based primarily on a review of historical levels.

238. These historical levels are not representative of the future, given the skewed downwards diameter mix of mains decommissioned during the period 2002/3 to 2006/7, as illustrated in Figure 4.1 below.

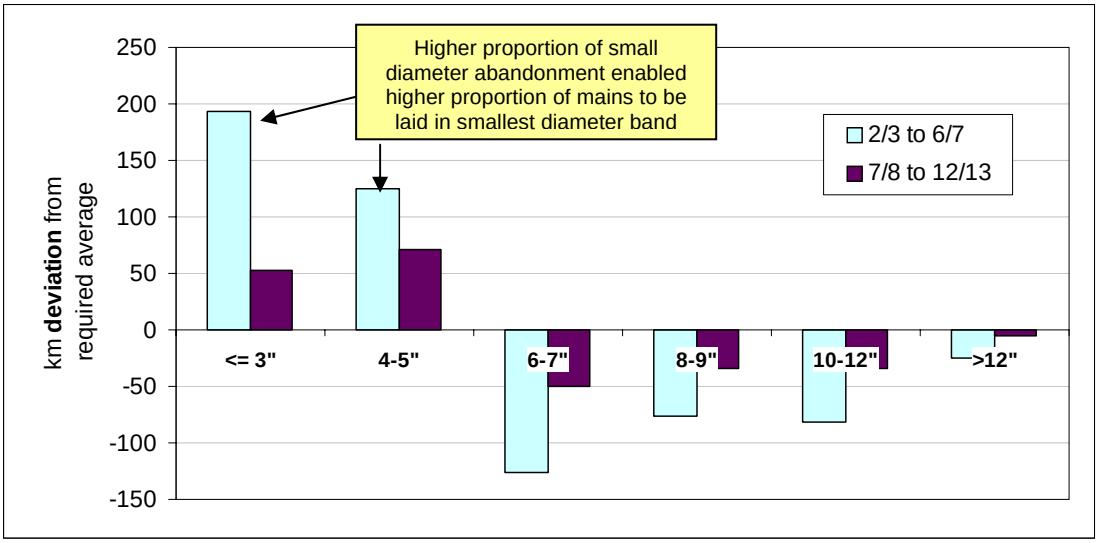


Figure 4.1 - Deviation of Decommissioning Lengths from Average Based on Population

239. NGG has achieved considerable reductions in risk profiles during the initial part of the HSE policy mains replacement programme where the highest risk mains, due to their close proximity to property and greater likelihood of fracture, were predominantly within the smallest diameter bands. Maximum use of available pressures was made in replacing these mains resulting in higher levels of downsizing being experienced than can now be achieved, as load has grown within the networks and 'spare' capacity is used.

240. To presume that similar levels of downsizing can automatically be achieved going forward fails to recognise the fairly profound changes in the diameter mix of mains to be decommissioned over the next price control period, where we expect to replace mains that are, on average, 13% larger than those replaced last period. The planned diameter mix of work is more representative of the remaining population of iron mains and includes a significantly higher proportion of larger diameter mains. Consequently, the diameter mix of mains laid will be larger than historically.

4.2.1 Network Analysis

241. Notwithstanding the above, we have reviewed the network analysis modelling for a representative sample of specific projects to be started in 2008/9 in order to assess the implications of applying Ofgem's assumption of laying a fixed proportion of mains in the smallest diameter.

242. It should be noted that significant pressure improvements can be gained by laying 90mm as against 75mm. 75mm would typically show an increase in pressure drop of 240% for the same flow, illustrating the criticality to network design of 'downsizing'.

243. The projects selected relate to either post code sectors or small/medium sized towns that would be completed within the price control period and are some of the largest networks where work is planned to start in 2008/9. (Generally, larger schemes would give greater opportunities for downsizing thereby producing the best opportunity to meet Ofgem's proposed profile of mains laid).

Table 4.1 below provides summary results of the network analysis modelling relating to two local networks in each GDN, with attached presentation material giving further detailed network design and analysis information. The length of iron main associated with these schemes is equivalent to 75% of the typical annual HSE policy workload for NGG.

GDN	Network	Iron mains (km)	Ofgem Downsizing %	Actual Downsizing %	BPQ %	Design & Network Analysis Information
East of England	Grimsby	201	25%	17.5%	17%	Grimsby.ppt
	Grantham	48		20.2%		Grantham.ppt
North West	Morecambe	221	30%	19.5%	24%	Morecambe.ppt
	Buxton	34		19.7%		Buxton.ppt
West Midlands	Rugby	145	30%	15.9%	18%	Rugby.ppt
	Hereford	103		22.8%		Hereford.ppt
London	Southend	472	12.5%	4.1%	10%	Southend.ppt
	Bracknell	213		8.8%		Bracknell.ppt

Table 4.1 – Network Analysis Modelling Results

244. In all cases, system pressures fell below the minimum required to maintain supplies. To restore system pressures either reinforcement would be required (additional capex) or the level of mains laid in the smallest diameter would need to be reduced and larger pipes laid. The examples demonstrate that the proportion of mains laid in the smallest diameter band would need to be reduced broadly in line with the planning assumptions used for our BPQ submission.

245. Ofgem's fixed proportion approach, proposed by PB Power, does not address the operational, environmental and inconvenience to customers impacts that would be caused on the upstream network and does not allow NGG to run a safe network or to deliver a minimum operating pressure of 21mbar to comply with Gas Safety Management Regulations to maintain adequate pressure at the consumer's appliance as incorporated in our Safety Case.

246. The relationship of smaller diameters to larger diameters is critical in this respect and therefore, it is totally inappropriate to assume that increasing the proportion of mains laid in the smallest band could be accommodated by proportionally reducing the lengths laid in all the diameter bands above.

Consequently, this proposed adjustment to our BPQ submission should be removed.

4.2.2 Network Analysis Example - Grimsby

247. This section walks through the network analysis that has been undertaken using the Grimsby network in East of England as a typical example of the projects we have reviewed (as identified in Table 4.1 above). Each presentation pack in Table 4.1 follows exactly the same format:

- Network background and proposed approach to achieve Ofgem's proportion of mains laid in the smallest diameter band;
- The location of the iron mains to be downsized;
- The implications for system pressures, leaving all other mains in the network untouched;
- The location of the remaining mains to be replaced using the largest diameter that can be inserted into the carrying pipe;
- The implications for system pressures;
- The necessary adjustments to achieve system balance; and
- A summary of the analysis.

248. The Grimsby network is a mixed material system containing 201km of iron mains and is operated at 47mbar to 50mbar.

Figure 4.2 highlights in blue the mains to be laid in the smallest diameter band to achieve the required level of 25% for East of England. This requires all 3" and 4" mains together with a proportion of the 6" mains in the network to be laid <=75mm pipe.

Figure 4.2 – Grimsby Network – Mains to be Laid in <=75mm Shown in Blue

Figure 4.3 shows that system pressures in parts of the network fall below the minimum of 21mbar required (highlighted in yellow) when 25% of mains are replaced in <=75mm with all other mains left untouched.

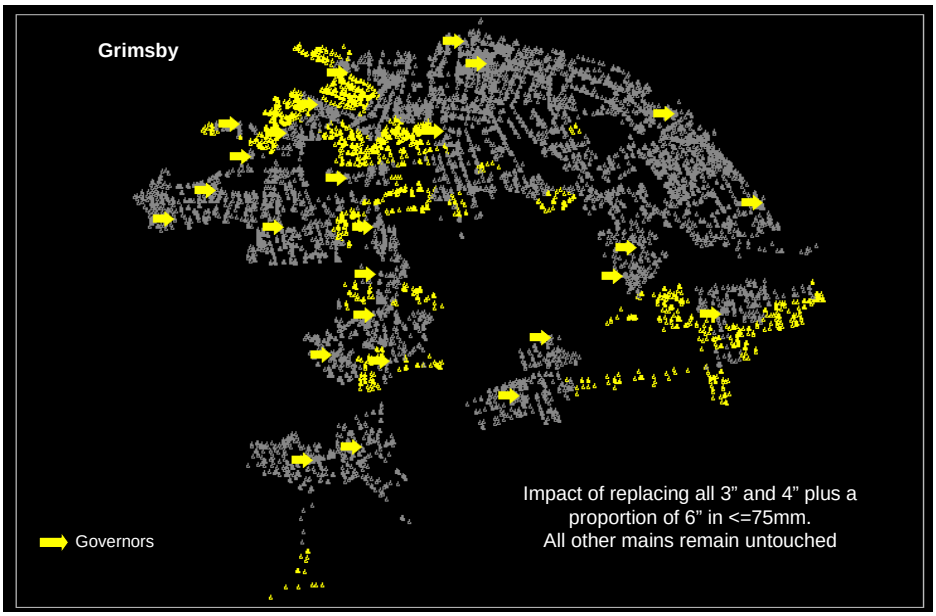


Figure 4.3 – Grimsby Network – System Failure Highlighted in Yellow

249. The next step in the process is to replace the remaining iron mains by insertion using the largest diameter pipe that can be inserted in the existing carrying main in order to minimise costs. These pipes are highlighted in green in Figure 4.4 below.

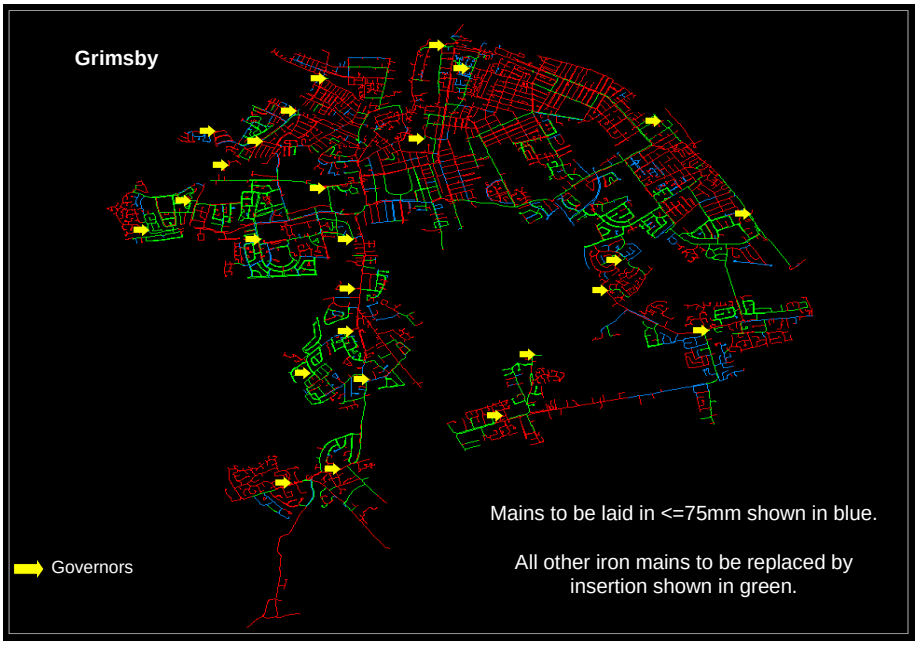


Figure 4.4 – Grimsby Network – Remaining Pipes to be Replaced Shown in Green

It can be seen from Figure 4.5 below that system pressures fall below 21mbar in further areas of the network causing widespread system failure.

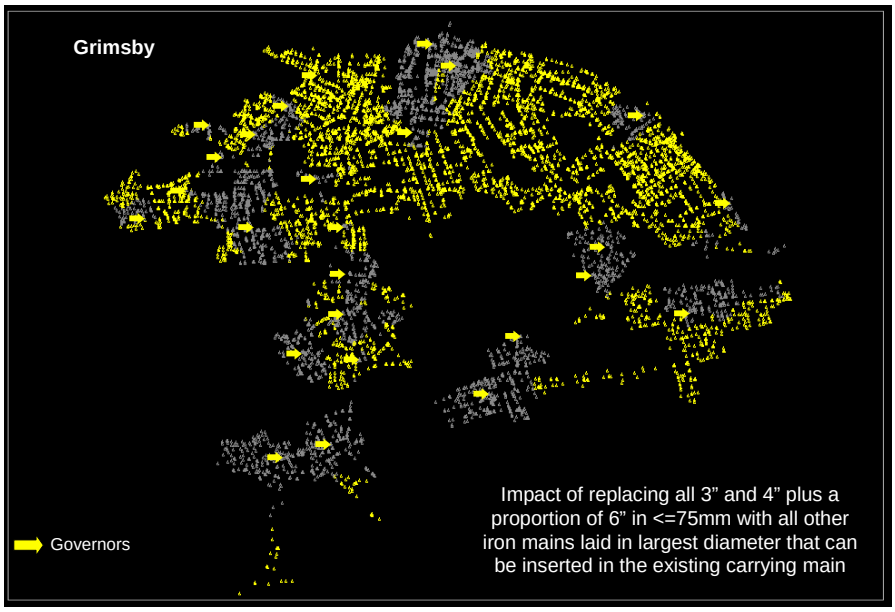


Figure 4.5 – Grimsby Network – System Failure Highlighted in Yellow

250. Clearly it is possible to upsize mains to recover network pressures. This could be done for the larger diameter, high flow mains or alternatively at the smaller diameters. With the smaller diameters alternative minimisation of excavation techniques are open to us, namely moling and pipe bursting. Upsizing the smaller diameter mains is the optimum solution, in order to recover system pressures, avoiding the need for costly open cut techniques.

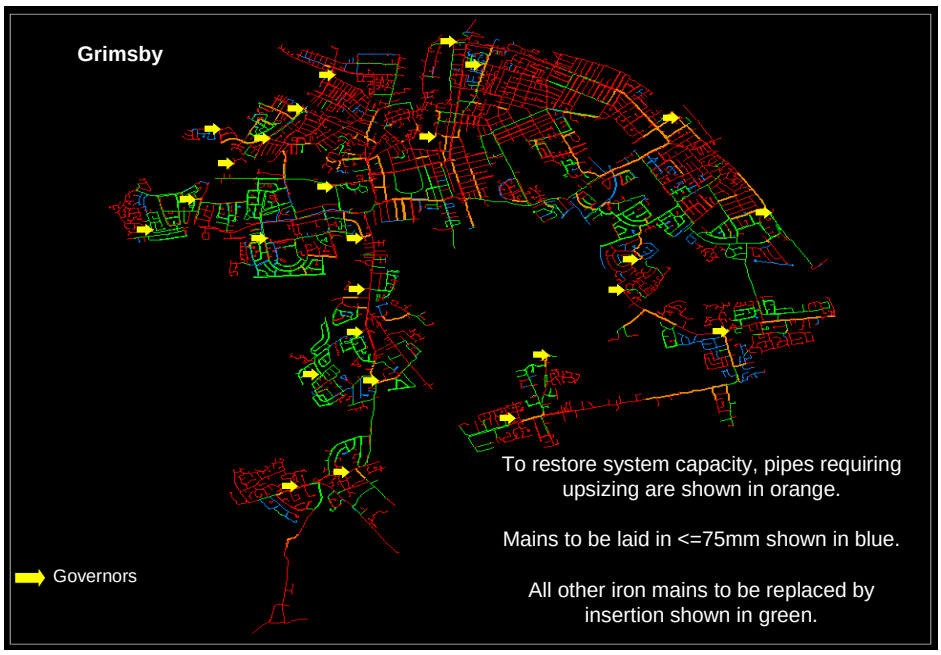


Figure 4.6 – Grimsby Network – Upsized Mains Shown in Orange

Figure 4.6 shows the pipes that need to be upsized/reinforced in order to restore system balance (a total of 21km identified in orange). This removes 16km of mains from the <=75mm band reducing the percentage in the bottom band from 25.5% to 17.5%. This compares well with the 17% in our BPQ forecast for the whole network in 2008/9.

Reinforcing the system, particularly the larger diameters to increase pressures at the extremities could be considered. However, this would require additional capex that is not included within our BPQ submission.

4.3 Productivity

251. Ofgem's assumptions for on-going efficiency are largely without credible substantiation and, in many cases, are wholly unrealistic.

252. PB Power has reviewed information published by National Statistics and OFWAT indicating average rates of productivity improvement in the range 1.7%-2.0%. However, much of this productivity improvement will be captured via RPI.

253. Importantly within the utility sector, the increasing levels of legislation (e.g. environmental and Traffic Management Act) together with the increasing use of the highways by traffic users and other utility companies combine to build in constraints which are tending to decrease productivity year-on-year. Whilst we have no hard data to show the effects of this, it is considered to be much like traffic flows where average journey times are increasing.

254. PB Power state that they have used a base annual increase in productivity of 1% and have then used their engineering experience and judgement to determine where they believe there is scope for additional productivity above the base rate. These areas are provided in Table 2-6 of the published capex/repex reports, with the scope for productivity improvements indicated by the number of ticks in a range of columns relating to new techniques, labour productivity, clerical support, process improvements, contractual reductions and IS improvements. No further evidence is provided to justify the number of ticks or the definition of the columns. This is not a sound and robust basis for assessing the potential for productivity improvements which ultimately drive the proposed allowances. Ofgem has, in some cases, then increased the assumption for annual productivity improvements.

Specific comments relating to connections, reinforcement and repex are provided in the following sections.

4.3.1 Connections

255. Table 4.2 below is an extract from Table 2-6 from PB Power's reports on capex/repex and indicates PB Power's assessment of the scope for productivity improvements above a base rate of 1% - the more ticks in a column, the greater the potential scope.

256. PB Power's proposal, supported by Ofgem, is for year-on-year productivity improvements of 3% (higher than the assumption for mains replacement). It is inconceivable that greater productivity can be achieved in this area than for high volume, largely geographically concentrated mains replacement work which has longer planning times, etc. compared with a mature connections activity, with its rigorous standards of service regime, where jobs are one-off in nature and geographically dispersed.

257. The proposed allowances for connections represent an average 28% reduction for our networks compared to our October BPQ, despite no adjustments having being made to workloads. This includes a remarkable 22% reduction for West Midlands, which was shown to be the frontier network based on PB Power's regression analysis.

258. As noted in section 2, it is remarkable to believe that in a market that has been opened up to competition for a number of years still has inefficiency in the region of 20% still to be removed.

PB Power View		**Potential Opportunities (above base productivity)**					
Activity	Rate	New Techniques	Labour Productivity	Clerical Support Costs	Process Improvements	Contractual Reductions	IS Improvements
Connections	3%	✓	✓✓	✓✓✓	✓✓✓	✓✓	✓✓

Table 4.2 – PB Power's View of the Scope for Productivity Improvements in Connections

259. The 3% productivity assumption has been applied to all connections activities. Any implications on gross connections spend relating to new housing and non-domestic work would largely flow through to changes in customer contributions as the vast majority of this work is funded directly by the customer requesting a connection. Therefore, the most significant impact on net capex would be seen in existing housing where NGG is obliged to give a domestic load connection allowance for new customers within 23metres of a relevant main.

We have reviewed PB Power's tick box approach and make the following comments.

New Techniques

260. Existing housing connections are relatively simple in terms of construction. Over 95% consist of a new small diameter PE service pipe (usually <=32mm) with a simple top tee connection onto the existing main, usually located in the adjacent footpath and terminating at a meter box or house entry tee. The technologies currently in use have been developed over many years and include moling, with minimal excavation in the highway, and the use of PE pipe and fittings with quick and simple jointing techniques. There is, therefore, very limited scope for new techniques in this activity.

Labour Productivity

261. This is constrained by the geographic dispersion of the work which drives a premium from contractors. In addition, seasonal and short term changes in customer demand impact on the management of resources.

262. We have moved away from skilled/skilled teams to skilled/unskilled to reduce costs by using skilled labour for excavation/construction work and unskilled or contract labour for follow up reinstatement works. Furthermore, we are committed to keeping customer lead times to a reasonable level (around 4 weeks) and to hit promised dates. With this in mind we struggle to see how further improvements can be made.

Clerical Support Costs & Process Improvements

263. Costs are incurred in these areas as a result of various statutory and service standard obligations that impose necessary processes to manage NRSWA, license conditions, standards of service, health and safety requirements and asset records. These requirements must be delivered whist managing seasonal and often short term changes in workloads.

264. As PB Power acknowledges, we have made significant organisational improvements, through centralising and insourcing all support activities in Northampton through The Way Ahead and savings through the formation of Shared Services (benefits which were included within our October BPQ). It should also be noted that this is in the context of NGG delivering all year end standards of service in 2006/7.

265. We have implemented an 'intelligent' work scheduling tool that recognises the travel time, work type and job time for all jobs. These parameters are matched to teams and work mixes issued to maximise productivity of the teams within a day.

266. By insourcing the existing housing activity, similarly to labour productivity, we have combined some support activities to accommodate the peaks and troughs in workload and drive overall efficiency for connections work and also in other work-streams that we administer in Northampton.

267. Work scheduling now utilises 'batching' of work in geographies in remote locations given the removal of the previous D+15 standard of service. Customers are now given realistic dates that are met.

There is some scope for further improvement by combining some additional activities.

Contractual Resources

268. In anticipation of bringing the work in-house, contractors were asked to tender for the work as part of the TERM contract negotiations prior to 2005/6. The result was a 6% reduction in rates compared to equivalent Fulcrum rates and this has been built into our BPQ submission through the use of 2006/7 rates as the base for our modelling.

IS Improvements

269. We have already delivered efficiencies here by utilising Quarterback. There is limited scope for further efficiencies beyond that built into our BPQ.

Summary

270. Table 4.3 summarises NGG's view of the scope for productivity improvements in connections.

NGG View		**Potential Opportunities (above base productivity)**					
Activity	Rate	New Techniques	Labour Productivity	Clerical Support Costs	Process Improvements	Contractual Reductions	IS Improvements
Connections	1.3%			✓	✓		✓

Table 4.3 – NGG's View of the Scope for Productivity Improvements in Connections

4.3.2 Reinforcement

271. For mains reinforcement PB Power has suggested that the same levels of productivity can be achieved as for *major* mains replacement. They consider, for example, that there is more scope for new techniques in this area than for mains replacement or new connections work, but provide no examples to support this belief.

272. As stated in our response to the fourth consultation document, unlike mains replacement, mains reinforcement projects tend to be much smaller in size, often in discreet locations on the network. As such, the productivity improvements achieved on mains replacement through planning longer project lengths, limiting the movement of engineering teams etc, are not available.

273. More importantly, a significant driver of productivity within mains replacement is the level of insertion (c90% for NGG's networks). Given the fact that for reinforcement, new and additional mains are being laid to increase system capacity, this technique is seldom available for mains reinforcement.

4.3.3 Repex

274. For repex we had assumed on-going annual net efficiency improvements of 4% in 2007/8 falling to 1% a year from 2009/10, although in the West Midlands network, the frontier network, we had assumed 1% a year. Our assumptions reflected the remaining

improvements that we anticipated could be achieved from our Alliance contracting approach, the impact of a shift to a zonal approach to the selection of mains to be decommissioned, whilst recognising the significant use of no-dig techniques already being achieved (over 90% in 2006/7). It should be noted that this productivity is additional to the economy-wide productivity built in to RPI. PB Power assumed that 0.75% additional productivity above its base assumption of 1% could be achieved by all GDNs, including the most efficient, by virtue of a tick in each column (2 ticks for contractual reductions).

275. Ofgem has then increased this assumption to 2% with no additional substantiation provided. This needs to be viewed in the context of the implications of Ofgem's downsizing assumptions which, if implemented, would reduce the level of productivity achievable due to the need to lay a higher proportion of mains by open cut techniques.

4.4 Other Workload Related Adjustments

4.4.1 Proportion of Services Transferred

276. PB Power has adjusted the forecast proportion of services to be transferred rather than relaid in East of England and London based, primarily, on historical trends. Table 4.4 provides information relating to the last five years for East of England and London.

Proportion of Services Transferred						2008/9 to 2012/13	
	2002/3	2003/4	2004/5	2005/6	2006/7	BPQ	Initial Proposals
EoE	54%	50%	59%	56%	57%	46%	55%
London	46%	43%	43%	46%	42%	41%	45%

Table 4.4 – Proportion of Services Transferred

277. The ratio of service relays to transfers is influenced by the specific nature of the networks being worked upon at the time. Prior to the outset of the current HSE policy mains replacement programme, networks were undertaking targeted bulk renewal of services. Consequently, when policy mains replacement is subsequently undertaken in the same area the proportion of services transferred to relaid will be much higher than in areas where bulk service renewal has not previously been done.

278. Within East of England a lot of work has been undertaken over the last few years within Derby where a ratio of 30% relays to 70% transfers was achieved. Historically, Derby has been an area of extensive redevelopment with significant numbers of council house renovation schemes leading to many services being renewed, hence the high proportion of transfers during mains replacement work. By 2007/08 we will have moved out of Derby and anticipate

a return to more "normal" levels of service transfers consistent with our planning assumption of 55% relays to 45% transfers.

279. Similar geographic trends apply to London, particularly given the diverse nature of the Network from inner city to leafy suburb.

4.4.2 Abandon to Lay

280. Ofgem has reduced the length of mains to be laid for a given length of mains to be decommissioned by applying an abandon to lay ratio of 1.05:1. This ratio is higher than forecast by NGG, and higher than actually achieved by NGG over the last two years, and ignores the progressive increases in the use of insertion techniques over the last five years which are consistent with a declining abandon to lay ratio and lower overall project costs. This is consistent with the properties of the supplementary incentive mechanism via which GDNs are encouraged to achieve the lowest overall cost for abandonment.

281. Table 4.5 below provides a comparison of actual abandon to lay ratios for NGG with the proportion of mains decommissioned by no-dig techniques (insertion rate). As the insertion rate has increased, so the abandon to lay ratio has fallen.

Year	Ratio	Comment	Insertion Rate
2002/3	1.13	MPDI	52%
2003/4	1.23	Peak year for network rationalisation and influence of EPC rate levers	70%
2004/5	1.12	End of Asset / Ops and EPC contracts.	73%
2005/6	1.03	Increased use of insertion techniques.	85%
2006/7	1.03	End of ramp-up. Sustainable level.	92%

Table 4.5 – Abandon to Lay and Insertion Rates

282. NGG now delivers over 90% of workload through the use of no-dig techniques, the most cost effective and environmentally friendly method of mains replacement. Forcing higher abandonment ratios would give rise to the following key consequences:

- NGG will be required to deliberately increase the proportion of mains laid by open cut techniques by, for example, installing mains of larger diameter in order to replace two existing pipes either side of the road. This will result in higher unit costs, increased environmental impacts and further inconvenience to the public and highway authorities;

- Lower productivity, thereby slowing the programme;

- With the introduction of the Traffic Management Act (TMA), the duration of the works will be crucial in terms of noticing and liabilities. Open cut techniques have less certainty in this regard due to the unpredictable ground conditions and congestion of other underground apparatus;

- As the number of services en-route are generally covered by the full extent of the existing mains, laying a single main on one side of the road, to replace two existing mains in order to achieve a higher abandon to lay ratio, will increase the length and cost of services, some of which will need to be laid across the road as implied in the first consequence above;

- The first and third points above also give rise to greater risk for operatives to injury through damage to underground apparatus (e.g. cable strikes). It is a key safety objective for NGG to minimise such instances and lost time injuries (LTIs).

283. Maximising the use of insertion techniques, consistent with an abandon to lay ratio much closer to parity, seeks to mitigate many of these risks, and at reduced overall cost from which customers benefit.

284. Ofgem should remove this adjustment, returning the abandon to lay ratio for NGG's networks to the planned level of around 1.03.

4.5 Modelling Issues

285. Whilst we are broadly supportive of Ofgem's various methodologies for setting investment allowances, including the appropriate use of regression analysis as a method for assessing relative performance across GDNs, we have concerns in a number of areas:

- The use of notional values to evaluate the workload drivers in the regression analysis for repex which distorts both the overall allowance and, more significantly, the subsequent allocation of the recommended allowance to activities (see 4.5.1). This issue also impacts on mains reinforcement and connections;

- The allocation of proposed allowances for gross connections capex to market sectors based on notional values which gives perverse results and the subsequent allocation of this to net capex (see 4.5.2);

- The regional factors for East of England which currently do not take account of the impact of work undertaken in Outer Met and, therefore, distorts the regression analysis and subsequent allowances (see 4.5.3);

- The removal of the glide path and the presumption that a GDN can make fundamental changes to systems, processes and contracts by April 2008 (see 4.5.4); and

- The benchmarking of other operational capex which takes no account of the relative size of GDNs resulting in inappropriate allowances (see 4.5.5).

286. In the light of the above, we do not believe that sufficient sense checking has been undertaken of the results of the various regression analyses (see 4.5.6 for further illustrations).

287. The following proposed actions are required prior to the September Update:

Issue Area	**Proposed Actions**
Notional Values	• Explain the derivation of the notional values for each regression analysis • Test the robustness of the results by using different values e.g. actual GDN rates for the 1st, 4th and 8th GDNs • Ensure that any subsequent breakdown of the recommended allowance to activities (e.g. repex mains and services) is sensible.
Connections	• In addition to the notional values actions • Use GDN percentages to split recommended gross to market sectors • Use GDN percentages of net to gross for each market sector
Regional Factors	• Apply Outer Met adjusted regional factor for East of England when undertaking updated analysis based on 2006/7 actuals
Glide Path	• Allow glide path to 2010/11
Other Operational Capex	• Correct errors relating to West Midlands and London • Revise land & buildings target to reflect supply points

Table 4.6 – Issue Areas and Proposed Actions

4.5.1 Notional Values

288. A fundamental aspect of the regression analysis that has been undertaken for repex, connections and mains reinforcement is the use of notional values applied to workload to derive a synthetic cost driver.

289. The relationship of these notional unit values to a GDN's actual unit costs has a distorting effect on the regression analysis and therefore, the allowances Ofgem has calculated. The notional values also influence the split of allowances by activity thereby further distorting the allowances. This is certainly the case for repex as outlined below.

290. The net repex allowance is, fundamentally, the result of regression analysis undertaken at overall net repex level on a base year rolled forward using Ofgem's assumptions for productivity and real price effects. It might have been expected, therefore, that any efficiency recommendations arising from this analysis would then have been applied equally to mains and services. However, this is not the case.

291. For NGG's 4 networks, Ofgem is proposing an average reduction in net repex of 13% from the normalised BPQ submission, with mains expenditure reduced, on average, by 9% but services expenditure reduced by 21%. Given the fact that minimal workload adjustments have been proposed for services (and for North West and West Midlands networks **no** workload adjustments are proposed), it is inconceivable that services expenditure should be reduced to a greater extent than for mains, where workload adjustments have been made for all networks (abandon to lay ratio and downsizing of mains laid). Moreover, the work is undertaken by the same contractors under the same management teams in the same geographies implying a similar level of efficient operation.

292. The adjustments made to our normalised BPQ submission are as follows:

- Reduction to mains lengths laid (abandon to lay ratio) – impact must relate solely to mains;

- Increased proportion of mains laid in the smallest diameter band with a consequent reduction in the mains lengths in all other diameter band. Again, the financial impact of this adjustment must relate solely to mains;

- A change in the proportion of services to be transferred rather than relaid in both East of England and London networks – impact must relate solely to services; and

- Efficiency and price assumptions (productivity, real prices and regional factors). The financial impact of these adjustments would equally affect mains and services.

293. Table 4.7 provides a trace between the normalised BPQ submission and the initial proposals using the spreadsheet provided by Ofgem on 25 June 2007 and shows that mains repex has been reduced by 9% whilst services repex has been reduced by 21%.

NGG **£m, 2005/6 prices**	**Mains**	**Services** **(incl. risers)**	**Total**
Normalised BPQ	1,257	585	1,842
Workload adjustments	(83)	(10)	(93)
Efficiency adjustments	(25)	(114)	(149)
Initial Proposals	1,139	461	1,600
% difference	(9%)	(21%)	(13%)

Figures may not cast due to rounding

Table 4.7 – Ofgem's Proposed Reductions to Repex

294. The split of the overall efficiency adjustment is totally perverse (i.e. a 3% reduction to mains but a 19.5% reduction to services) and is driven by the notional values used to evaluate the repex workload driver.

295. Whilst the above is clearly an error which must be addressed before the September update, we believe that the notional unit values could distort the underlying regression analysis results. We have attempted to test the sensitivity of the results to different notional values but without the integrated model containing the data for all 8 GDNs, we are unable to fully validate this. However, our limited testing suggests that, for example, increasing the notional unit value for mains >630mm from £400 to £500 could increase NGG's overall net repex allowance by >£5m. By contrast, increasing the notional value of a service transfer from £147 to £200 could result in a reduction in the allowance of around £15m.

296. We are concerned that the proposed allowances could be materially incorrect if the results of these limited tests are accurate.

297. Ofgem should:

- explain the derivation of the notional values used within the regression analysis;

- test the robustness of the results by using differing values for example based on actual rates for a selection of GDNs (e.g. 1st, 4th, 8th); and

- Ensure that any subsequent breakdown of recommended values to activities (e.g. repex mains and services) is sensible.

4.5.2 Connections

298. We have serious concerns regarding the analysis undertaken for connections activities. No workload adjustments have been proposed for NGG's four networks and yet the net capex allowance is, on average, 28% lower than our BPQ submission. Given the issues with the connections overspend during the last five year control the scale of adjustment is mystifying. Even the frontier network, based on the regression analysis undertaken on 2006/7 forecast data (West Midlands), is subject to a 22% reduction without any workload adjustments. To suggest that there is such a level of inefficiency in this activity across the industry is remarkable, particularly given the competitive nature of the new housing and non-domestic market sectors.

299. The scale of the proposed reduction may, however, simply be the result of fundamental flaws in the approach.

300. The connections regression analysis has been undertaken at a gross cost level for total connections. The workload driver has been evaluated using notional unit values (the source of which is unknown) and these unit values have then been used to split the gross costs between the three market sectors of new housing, existing housing and non-domestic. We believe the notional values radically distort this split of gross capex and may also distort the overall regression analysis in a similar way to repex (see Section 4.5.1 above).

301. For example, Table 4.8 provides a comparison of the average percentage split of gross connections capex for North West for the period 2008/9 to 2012/13 between the BPQ submission and PB Power's recommendation, subsequently adopted by Ofgem in its Initial Proposals, based on notional unit values.

% of Gross Capex	New Housing	Existing Housing	Non-Domestic
BPQ Submission	45	36	19
PB Power	41	41	18

Table 4.8 – Average Percentage Split of Gross Capex by Market Sector

302. Therefore, whilst PB Power has reduced overall gross spend in North West by £14.8m (18%), the table shows that PB Power's methodology results in a significant shift in the split of gross capex between new housing (reduced by 26%) and existing housing (reduced by 8%).

303. Changes in gross costs should ultimately flow through to customer contributions. As stated in our charging methodology statement, we aim to recover those costs that we reasonably expect to incur in providing our connection services and, therefore, our charges should track, as far as possible, both upward and downward movements in gross costs.

304. Consequently, any distortion in the split of gross capex to market sectors, resulting from the use of notional values, will automatically flow through to net capex, despite using the GDNs own figures for moving from gross to net capex.

305. PB Power then applies a standard set of assumptions to all GDNs to move from gross spend to net. Based on these assumptions, net capex for new housing in North West is **increased** by 25% over the five years compared to our BPQ submission despite the 26% reduction in gross capex.

306. Ofgem has correctly discounted PB Power's standard set of assumptions to move from gross to net capex, considering it "appropriate to use the GDNs own figures for net capex as a percentage of gross capex and then apply these to PB Power's gross capex figures". However, we are unable to reconcile the percentages used by Ofgem with those submitted in our October BPQ. In all cases, the percentage applied to existing housing is materially lower than our BPQ submission.

307. NGG has undertaken a high level impact analysis on our four GDNs by applying the BPQ split of gross costs by market sector to Ofgem's proposed gross costs and then applying the BPQ percentages of net capex to gross capex. In undertaking this work we have sought to replicate Ofgem's calculations using PB Power's spreadsheets. However, as can be seen from column (a) in Table 4.9 below, we have been unable to fully replicate the results (£84.7m calculated compared with £83.9m published – column (c)). However, this does not invalidate the conclusions we make.

Net Capex £m, 2005/6 prices	**Initial Proposals Gross Capex(*) using:**		**Initial Proposals as published**
	Ofgem split to markets and gross to net (a)	**GDN split to markets and GDN gross to net (b)**	**(c)**
North West	14.6	16.8	14.4
East of England	33.9	33.2	33.2
West Midlands	14.1	14.6	13.7
London	22.1	22.7	22.6
NGG Total	**84.7**	**87.4**	**83.9**

(*) replicated by NGG using PB Power's spreadsheets adjusted for Ofgem changes e.g. glide path, gross to net.

Table 4.9 – Net Connections Capex

308. Applying the GDNs split of gross capex by market sector to Ofgem's recommended gross capex and using the GDN percentages to move from gross to net capex results in a higher level of net capex than proposed by Ofgem, with material differences in North West and West Midlands.

309. The attached spreadsheet provides further detail on our impact analysis.


Connections analysis.xls

310. The following actions are required prior to the September Update:

- explain the derivation of the notional values used within the regression analysis;
- test the robustness of the results by using differing values for example based on actual rates for a selection of GDNs (e.g. 1st, 4th, 8th);
- split the recommended gross capex to market sectors using GDNs own percentage splits; and
- use the GDNs own figures for net capex as a percentage of gross capex by market sector.

4.5.3 Regional Factors – Outer Met

311. Ofgem's Initial Proposals made some allowance for the higher labour (i.e. contractor and direct labour) rates associated with operating in London, as shown in Table 4.10.

Index	WW	NO	SC	SO	EoE	Lon	NW	WM
Initial Proposals	0.96	0.96	0.96	1.07	0.96	1.16	0.96	0.96

Table 4.10 - Ofgem Regional Factors in GDPCR Initial Proposals

312. The Outer Met area is part of East of England for allowed revenue purposes but is operationally part of the London network. The operating costs, assets and liabilities of the area can reasonably be estimated based on the number of supply points - in effect 9% of the London Network. The proportion of capital and replacement work in the Outer Met area on the other hand can vary, depending on the specific work programme undertaken. Our October BPQ submission assumed the following:

- Specific LTS and reinforcement projects within the Outer Met area would be included within the East of England submission. However, over the period 2008/9 to 2012/13 no such projects were identified;

- All other capex was subject to the 9% assumption; and

- All repex workload was specifically identified for the Outer Met area (equivalent to around 11% of London workload over the period 2008/9 to 2012/13) and included within the East of England submission. This work is primarily undertaken by our North London Gas Alliance.

313. Taking account of these assumptions, including the actual proportion of repex work planned for the Outer Met area over the five years, and applying Ofgem's regional factors of 0.96 for East of England and 1.16 for London, gives an **Outer Met adjusted factor for East of England of 0.98** (i.e. 1412/1338 in Table 4.11 below):

£m, 2005/6 prices	**EoE (excl. Outer Met)**	**Outer Met**	**EoE (incl. Outer Met)**
Opex	647	48	695
Capex	213	10	223
Repex	478	52	530
Total Costs	1338	110	1448
Outer Met Adjusted Factor	0.96	1.16	**0.98**
Adjusted for Regional Factor	1284	128	1412

Table 4.11 - Outer Met Adjusted Regional Factor for East of England

314. This revised factor should be used by Ofgem when updating its regression analysis using 2006/7 actual data.

4.5.4 Removal of Glide Path

315. Ofgem has chosen to ignore its consultant's recommendations regarding the closure of any gap between the upper quartile target performance and the GDNs forecast performance. PB Power had recommended a glide path to 70% gap closure by 2012/13, whereas Ofgem proposes that 100% gap closure must be achieved in less than a year i.e. by 1 April 2008, the start of the next price control.

316. PB Power's approach recognises both the potential inaccuracies in the regression analysis approach and the time required to make fundamental changes to systems, contracts and practices, many of which will require negotiation and approval with external bodies e.g. HSE, contracts etc.

317. Restoration of a glide path, for example, to the mid-year of the price control, would allow some recognition for the above issues.

4.5.5 Other Operational Capex

318. Other operational capex includes expenditure associated with pressure management equipment, IP/MP valves and land and buildings.

319. Ofgem's proposed reductions in this area relate primarily to land and buildings and reflects PB Power's application of an arbitrary benchmark of £1.5m per GDN over the five year period based on the upper quartile forecasts for seven GDNs (having discounted the lowest spend GDN). From the information available to us, it is unclear whether one of NGG's GDNs influences the upper quartile.

320. Our forecasts in this area reflect necessary investment (£7.5m) in our operational offices (primarily at Warwick, Hinckley and Northampton) that support all four GDNs. In our BPQ submission we allocated these costs to GDN's using supply points which resulted in a higher proportion of the costs being allocated to the larger GDNs, North West and East of England. These GDNs, therefore, received an allocation greater than the £1.5m benchmark whilst West Midlands and London received an allocation below the target. Had we allocated the centrally incurred costs equally to each GDN, each GDN would have received an allocation of £1.875m. This could impact on the calculation of the upper quartile target.

321. Notwithstanding this, PB Power's approach would have resulted in an allowance of £6m (i.e. £1.5m x 4) for NGG compared with the proposed allowance of £5.2m (any GDN forecast spend below £1.5m is not adjusted up to the benchmark).

322. Our allocation, based on supply points, took some account of the relative size of GDNs which PB Power's approach (equal amounts) does not.

323. Furthermore, we believe there is an error impacting on the proposals for West Midlands and London networks, whereby £0.3m of expenditure in each network has been disallowed even though the forecast spend was less than £1.5m and specific statements within the PB Power reports confirm that no adjustment (other than RPEs) has been applied. The difference in assumptions for RPEs is insufficient to explain the scale of adjustments applied to West Midlands and London.

324. Ofgem should take account of these issues and increase the proposed allowances for NGG's networks accordingly.

4.5.6 Sense Checks

325. Analysis of the proposed matrix values for mains and services repex suggests that appropriate sense checks may not have been completed. The graphs in Figure 4.7 below indicate the positions and movements over the period relative to North of England's rates.

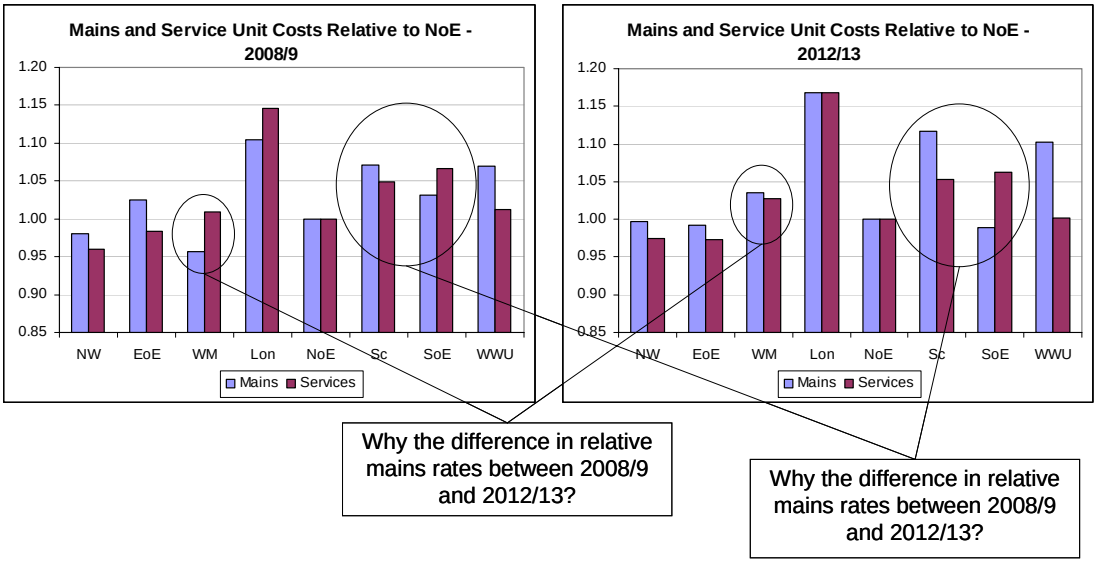


Figure 4.7 – Repex Mains and Services Matrix Values

326. Given the regional factors applied by Ofgem in its analysis (e.g. 1.16 for London and 0.96 for North of England), a differential in mains and service rates of around 20% between London and North of England might have been expected, particularly given the fact that all GDNs below the upper quartile must have achieved upper quartile performance by the start of 2008/9. However, the graphs show that London's mains rates in 2008/9 are only c.10% higher than North of England's, whilst the services rates are c.15% higher. It is unclear why there should be a differential in rates between mains and services.

327. By contrast, the relative rates for London in 2012/13 appear more logical – i.e. the differential in rates is the same for mains and services - although they still fall short of the 20% differential.

328. Figure 4.7 also indicates that Scotland and Wales and West networks have the second and third highest rates after London. The rationale for this is unclear. One might have expected South of England's rates to have been second highest given the regional factors of 1.09 for contractor costs and 1.07 for direct labour. In fact, by 2012/13, South of England's mains matrix values are the lowest for all GDN's

329. Further potential anomalies include:

- West Midlands mains values are lower than service values relative to North of England in 2008/9;

- There is a significant change in the rates for SGN's two GDNs in 2012/13 compared with 2008/9.

330. Further work is clearly required to ensure that the mains and services values are both robust and sensible across the GDNs. There is a risk of potential distortions to the contracting market if there are significant differences in rates between neighbouring GDNs which could put the achievement of HSE policy mains work at risk.

Chapter Five – Outputs

Question 1: Do you support our proposals for changes to the outputs and quality of service arrangements?

331. As stated in section 2 we are concerned that the amendments, as they stand, may lead to disproportionate levels of financial penalty or inappropriate automatic Licence breach. Detailed below is additional information on our key concerns in support of the points raised in section 2.

5.1 Changes to Outputs and Quality of Service Arrangements

5.1.1 Replacement of the Overall Standards of Performance with Licence Conditions

332. Whilst we take the quality of our service seriously, it is important to recognise that failure of many of the standards may arise as result of extreme circumstances that are beyond the control of the GDN, for example severe weather conditions or a number of large 3rd party caused incidents coinciding. In this regard the text of section 33BA(3) of the Gas Act provides the appropriate test "it shall be the duty of every gas transporter to conduct his business in such a way as can reasonably be expected to lead to his achieving the standards set out under this section" [Ofgem should have due regard to the intent of primary legislation when transferring the standards originally put in place under this legislation into licence.] The drafting of the Licence condition should afford the GDN and Ofgem similar safeguards provided that the GDN has taken all reasonable steps to meet the requirements. If necessary, a reporting and escalation process could be inserted within the Licence, whereby the licensee provides a written explanation in the event of failure to meet the required standard, with Ofgem able to impose improvement notices on the licensee **if required**. The licence breach would continue to be the ultimate sanction should the performance not improve.

5.1.2 Transfer of Overall Standards to Guaranteed Standards

333. In respect of the complaint standard we recognise Ofgem's simplification of this measure by moving to a 10 day response and the £20 compensation payment should the required level of service not be achieved which is in line with the water industry standards. However, we do not support the proposal to introduce additional payments beyond the 10 day response period particularly as the Consumers, Estate Agent and Redress arrangements have only just started to be consulted on by Ofgem and the DBERR and the interaction between complaint standards and any new statutory requirement will not become clear until 2008.

5.1.3 Changes to the guaranteed standards of performance

Supply restoration

334. We recognise that in bringing together the existing GS1 Supply restoration regime and the Third Party Water Ingress (TWPI) arrangements and including payments to IGT sites, the process is simplified and ensures all customers affected are compensated. In principle we support this change and the separate reporting of TPWI incidents to be appropriate.

335. There are a number of complexities associated with the proposed change that need to be considered prior to the implementation. As an example, IGT's must provide the supply point data to the GDNs so that they are able to pay the appropriate compensation within the time limits set within the other standards. Otherwise the GDNs may be exposed to additional GS12 payments (Notification and payments under the guaranteed standards) for reasons beyond their control. We would welcome the opportunity to work with Ofgem and other parties to resolve this and other issues.

336. We would like Ofgem to confirm that should a TPWI incident on an IGT's network result in a loss of supply to customers on a GDN's network, the IGT will be liable for the failure to supply payments.

337. Whilst GDNs currently provide emergency services to IGTs and therefore have a degree of control over resource allocation, the provision of such services is contestable and due for re-tendering by IGTs within the forthcoming price control period. It is important for Ofgem to note that should an IGT decide to have their emergency services provided by another party, the GDNs may be liable for compensations payment, without any ability to influence the speed with which consumers can be reconnected. If this scenario occurred, the GDN should not be exposed to the uncontrolled risk of excessive compensation payments associated with the operation of another pipeline system.

338. The changes proposed by Ofgem make a number of requirements within the UNC redundant (J 3.52). These requirements should be removed as the process of licence drafting is completed.

Reinstatement

339. We support the proposal to reduce the time frame for completion of private reinstatement from 10 workings days to 5 working days and appreciate Ofgem's proposal to include exemptions in relation to specialist surfaces where appropriate. In order to ensure that compensation payments do not become excessive Ofgem should introduce a cap to this standard of £250 per domestic customer and £500 per non-domestic customer which is consistent with the caps applied to other guaranteed standards of service, for example in relation to connections.

Alternative heating and cooking facilities

340. We agree with Ofgem's decision not to convert this standard to a licence condition because of the difficulties in capturing the associated data and level of performance already achieved by National Grid. However, the requirement to provide heating and cooking equipment should be restricted to consumers on the PSR rather than 'anybody that requests them'. Ofgem appear to have misunderstood our current practice in this area – though we provide alternative heating or cooking to more than PSR customers based on an assessment of need at the time of the incident, this is not the same as 'anybody who requests them'. As we have previously explained to Ofgem increasing the number of customers who are provided alternative heating and cooking would risk significant increases in the local electricity demand tripping local circuits. Further to this, extending the requirement will result in significant additional logistics costs to the GDNs and in the event of a large incident may result in the priority customers not getting the facilities that they need. Therefore, Ofgem's proposal is flawed and appears to be based on a misunderstanding of current practice. The focus should rightly remain on protecting vulnerable customers and widening the obligation could put this objective at risk.

Connections guaranteed standards of performance

341. We support the proposed changes to the Connections standards of service. Whilst we agree with Ofgem's assessment of the historical connections regime, since the lifting of the Enforcement Order in May 2005 National Grid has performed consistently well in meeting the new connections standards of service. However, the existence of the standards of service under Standard Special Condition D10 has no bearing on that performance, as customers receive compensation for failure directly through the guaranteed and voluntary schemes, both of which are reported to Ofgem on a quarterly basis. The D10 standards merely add an unnecessary layer of duplication that runs counter to the Authority's aims and objectives in relation to the Better Regulation principles, described in the Ofgem Corporate Strategy and Plan 2007 – 2012

5.1.4 Other Changes to the Outputs and Quality of Service Arrangements

Expanding GDNs' quarterly customer satisfactions surveys

342. We agree that expanding GDNs quarterly customer satisfaction surveys provides useful feedback to GDNs on how they carry out their services to customers and is an effective way of assessing the GDNs' performance in certain areas. Further work needs to be undertaken on the surveys that Ofgem are proposing as some of the wording of the questions is misleading and requires additional detail in order to ensure clarity on what is being measured. In addition, they may overlap with the existing surveys that the GDNs already undertake (for example the surveys following a repair job). We believe that the standards of service working group would be an appropriate forum in which to further develop the surveys and review the questions in the existing customer satisfactions surveys.

Balanced Scorecard

343. We support the proposal of introducing a balanced scorecard across a number of measures because it provides an improved measure of the GDNs' performance which we believe consumers and other industry participants will find useful. We support the inclusion of the majority of metrics that Ofgem have identified. However we have the following specific comments:

- We do not believe that the measures of accuracy pipeline records are appropriate because they do not accurately reflect the GDN's performance. Please refer to our response with the respect to pipeline accuracy for further comment about the metrics included within the balanced score card.
- We do not proactively capture the number of reinstatements that are completed within standard because we do not believe it to be an efficient use of resources. Failure to meet this standard is reviewed on a reactive basis when a customer raises a query. As a result we would have to provide reinstatement data on this basis.
- Measurement of leakage is based on statistical analysis, which although provides a good representation of leakage behaviour, does not accurately reflect changes in losses year on year. As a result we do not believe that this is an appropriate measure to include in the balance score card.

5.1.5 GDNs' Interruptions Reporting

344. We also note that Ofgem are proposing to introduce a licence condition requiring minimum performance levels for the completeness (95 per cent) and accuracy (90 per cent) of GDNs' interruptions data which will take effect on and from 1 April 2009.

345. The level of interruption on the gas distribution networks continues to be very low. Indeed, in Ofgem's consumer research they cite that "unplanned interruptions to consumers' gas supplies are a relatively rare event and only a few respondents had actually experienced one". Further to this National Grid continues to provide a good level of service and supplies are typically restored the in timely fashion. As a result we do not believe that allocating further resource to measurement of interruptions is either necessary or appropriate.

346. Further to this, it is recognised by all industry participants that there is considerable inherent difficulty in recording the data associated with gas interruptions due to the manual data collection process required. This is in contrast to the DNOs which are more readily able to systematise their records collection because of the nature of their network and outages. The inherent problems associated with the manual data collected are reflected in the current version of the RIGs reporting definitions whereby the capture of the interruption start time is on a "best endeavours" basis and the duration is reported to the nearest hour.

347. We appreciate that Ofgem have set targets in their proposed licence condition which acknowledge the difficulties in collecting totally accurate data. Indeed we endeavour to provide the most accurate data to Ofgem that we can. However we are concerned that the measures proposed will not be practical in reality and we are currently unable to see how accuracy and/or completeness can be measured. We do not maintain a secondary source of interruptions data, against which to compare our submissions. Without this supporting data it is unclear how the GDNs might be able to demonstrate compliance with such a Licence Condition, with the associated risk that this may place the GDNs in breach of their Licence. As a result we do not support the introduction of the proposed Licence condition about the accuracy of the interruptions reporting because we believe this to be impractical, and as explained above, unnecessary. National Grid is willing to discuss this further in order to understand Ofgem's objective in relation to this licence condition.

Question 2: Do you support our proposals for improving the accuracy of pipeline records?

5.2 Accuracy of Pipeline Records

348. In support of our points in section 2 the number of DR4s/km of main raised by each of our networks since January 2006 is shown in the table 5.1 below:.

	DR4s Raised since Jan 06	KM of Main	DR4s / KM
EoE	7059	49346	0.14
London	3450	23373	0.15
North West	7305	34521	0.21
West Midlands	5624	24199	0.23
Total	23438	131439	0.18

Table 5.1 – Number of DR4s Raised per KM of Main by Network

349. This analysis shows that there are significant variations between the underlying rate despite consistent processes between the networks. As a result it is not appropriate to draw conclusions from this data. Further to this, as Ofgem cite, the inclusion of this metric may influence the behaviour of the GDNs in raising or suppressing DR4s and DR8s to help manage the perceived level of performance.

Question 3: Is Ofgem's proposed approach to setting allowances for the outputs and quality of service arrangements for 2008-13 appropriate?

5.3 Outputs and Quality of Service Arrangements Allowances

350. As stated in section 2 we are disappointed by the approach that Ofgem has adopted for the determination of allowances for compensation payments.

351. Ofgem's analysis takes no account for the underlying variation in the level of payments between networks. This is most starkly apparent in the London, where Ofgem have based the analysis on out of date data. This has been exacerbated by the use of the lowest level of compensation payments in the last 5 years which, is approximately 350% lower than the level incurred in 2006/7. As the age of the risers in high rise blocks flats increases the level of payments will increase. This is not reflected in Ofgem's model. Further to this the application of an arbitrary productivity assumption that the GDNs can achieve a 2.5% efficiency improvement year on year across all interruptions is unfounded. The process of reinstating supply is a manually intensive process, requiring operatives to repair the failed equipment, and then visit every one of the affected properties to purge and relight their systems. In such a manual intensive process, there are not technological or process improvements which can deliver a 10% improvement in our performance over 5 years. Ofgem should substantiate this productivity improvement or remove it from their analysis.

352. Ofgem should remove the cost pass through of 5% of the costs in excess of the cap for TPWI payments. The 5% of cost in excess of the cap does not provide an additional incentive for the GDNs to reinstate supplies quicker than they would do otherwise because there are already considerable incentives in place for the GDNs to reconnect customers as quickly as possible which outweigh the additional incentive costs (overtime payments, contractor costs, and adverse publicity as a result of the interruption etc). Instead the additional costs represent a windfall loss to the GDN, simply because of the incidence of another parties plant failing. NGG has insurance cover at £1m for all incidents greater than £250,000. Even after applying the current proposals of reducing insurance costs by 36% over the period, this would reduce the insurance premium to £640,000.

353. Finally, Ofgem should fund the efficient costs associated with the Consumer Redress Scheme, which are expected to arise as a result of the Consumer, Estate agents and redress bill from Summer 2008 onwards. We estimate the set up costs to be £50,000, with ongoing additional annual costs in the region of £200,000 for the Ombudsman Scheme. These costs are based on the number of gas related energywatch and escalated complaints received by National Grid and the current costs of the ESO scheme.

5.4 Private Networks

354. As stated in section 2 we support Ofgem's proposal to review the adoption of private networks on a case by case basis. The following text provides additional information.

355. The owner of any private network is legally obliged to ensure that it operates safely and that it is maintained to an appropriate standard. However, where the owner is either unwilling or unable to maintain the assets to the level required we agree that it may be advantageous, in the interests of public safety, for such networks to be adopted by the GDNs. In transferring these obligations to the GDNs, it is important that Ofgem accept that this will result in significant additional expenditure which will need to be borne by gas customers, and that the GDNs must be granted appropriate protection from the risks that accompany this obligation.

356. We believe that it will not be possible for GDNs to merely adopt such private pipe networks without significant works because it is unlikely that construction and maintenance records will be adequate in most cases to demonstrate that such systems are safe and have been constructed and maintained to the appropriate standard required by the GDN. This implies that, in the majority of cases, it will be necessary for the GDN to replace the pipe system at the time of adoption, incurring significant expense. The level of work required to adopt assets may also place a constraint on the numbers of systems of pipes that can be adopted, because of GDN resource constraints.

357. Further to this there are a number of practical difficulties which are likely to make the adoption of some private networks very expensive. For example, private networks may exist in secure locations such as prisons, army barracks, and other defence establishments, or within process works e.g. chemical factories. Our experience shows that working in such environments is difficult and often significantly more expensive than comparable works elsewhere. To this end it is entirely right that Ofgem have decided to allow the GDNs to log up the expenditure associated with the adoption of private networks by the GDNs with an ex post inclusion in the RAV subject to an efficiency test.

358. To limit the size of the potential cost to the existing consumers, we recommend that Ofgem consider putting a capital expenditure cap for private adoptions in place for each year of the PCR. The GDNs would be permitted to spend up to the cap, but cost in excess of the cap must be discussed with Ofgem. This will also provide the GDNs with protection should a major public body (MoD, NHS or HM Prison Service) decide to request adoption of all of their private networks within their property portfolios. We would welcome the opportunity to discuss this in more detail with Ofgem if required.

Chapter Six – Incentives

Question 1: Are the proposals for the capex rolling incentive and IQI appropriate?

359. As stated in section 2, we continue to believe that the differing nature of capital and replacement expenditure justifies a different formulation of incentives. However, it appears likely that a rolling incentive, as part of the IQI first seen at DPCR4, will be implemented at GDPCR.

360. With this in mind, there are some areas where further clarification is required:

- Updating the baseline for exogenous changes that have occurred since the submission of the October BPQ and which have been incorporated in GDNs July updates in line with Ofgem's process e.g. material changes to major LTS schemes;
- The treatment of investment associated with Exit and Interruption Reforms;
- We anticipate that any investment associated with network extensions to fuel poor communities will be dealt with outside the IQI mechanism.

Question 2: Are the proposals for the mains and services replacement incentive appropriate?

361. We believe that the supplementary incentive mechanism is an effective way of managing variations in mains replacement workloads and agree that the proposed developments outlined in the initial proposals, namely the inclusion of additional diameter bands, the inclusion of separate services matrix values and symmetrical incentives, will improve its effectiveness.

362. However, we do not support the proposal to establish GDN specific caps in place of the current company wide cap.

363. From an HSE programme perspective, Outer Met is included within London whereas for price control purposes, Outer Met is part of East of England. Consequently, in delivering the HSE target for London, variations in the relative split of work between London and Outer Met can result in material variances compared with the price control allowances for both London and East of England.

364. The application of a GDN specific cap for replacement expenditure is inconsistent with the IQI which has been correctly designed to operate on a company basis to ensure there are no perverse incentives to manipulate costs and workloads between networks.

365. Finally, we believe that it is appropriate that the DNMRA component of the allowed revenue formula should be retained to correct for replacement workload variances rather than making such adjustments through the RAV. We believe that the impact of DNMRA on the variability in transportation charges is best addressed by other means, for example by moving the timing of transportation charge changes to April rather than October so that variations in allowed revenue from year to year are not magnified by mid-year changes to charges. The retention of the DNMRA more closely aligns variations in the company's spend with the income and helps to offset some of the financeability issues associated with undertaking additional replacement work.

Chapter Seven – Sustainable Development

No additional information.

Chapter Eight – Other Issues

8.1 Xoserve Questions

366. The following includes additional information in support of our response to question 1 in section 2 and also provides the remaining responses to the other xoserve related questions from chapter eight.

Question 1: Do you agree with our proposed approach to the funding of xoserve?

367. We have stated in section 2 that we support the objectives of Ofgem's proposed core and user pays approach because it is important that the party which is responsible for incremental expenditure bears the additional cost. The following details how we believe a user pays approach may work in more detail.

368. We are concerned about the way in which Ofgem may treat xoserve capex. Within the guidance notes for the updated BPQ, Ofgem have stated that all expenditure associated with xoserve should be treated as opex. We do not believe that this approach is appropriate. Due to the lumpy nature of the capital spend, especially in the area of IS upgrades, capital expenditure may lead to unnecessary charge variations for gas consumers. Ofgem should treat this expenditure in the same way as other non-operational capex and keep it as capex.

369. Should a fundamental change to the current regime require additional investment in UK Link, Ofgem should allow the GDNs to fully recover this investment through their RAVs.

370. To facilitate the introduction of a user pays approach, the modification and system changes governance framework will need to be amended. The changes will include;

- A consistent and transparent approach needs to be devised to distinguish between core services and user pays services. Core services will continue to be funded through the traditional price control allowance approach.
- It will require changes to UNC, to remove obligations on the GDNs to fund all system changes resulting from implemented UNC modifications and a change in the emphasis on the way in which the relevant objectives are considered when reviewing modifications, as well as licence drafting changes.
- A mechanism to enable the setting and collection of charges.
- As the key party with decision making responsibilities, the Authority will be required to make decisions on the allocation of costs on a mod by mod or change by change basis throughout the control period.

371. Below we have set out how we consider user pays may be applied to a number of different categories of service.

8.1.1 Core services

372. These activities are described in the UNC and billed out to shippers under the umbrella of transportation charges. Since these are regulated activities, xoserve could not offer these services "on their terms". Xoserve is not licensed and has no contractual arrangements for the provision of regulated services. Instead, xoserve is a central provider of these services on behalf of the transporters. Hence all code services would remain as provided by transporters. To facilitate users pays, the income could be passed through xoserve, provided the ASA funding arrangements were suitably modified. Consideration would need to be given as to how the charges should be established and published.

373. As part of previous discussions, xoserve has reviewed their current service provision and identified 5 possible service lines (shown in Table 8.1 below) which could be charged on a user pays. The services lines were assessed against the following criteria:

- Users do not directly fund xoserve
- Users have discretion over use of service
- Cost is dependent upon the usage (i.e. significant variable element)
- Would adoption of a user pays be cost effective

Service	Cost (£m)	Users do not directly fund xoserve?	Discretion over use of service?	Cost Dependent upon usage?	Comments
Query Management	£2.3m	Yes	Yes (to a limited extent)	Yes	It could be construed as perverse to charge for query management due to service level considerations
Admission of new shippers/suppliers	£0.04m	Yes	Yes	Yes	Cost incurred is immaterial and could be portrayed as a barrier to entry into gas market
Must Reads	£0.6m	Yes	Yes	Yes	Must reads are already charged on a per unit basis as a transportation charge – no change required
Services under licence (e.g. meter point queries)	£1.1m	Yes	Yes	Yes	We believe that this service line may be a suitable candidate for user pays
User reports	£0.2m	Yes	Yes	Yes	Charging already in place for ad-hoc reports etc.

Table 8.1 – Xoserve Service Lines Vs User Pays Matrix

As a result, we believe that the only existing service which could be considered as part of a user pays approach is Services under licence.

8.1.2 How it could work for future changes

374. We believe that there is a much wider scope for future UNC modifications and additional services to be considered under a user pays approach once the process has become proven.

375. The key to establishing a user pays regime is to establish what, in terms of incremental change, has been funded through transporters' PCR allowances and what changes have not. Where it is decided that the funding has not been included, robust governance arrangements are required to ensure the costs can be diverted to the appropriate class or group of users. This would need to be done on a consistent and transparent basis. Apportioning and splitting costs would be the role of the Authority, with decision making required on a mod by mod, change by change basis throughout the control period.

376. For several NTS process, e.g. exit capacity, GDNs would be classed as "the User". From a DN perspective we would need to ensure that in the event we became liable to fund NTS changes that we would be able to pass these charges through to shippers.

Question 2: How should we address any benefits arising to xoserve from redundancy created from the replacement of UK link?

377. As a result of the reasons that Ofgem cite within the Initial proposals the benefit of any redundancy generated from the replacement of UK Link should be treated on an ex post basis. Any ex ante approach will require an ex post assessment to determine the true level of benefit accrued by xoserve over the period. Due to the small scale of this potential benefit, a prospective assessment is not required. It is important to note that there is a corresponding downside risk associated with UK link replacement, that may result in an overspend being borne by the transporters during the price control review period under and ex post adjustment.

Question 3: Do you agree with our approach of modifying SSC A15 to facilitate governance arrangements for user-pays?

378. We cannot see any specific need to modify Standard Special Condition A15 to implement user pays. However, changes to the other licence conditions may be required. If Services under Licence is to become a chargeable service it may be necessary to amend Standard Special Condition A31 and if the UNC and system modification classification system rules are amended, Standard Special Condition A11 and Section U of the UNC may need to be modified.

Question 4: 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?

379. The GDNs take their responsibilities to fund xoserve seriously. The provision of the services that xoserve provide are mandated by the UNC, ASAs and the Licence. This provides a robust framework to ensure that the GDNs meet their obligations. On a more pragmatic basis, it is unlikely that the GDNs would wish to under fund xoserve, because any saving that they may realise would be dwarfed by the scale of the transportation charges which might be put at risk.

380. To show how the governance framework ensures that the transporters fund xoserve in practice we have set out two theoretical cases of under funding. One is where the transporters act as a group and one is where a single GDN acts alone.

8.1.3 Acting as a group

381. UNC Section V gives notice to the shipper that GDNs will use an agent to perform certain activities. This section of the UNC establishes that xoserve operates as the transporters' agent. As such, the transporter is still the contract principal: there are no direct regulated UNC contractual obligations that rest with xoserve. All UNC obligations rest on the transporter and it is the transporter that would be liable in the event that those services failed to meet standard or were unavailable because of funding shortfalls. Therefore, if the transporters were to collectively under fund xoserve, this would lead to a failure to deliver the GDNs' obligations under the UNC and GDNs would be in breach of the UNC and potentially their licence, (xoserve provide information services under licence condition Standard Special Condition A31).

8.1.4 Acting individually

382. Standard Special Condition A15 requires all transporters (inc. NTS) to use a common subcontractor and enter a joint (multilateral) service agreement (the ASA). This requires and provides for a communal approach for xoserve to provide these services. The ASA details the services that xoserve offers, the vast majority of which are regulated.

383. Were a single transporter to under-fund xoserve, this would breach the pre-agreed sharing mechanism in the ASA. Furthermore, any shortfall could result in all transporters failing to meet their obligations under the code (to shippers), under licence (to Ofgem) and under the ASA (to their fellow transporters). This would leave the offending GDN exposed under the ASA contract, their licence and, potentially the UNC as well. Therefore, no change is required.

8.1.5 User Pays

384. We do not foresee that the introduction of user pays will increase the risk of xoserve being under funded by the transporters. Whilst “user Pays” may result in xoserve losing relatively small volumes of income if the expected level of demand does not materialise, it will not affect the obligations on the GDNs to deliver UNC services and co-operate on how they are paid for, as described above.

Chapter Nine – Financial Issues

Question 1: What are your views on the factors relevant to our consideration of cost of capital?

9.1 Overview

385. National Grid believe that, at a conceptual level, the key factors relevant to Ofgem's consideration of the cost of capital are:

- market evidence on the building bocks of the CAPM model and the relationship between each of those elements
- market evidence on aggregate cost of debt and aggregate cost of equity
- previous regulatory determinations on cost of capital taking into consideration differences in the risk profiles of the regulated companies
- any asymmetric risks associated with the regulatory package which require an adjustment to the allowed rate of return
- other bottom up models for estimating cost of capital such as Fama-French and other top-down models for assessing cost of capital such as the dividend growth model and market to asset ratios
- empirical and / or theoretical academic assessments of the robustness of various cost of capital models

This response sets out our initial views on some of these items. We acknowledge Ofgem's indication that the numbers set out in the Initial Proposals only represent "modelling assumptions" and we would expect to submit further views and evidence on cost of capital as the debate develops through the GDPCR.

9.2 CAPM Building Blocks

386. The components of a vanilla WACC under the CAPM model are:

- cost of debt (consisting of the risk free rate plus the debt premium)
- cost of equity (consisting of the risk free rate plus the equity risk premium multiplied by the appropriate equity beta)
- gearing level

387. It is important to note that the above components are all interrelated and if one changes then it is crucial that the impact on the other elements is considered. This is highlighted with particular reference to the mooted change in gearing below.

9.3 Cost of Debt

388. We note that for the "modelling assumption" in Initial Proposals, Ofgem has used an aggregate cost of debt figure 20bps below that used in the TPCR. This suggestion appears to take no account of the recent decisive turn in interest rates and as far as we can see the only significant change since TPCR in terms of cost of capital is that the historically low interest rates that have persisted for several years are now on the increase.

389. This presents a problem at this review. In setting the cost of debt for a price control, regulators are seeking to determine a reasonable proxy for the rates that will apply for the next five years. We have very much supported the use of long term trailing averages in previous reviews on the prudent basis that the risk free rate is expected to revert at some time towards a higher longer run average.

390. However, the recent rise in interest rates has seen spot rates rising above the trailing average. Persisting with the use of trailing averages in such an environment is no longer appropriate. Given the generally accepted view that future interest rates are likely to be higher rather than lower, such an approach is likely result in insufficient allowance for debt funding. Therefore, National Grid would argue that the base figure from which to build the debt allowance is the current spot rate. On top of that, we would argue for an additional allowance to cover volatility around the spot rate as well as further Bank of England interest rate increases.

391. We appreciate that Ofgem may be concerned that moving from a long run trailing average to a "spot rate plus" is asymmetrically tilted against consumers over the interest rate cycle. However consumers can be expected to benefit from this approach: it is more likely to provide networks with positive incentives to invest over the interest rate cycle and it reflects the reality that companies bear the interest rate risk between price controls. Ofgem raise the possibility of indexing (perhaps with trigger points) as an alternative to this approach and we deal with that below.

392. In analysing current evidence on cost of debt in more detail, we have disaggregated the cost of debt into its component parts of risk free rate and debt premium.

9.3.1 Risk Free Rate

393. Market evidence on yield movements for both conventional and index-linked gilts, which may be used to derive movements in the risk free rate, shows almost constant yield growth since the beginning of December 2006. Figure 9.1 shows Bloomberg quotes 10yr IL debt yields at

less than 1.4% at 1/12/06 and around 2.3% in early July representing an increase of over 80bps.

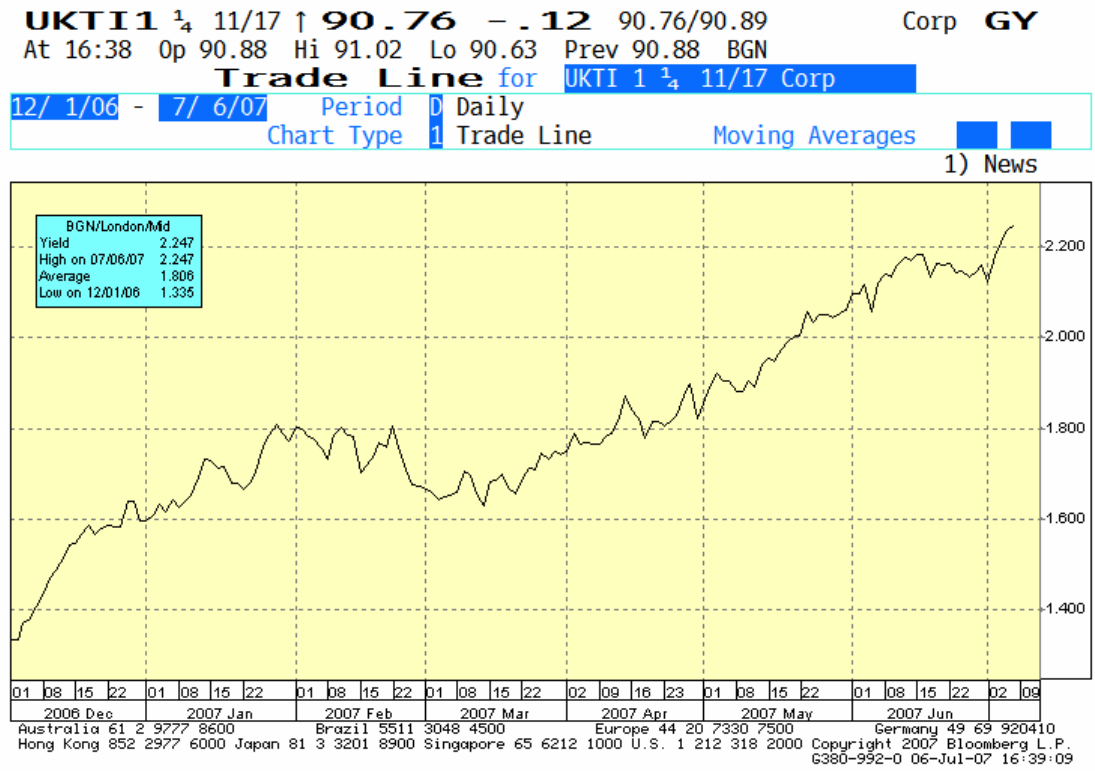


Figure 9.1 - UK 10 Year Index Linked Gilts – Movement Since TPCR

394. However, using index linked gilts as a proxy for risk free rate is problematic since it is widely accepted that the yields on index linked gilts have been distorted (downwards) over recent years by the current level of investor demand for index linked investments.

395. National Grid's preferred approach to assessing the risk free rate is to use an approach similar to that set out by Smithers in their report for Ofgem during the TPCR. That is, that a better market-based estimate of the risk free rate is provided by the nominal yield on medium-dated bonds, less the Bank of England's inflation target. Smithers used a 2% adjustment.

396. Figure 9.2 below demonstrates that the current nominal yield on 10 year conventional gilts is in excess of 5.5% which gives an estimate of just over 3.5% for the spot risk free rate using the Smithers adjustment.

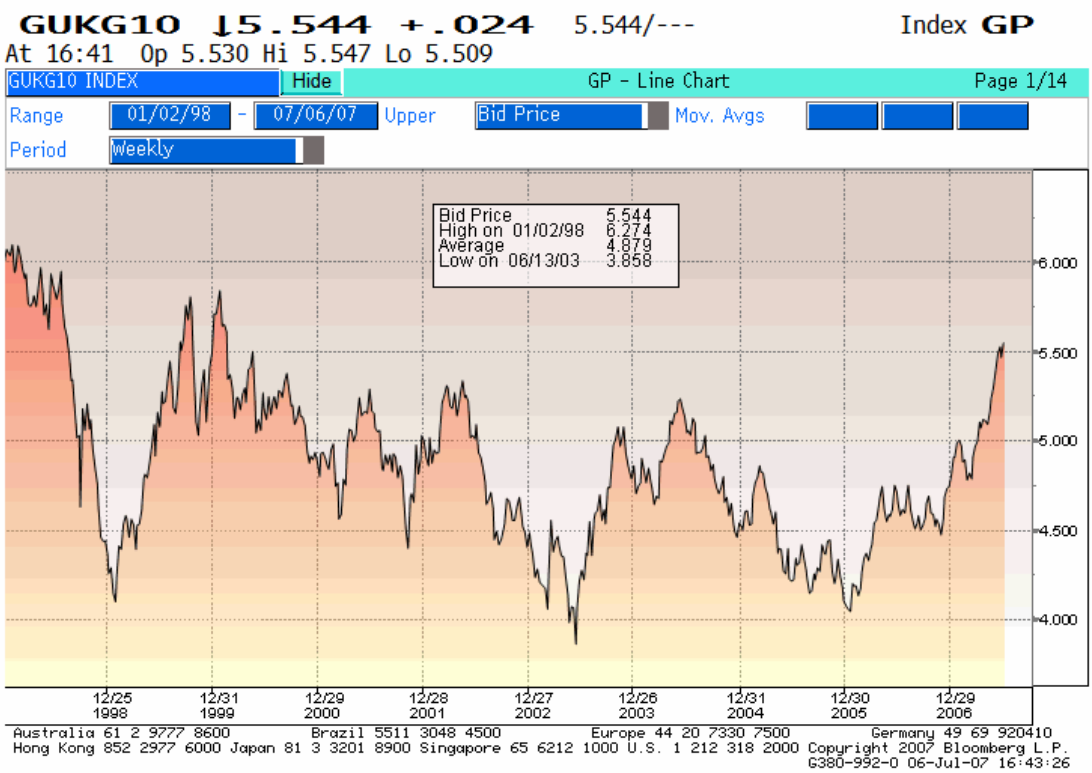


Figure 9.2 - UK 10 year Conventional Gilts – 10 Year Average

397. However, the Smithers approach may understate the required adjustment. Their adjustment for the Bank of England inflation target is based on the 2% CPI inflation target. However, gilts are indexed to RPI which since 1989 has, on average, been around 80bps higher than CPI. This difference is demonstrated by the analysis summarised in Table 9.1 below:

Statistics for period June 1990June 2007	CPI	RPI	(RPI-CPI)
Arithmetic average	2.71	3.53	0.82
Geometric average	2.69	3.51	0.82
Max	8.50	10.90	3.10
Min	0.50	0.70	-3.10
Median	2.00	3.00	0.90
Variance	3.92	4.63	1.69
Confidence interval (90%)	-0.55, 5.97	-0.01, 7.07	-1.32, 2.96

Note: Based on monthly data.
Source: ONS, Oxera calculations.

Table 9.1 – RPI and CPI Descriptive Statistics

398. Therefore, it would be more justifiable to reduce the nominal yield on conventional gilts by 2.8% to estimate the risk free rate. This would give a current spot risk free rate of around 2.7%.

399. Against this base, the risks appear to be on the upside. In addition to the recent rate increases, market predictions for six month LIBOR rates are that they will increase slightly from today's rate (to factor in another Bank of England base rate rise) and that they will then remain fairly flat at that level for the next five years.

400. Therefore, as stated above and given all the recent market evidence, National Grid believes that the lowest possible estimate for current risk free rate is 2.7%. For the purposes of setting an allowance for the next price review period, additional protection to cover the volatility of interest rates around the current rate and against future rate increases would also have to be factored in.

9.3.2 Debt Premium

401. Corporate credit spreads have increased since TPCR and are expected to continue increasing over the next few years.

402. Swap spreads form a component of the spread over the risk free rate that is used to approximate the debt premium. Typically there is a correlation between swap spreads and corporate spreads over gilts and therefore an increase in swap spreads can be used to infer an increase in the corporate debt premium. Figure 9.3 demonstrates an 8bps increase in swap spreads since the time of the TPCR:

Figure 9.3 – Movement in Swap Spreads Since TPCR

403. The most recent Bank of England "Financial Stability Report" (Figure 9.4) from April 2007 highlights the expected increase of corporate credit spreads:

> "The high availability of credit is supporting corporate performance. Benign macroeconomic conditions, strong profit growth and high cash balances in recent years have contributed to historically very low global corporate default rates…..

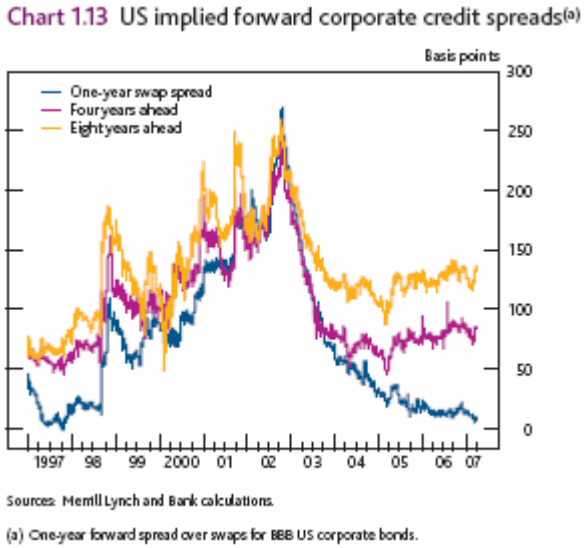


Figure 9.4 – US Implied Forward Credit Spreads

> …..But this unusually low level of corporate defaults is not expected to continue indefinitely. The chart (above) shows the one-year cost of borrowing currently and that implied in four and eight years' time. This suggests that markets expect corporate default rates to remain low in the near term, before rising back towards historical levels over the next few years."

404. All of this data provides further credence to the argument that the overall cost of debt has increased since TPCR and is indeed expected to continue increasing over the next few years.

405. Finally, National Grid would argue strongly that to estimate a debt premium for gas distribution using the TPCR allowance as a base, the figure must be adjusted to take into account the fact that the credit rating for a gas distribution business is typically lower than that of a transmission business (at the same gearing level). Such an adjustment may be expected to add around 15 to 20 basis points to the debt premium for each notch down the credit rating scales.

406. Therefore, given the level of increases that have been seen and that are expected on corporate spreads, National Grid feels very strongly that it would be inappropriate to reduce the debt premium allowance. Despite this, we would also not expect to see a significant increase in the debt premium. However, although we believe that the lower bound of the range for debt premium should be based on the figure used in TPCR, we are strongly of the

opinion that this figure needs to be adjusted for the difference in typical credit rating between gas distribution and transmission businesses. Thus, the lower bound should be the 1.25% used in TPCR plus 15bps to adjust for the minimum credit rating differential to give a figure of 1.40%.

9.3.3 Cost of Debt - Conclusion

407. Our provisional survey of the market evidence on the components parts of cost of debt indicates that the bottom end of the range for cost of debt is 4.1% (pre tax real). This incorporates a risk free rate, low end estimate of 2.7% based on the current nominal yield on 10yr conventional gilts less the Bank of England inflation expectation and a debt premium estimate of 1.4% which is based on the figure used in TPCR plus an adjustment to reflect the typically lower credit rating of gas distribution businesses compared with transmission. National Grid would expect that Ofgem's allowance for cost of debt to be in excess of 4.1% in order to compensate for interest rate volatility and the possibility of further interest rate rises over the next period.

9.4 Indexation of Allowances

408. We acknowledged above an apparent asymmetric bias that may arise when fixing costs of debt for 5 years. Ofgem have raised the possibility of introducing some form of indexing mechanism (perhaps with triggers) to address this issue.

409. In making such a change, Ofgem would be balancing the small premium customers pay to fix their debt rates against the potential volatility of prices arising from a pass through of interest rate changes. Introducing a trigger level before prices change would dampen the volatility in exchange, presumably, for a smaller risk premium for companies. This is clearly an important and legitimate area for discussion.

410. However, in the time frame available under the GDPCR, Ofgem is unlikely to be able to resolve all the issues associated with debt indexation. Some of the key implementation issues that would need to be addressed are:

- What elements of the cost of capital allowance should be indexed and which combination of indices / bonds should be used for the benchmark? One important aspect that will need to be determined is the desired speed of response of the index / benchmark to interest rate changes i.e. whether to use 2 year, 5 year, 10 year or longer bonds. This question would appear to take regulators to the heart of companies' financing decisions.

- Would there be any unintended consequences of indexation e.g. triggering a move towards even higher gearing levels?
- Would the financial model need to be re-run every year to assess financeability issues that arise as a result of indexation of allowance adjustments to prices?
- Should triggers be used to activate the indexation? At what levels should they be set and should they be symmetric?

National Grid feel very strongly that all of these issues (at least) would need to be addressed and resolved through the normal consultative process before any form of indexation could be introduced.

9.5 Gearing:

411. We accept that it is the case that companies are achieving higher gearing than previously assumed in price reviews while maintaining investment grade credit ratings. This is part of a long term shift in credit markets which has gone alongside a downward drift in interest rates and the creation of deeper debt markets.

As noted above, the interest rate cycle seems to have turned and credit markets also seem to have become more difficult. An assumption that past benign conditions continue into the future may prove too optimistic. National Grid consider that it would be inappropriate at this time to adjust the gearing assumption from that used in TPCR given that the only obvious change since December has been of more difficult credit conditions going forward.

412. From our discussions with rating agencies, we believe that National Grid Gas would be unable to retain its A rating at a gearing level of above 60%-62%. National Grid Gas has various commitments to existing bondholders as well as to institutions such as the European Investment Bank who currently provide some of our funding to maintain its A grade credit rating. Therefore, Ofgem's proposals of a possible range up to 70% are inappropriate from a National Grid perspective and would be potentially very costly to achieve.

413. Finally, from a practical perspective, National Grid will need guidance on how the proposed tax claw-back would operate in National Grid's case where transmission and distribution operate within a single ring fenced entity. That is, if allowed gearing (for tax purposes) is set at 60% for transmission and 62.5% for distribution how would Ofgem determine what the actual gearing level is for each of distribution and transmission in order to calculate the amount of tax to be clawed back under each price control.

9.6 Cost of Equity:

414. We note that Ofgem has continued with the assumptions used in TPCR for modelling the cost of equity. Recent stock market volatility may have increased the measure of 'implied volatility' as derived from traded options on FTSE100 shares. This argues for a higher cost of equity.

415. National Grid feel that the range for cost of equity used in TPCR is an appropriate starting point for the GDPCR. Clearly however, it is important that in determining its Gas Distribution allowance for cost of equity, Ofgem adjusts the above range and point estimate for the following:

- The outputs from the planned relative risk analysis between Transmission and Distribution; and
- The adjustment required to cost of equity as a result of any gearing assumption above that used in TPCR (i.e. 60%).

416. National Grid, in conjunction with the other GDNs has commissioned Oxera to perform and present a relative risk analysis between Transmission and Distribution. Oxera will submit this evidence to Ofgem in due course.

417. In terms of an adjustment to cost of equity as a result of gearing changes, National Grid believes that there are strong theoretical reasons to suggest that the cost of equity should rise with leverage.

9.7 Overall Allowed Rate of Return – Asymmetry of Cash Flows

418. As reflected elsewhere in this submission, we believe that the cost allowances proposed by Ofgem in Initial Proposals are likely to be unachievable. In principle, if the risks inherent in the price control settlement are asymmetric, this could be compensated by an adjustment to the overall rate of return. In deciding on the final rate of return, Ofgem will need to consider where the balance of risk lies in the overall regulatory package.

419. One particular area of asymmetry is the risk that companies will be unable to recover their full regulatory asset value over many regulatory cycles. This risk operates only one way – against the company – and is exacerbated by long regulatory depreciation periods. This is a clear area of comparative difference between network types. Gas distribution has a much longer regulatory depreciation period than, for example, electricity transmission. This difference leaves gas distribution shareholders exposed to the terminal value risk for many more regulatory cycles.

420. Given that gas is a depleting resource and that gas in homes has been identified as a major source of carbon emissions by the government, it would seem that this terminal value risk is also more likely to be felt in gas distribution than in other networks.

421. This long term uncertainty over investments in gas distribution assets could, conceptually, be addressed through additional return or a review of asset lives.

9.8 CAA review of airports

422. We believe that it is appropriate that Ofgem takes into consideration other regulatory determinations and academic studies on cost of capital in setting its allowance for the GDPCR. However, in doing this, it is crucial that Ofgem recognise the fundamental differences between gas distribution and other regulated businesses on which the studies / determinations have been made. In the same way that Ofgem are proposing a detailed relative risk analysis between Transmission and Gas Distribution, it is just as important to carry out equivalent reviews between Distribution and other industries if regulatory determinations in those other industries are to be used as a comparison. This is particularly relevant in the case of the CC review of CAA's proposals for cost of capital for BAA.

Question 2: 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?

9.9 Factors Affecting Financeability

423. As a general principle, National Grid believes that it is hard to argue for an NPV positive adjustment for financeability issues caused by company underperformance. However, where possible, we believe that it is beneficial to both shareholders, bond holders and customers to make NPV neutral adjustments to address financeability issues where ever possible and regardless of their cause.

424. We believe that in general it is not possible to isolate one particular factor which may have contributed to cash or earnings reductions and determine with any certainty the extent to which it has caused financeability issues.

425. Therefore, without having seen the detail of the financials National Grid find it difficult to conclude on whether the issues set out in paragraph 9.36 have indeed caused the financeability problems. Therefore, in the absence of such certainty, we cannot determine whether it should be the sole responsibility of the company to remedy the financeability issues.

426. In terms of what types of financeability adjustment mechanisms may be used by Ofgem; National Grid believe that the following should be considered, and where used, should be applied consistently across all networks:

- Adjustment to Asset Life Assumptions: As set out in the fourth consultation document (paragraph 6.13/4), we agree that it would be appropriate to review the treatment of repex, non-operational capex and capex as part of the financeability review. A financeability adjustment made on this basis would have the advantages of being NPV neutral, as well as providing the opportunity to reflect more accurately asset life predictions for all asset classes (as discussed above).

- Assumption of a Proportion of Index-linked Financing: It should be noted that this assumption would only have an impact on the cash flow based financial ratios – such as PMICR. For P&L based ratios (such as FFO / debt), because the indexation cost of the finance has to be accrued in the P&L, this does not improve the ratio in comparison with conventional debt.

  Additionally, as stated in our response to the fourth consultation, we believe that it would be necessary to allow for the additional costs associated with the issue of index–linked finance and the proportion assumed should not exceed 25%. However this point is subject to the availability of index-linked finance. It would be important that Ofgem understand the depth and dynamics of this market before making assumptions on the proportion of index-linked debt for the notional GDN.

- Gearing Assumption: By reducing the notional gearing level, Ofgem would reduce the relative level of debt interest payments as a proportion of overall cash flow. This added flexibility could reduce or remove financeability issues.

- Equity Issuance: We believe that equity issuance is an appropriate method of making financeability adjustments providing that the total cost of issuance is allowed for. That is both the direct and indirect costs of equity issuance. The September 2006 Smithers report conducted for Ofgem in support of the TPCR concluded that even for a regulated utility, indirect costs of equity issuance (i.e. the impact on overall share price of an equity issuance required by the regulator) can be seen to exist. Therefore, it would be inappropriate for Ofgem to ignore such costs in making their financeability adjustment.

427. Regarding the financial ratios in Ofgem's model for National Grid, we believe that the levels for the PMICR ratio (at around 1.3) are low and certainly fall below the "comfortably

investment grade" criteria. Therefore, we are of the opinion that some form of financeability adjustment would be required to address this.

428. Furthermore, National Grid believe that the opex allowances proposed by Ofgem in Initial Proposals are unachievable. Not only does this create issues around the future expected profitability of the business but this also heightens problems with already stretched financial ratios.

This raises concerns around Ofgem's commitment to provide sufficient allowance to maintain comfortable investment grade levels. Furthermore National Grid Gas has various commitments to existing bondholders to maintain its A grade credit rating that will be difficult to uphold.

429. National Grid feel very strongly that the current regulatory package, as proposed in Initial Proposals is untenable without either:

- Significant movement on cost allowances to reflect a more realistic outcome. National Grid fully support the setting of challenging targets which the GDNs are incentivised to achieve, however this needs to be done from a realistic base; or
- A substantial financeability adjustment to ensure that both customers and shareholders do not suffer unduly from the effects of credit down grades.

National Grid's strong preference would be for the former as this would address the root cause of the issue rather than the "sticking plaster approach" of a financeability adjustment.