Gas Distribution Price Control Review Fourth Consultation Document

A Response by National Grid Gas Distribution

April 2007

1. We welcome Ofgem's commitment to providing for a full and open dialogue on the GDN cost assessments and the process for determining overall allowances at this stage of GDPCR. We are happy for our response to be placed on the Ofgem website.

Section 1: Executive Summary

2. The setting of overall allowances and the use of incentives underpins the entire price control process, therefore warranting the substantive discussion contained within the fourth consultation document. Our key points can be summarised as follows.

Comparative techniques

3. We fully endorse the use of comparative techniques to drive value for the consumer as part of the Gas Distribution Price Control Review process. However, the limitations of the opex analysis, particularly data consistency, organisational differences and the level of fit, mean that the most robust method of identifying efficiency opportunities is likely to be via a 'top down' approach. As such, Ofgem should avoid the risk of applying inappropriate cuts identified by a bottom up approach before such an approach can underpinned by a cost reporting framework.

Glidepaths

4. Both the level and the assumed speed of gap closure for any identified efficiency saving must be reflective of the confidence that such a gap exists and the GDN's ability to reach the desired target in a specified timescale. Not all efficiency savings identified represent true inefficiency, with any one particular cost driver failing to explain all the variances and an element attributable to the underlying characteristics of the network concerned. We therefore advocate an approach premised on an upper quartile target with significant, but not 100%, gap closure over the whole review period.

New costs

5. The analysis presented in the consultation document focuses on existing costs, setting an efficiency target which overstates the productivity assumptions and the privatisation effect. Over the period of the price control, substantial additional costs are anticipated which should

also be built into cost allowances. Examples of such costs include cyclical maintenance projects, tightening waste regulations and the impact of growing competition in meterwork.

Investment strategy

6. It seems evident from a comparison of cost submissions that different GDNs are adopting different investment strategies. In the interests of protecting customers, these different strategies must be understood – as they lead to some divergence between different networks investment and operating expenditure profiles – and tested to ensure that they are efficient. For example, National Grid's investment submission is substantially lower – on a cost per customer basis – than other networks, and this may be a driver for its higher maintenance costs.

Repex prioritisation

7. We believe that the presentation of our approach to mains replacement set out in the consultation document is incorrect. We are not materially increasing the volume of pipes to be replaced each year nor have we chosen to accelerate the replacement of large diameter mains beyond the level agreed early in the programme with the HSE and Ofgem. We are adjusting our approach to constructing our mains replacement to deliver very significant productivity and network improvements for consumers compared to the continuation of the previous approach to pipe selection.

Power of incentives

8. With the vast majority of our capex spend being non discretionary in nature to meet customer and statutory requirements, we believe the implementation of a stronger capex incentive than currently exists is inappropriate. The degree of forecasting uncertainty and the implementation of new policy initiatives means that an ex ante approach is difficult and may lead to inclusion of an additional risk margin within plans. As a result, we believe Ofgem should err towards a low powered incentive on capex , whilst considering a possible 'cap and collar' protection mechanism capturing the significant uncertainty around contractor prices. We disagree that repex spend should be subject to the same incentive as capex since workload volatility is managed via the supplementary mechanism.

Time line going forward

9. The consultation document raises many issues that must be resolved in order to set fair and reflective allowances. Whilst Ofgem should endeavour to correct for factual inaccuracies ahead of the Initial Proposals in May, we acknowledge that the majority of the more detailed issues will be resolved over the summer months ahead of the September update.

Section 2: National Grid's detailed response to specific questions raised

Chapter Two: Accounting Policy and Adjustments

Question 1: Do you agree with our proposed accounting adjustments? Are there any other accounting adjustments we should be considering?

10. By implementing the accounting adjustments identified in the document, Ofgem are rightly seeking to establish a consistent approach to the treatment of atypicals, related party margins and cost capitalisation across GDNs.

11. We are pleased to note that Ofgem proposes to allow an efficient level of compensation for items such as standards of service on the basis that the incremental costs of achieving 100% compliance may not always be in the best interests of customers.

12. However, we do not agree with the proposed adjustments to account for accrual releases. The releases in the base year were atypical in size and it is not realistic to suggest the same magnitude or number will be present in all years.

13. In relation to the re-allocation of logistics costs from repex to opex, we do not believe that the movement as proposed will help achieve a consistent data set across networks. Only those costs entirely incremental to the replacement activity are charged to repex within National Grid and, as such, they should remain as a repex item to ensure comparability with networks where logistics services are provided by a 3rd party and hence charged directly to replacement.

Question 2: Are there any other accounting adjustments we should be considering?

14. We appreciate that fully capturing the underlying differences between GDNs is difficult. Whilst a number of structural differences have already been accounted for, we believe that further work in relation to operating strategies and organisational structures in some areas is required.

Question 3: Do you agree with our adjustments for related party margins?

15. The principle that companies should not be additionally remunerated for an activity purely because they choose to resource it from within a wider group structure is appropriate. However, we believe that the choice of supplier should not dominate the decision of whether profit margins are allowed or not. Using a supplier from within the group, for example Fulcrum for connections works, may often be the most economic choice for consumers. Therefore, we believe that it would be more equitable to apply a market tested price for goods

and services to define the efficient cost and allowance, irrespective of whether sourced from an internal or external supplier.

16. We note and support Ofgem's proposal to apply the treatment of xoserve margins consistently across GDNs. To do otherwise would result in differential pricing of common xoserve services which we do not believe appropriate.

Question 4: Do you think we should change our treatment of non-operational capex?

17. In our response to the third consultation we stated that non-operational capex should continue to be treated as capex and not be fully expensed. This was premised upon:

- *RAV true-up issues:* in view of the discretionary nature and increased substitutability of many non-operational capex items, and the general opaqueness of typical opex settlements, changing funding to opex is likely to result in difficulties at subsequent price control reviews regarding whether funding for a particular output has or has not already been provided in a previous opex allowance.
- *Price stability*: as a material proportion of the GDNs total investment, changing treatment to fully expensed will result in a substantial step increase in prices for customers.

18. For these reasons, we continue to believe that funding should remain as capex. Whilst this would not be aligned with the TPCR treatment, the difference in scale (non-operational spend is around 35% of National Grid's total GDN net capex, compared to only 2% in transmission) justifies a difference, with reference to the three points above.

19. With respect to any incentive for National Grid to reallocate common costs, such as universal back office systems, to gain from the different treatments between businesses, we do not think this would be a reality, given the strength of internal controls, regulatory transparency on allocation methodologies and, not least, the introduction of the new regulatory reporting regime.

Quasi-capex

20. Should Ofgem proceed with a change, on the principle that funding should match the life of the product, then for consistency, the counter directional issue of quasi capex will need considering. For example, a number of high cost maintenance activities currently funded as opex are irregular in their timing, typically arising only once in a 10 to 20 year period. These activities directly maintain or improve the operating capacity of the network and will extend the useful life of the asset concerned.

Chapter Three: Operating Expenditure Analysis

Question 1: How should we bring together the various consultants' analysis to establish an efficient cost benchmark and cost allowances ? In the light of our approach to setting a benchmark, what approach should we take to glidepaths ?

21. We support the use of comparative techniques as part of the assessment of efficient forward looking allowances. However, caution needs to be exercised in applying and combining the consultants proposals. The ability to derive robust results will be impacted by:

- The limited data set of eight points, which increases the distorting effect of outliers and the level of fit arising from the chosen cost driver. A statistically sound data set for this kind of application is generally considered to include at least thirty data points;
- The need to ensure truly comparative data sets and understand inherent differences between networks driven by a range of exogenous factors, and
- The relative immaturity and variety of organisational models in play.

22. Given the limited data set and experience of it since network sales, the risk of applying inappropriate adjustments because of erroneous comparisons is considerable and could ultimately affect a GDN's ability to finance its activities. We do acknowledge however that these issues are likely to be mitigated by the following review.

Ensuring comparative data sets

23. Prior to establishing proposals, it is imperative that Ofgem are confident that any bottom up analysis has been performed consistently on a like for like data set. More specifically, Ofgem should consider the following points before applying any of the analyses contained in the consultants' reports;

- **Operating model differences** are evident across GDNs and may result in different process boundaries and cost allocation. A devolved operating model, for example, is likely to lead to responsibility for some support activities remaining within line management in the field and may explain why National Grid appears more efficient on direct opex than Scotia, but vice versa for indirect costs.

- **Differing investment strategies** must be accounted for. National Grid's decision to maintain storage capacity by repair and remediation of existing assets rather than building new assets, for example, will result in lower capex but higher opex.

- **The inclusion of new costs** such as new waste regulations and cyclical major maintenance appear to have been largely ignored in the analysis presented to date. These factors must be properly taken into account within the Initial Proposals.

- The costs or benefits of **exogenous and regional** factors should be included in allowances, where material and clearly evidenced.

- Work has been undertaken to try and ensure **consistency of activity definitions**, but it is clear consistency issues are still present.

- Care should be taken not to be **selective in the use of external or internal benchmarks**, i.e. using an external benchmark when GDNs appear uncompetitive and internal when competitive, is inappropriate given that the desktop nature of any external benchmark exercise may lead to gaps, in part, being definitional rather than efficiency related.

- **The use of consistent cost drivers** is not evident across the consultants. Ofgem and Europe Economics, for example, use customer numbers as a key driver for direct and total costs in their analyses, which is not true of PB Power. This will make a material difference to overall results.

- The use of a ‘base year’ approach from which to apply efficiencies could fail to take **account of future year cost profiles and planned savings** already captured in GDN plans, resulting in double count of cost savings.

- **Conclusions from the TPCR** process should be reflected in the analysis. It is worrying that many determinations completed in September are now, only 6 months later, largely being ignored, for example real National Grid’s earnings growth assumptions.

Approach to consolidating the consultants’ work

24. Any consolidation of the consultants’ analyses must ensure that the degree of efficiency savings identified are plausible and fair. Of the three approaches identified by Ofgem, we believe that the potential for cherry picking resulting in a target organisation which it is impossible to mirror, as well as the issues identified in paragraph 23, mean that both option one (mechanistic approach) and option two (bottom up benchmarking) are unworkable at present.

25. We support Ofgem’s third approach of ‘judgement based on evidence’, and believe this would be best applied as follows;

i. Set an efficiency target and a corresponding allowance on a per GDN basis using a top down approach which;

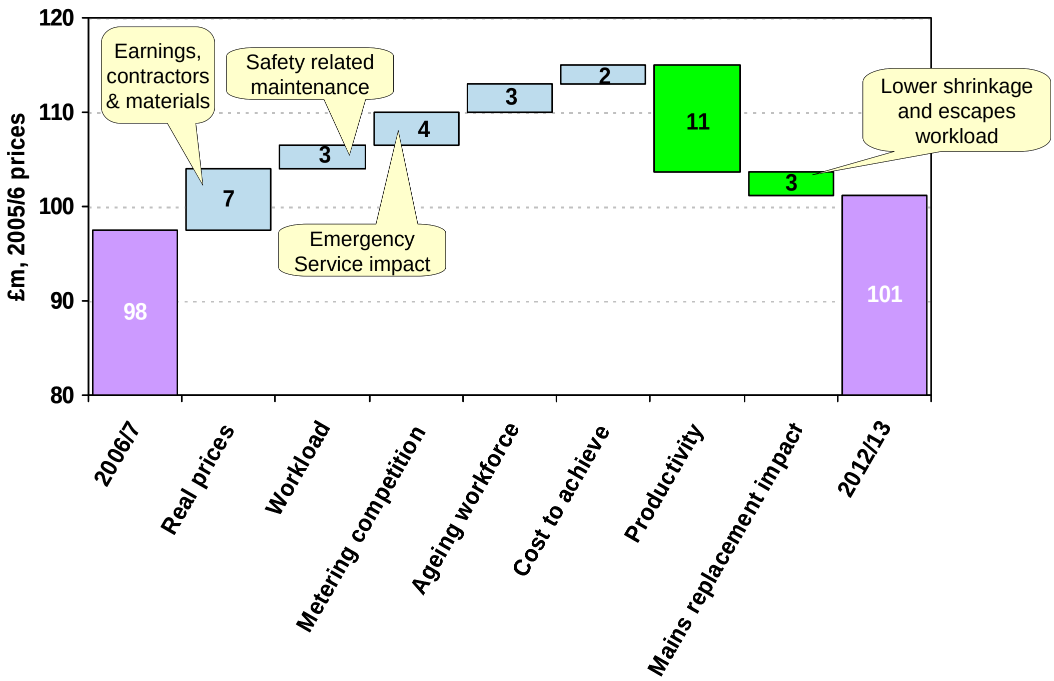
- Uses 2006/07 as the base year, since this is the first year in which cost stability can be evidenced post network start up;
- Includes appropriate and relevant regional factors – further detail has been provided in question three, (paragraphs 44 to 48), and
- Sets an efficiency target which recognises that the scope for radical change is limited going forward. The top down approach used by Europe Economics overstates the potential frontier shift, in part as a result of their assertion that a continued privatisation effect is evident, as shown in the First Economics report, submitted as a supplement to this response.

A top down approach will mitigate the risk of 'cherry picking' that is inherent in a bottom-up approach. The bottom up analysis should however be used to cross check the outcome.

ii. Provide an additional allowance for new costs, premised on Ofgem's 'judgement based on evidence' approach using all available information. These new, external costs include tightening waste management regulations, higher cyclical maintenance, the impacts of an ageing workforce on productivity and training costs and the impact of increasing metering competition.

iii. Figure 1 shows these new costs and how National Grid is targeting significant improvements in productivity and other areas that largely absorb their impact. At present, the consultants' reports take or extend these benefits and ignore the new costs, which would lead to an unbalanced and impractical outcome.

Figure 1: Average opex per National Grid network



26. In deriving an efficiency target using a top down approach, Ofgem should ensure that the most appropriate cost driver is used. Our experience is that customer numbers is the single factor with the strongest correlation to a GDNs' operating costs, being a good metric for both operational activities (via gas demand) and overhead functions (via GDN size). The correlations of the best drivers with the eight GDNs' costs, using 06/07 data from Ofgem's draft report by Europe Economics, are shown in table 1 below:

Table 1: Cost driver correlation

	Customer numbers	Throughput	Network Length
Correlation to costs	97%	89%	74%

27. Our experience of GDN comparisons also shows that selecting any single driver will tend to under or over-estimate benchmark costs in one or two networks, usually those at either extremes of customer density. Ofgem must balance complexity with the appropriate degree of reflectiveness. Length of main (or more accurately, length of metallic main) does drive a proportion of a GDN costs and so using customer numbers as the driver may not capture all nuances associated with less dense networks such as Wales and the West or East of England. For similar reasons, throughput does not accurately model London. We do not however believe the materiality is sufficient to warrant the complexity of introducing an additional variable to what is clearly the best statistical fit of customer numbers. No single driver alone will accurately capture the very significant additional costs within London, as discussed in paragraph 48.

The use of glidepaths

28. It is also important that the efficiency target and speed at which it is achieved are reflective of the limited flexibility within a GDN's cost structure. We support the approach of setting the target at the upper quartile rather than the frontier, particularly given the comparison issues raised in paragraph 23. In considering the speed at which the target should be reached, Ofgem identify a number of options, namely full gap closure, the use of a glidepath or allowances premised on historical costs.

29. A full gap closure approach might be appropriate if there was a high level of confidence in the analysis, i.e. >90%. Whilst the analysis in the fourth consultation document is generally directionally correct, the data quality issues mean that confidence levels are significantly lower than this and the use of full gap closure would be likely to set unachievable targets. As a result, we do not support the full gap closure approach. Instead, the approach taken by PB Power, i.e. the achievement of 70% of the identified target over a 5 year period, seems the most appropriate.

30. The speed of change is an important factor that must be considered, given that new systems and structures all take time to develop and implement particularly in organisations dominated by safety considerations. There is also no further opportunity for major reorganisation within National Grid's networks and so, going forward, change will be incremental in nature.

31. We note that Ofgem express concern that a glidepath approach may allow inefficient GDNs to earn a greater level of return than those at the frontier if they are able to remove inefficiencies faster than anticipated. We do not believe this to be a practical concern as the type of efficiency initiatives likely to remain in the armoury of a GDN will generally have lead times of at least two years for full fruition, and require significant costs to achieve

Question 2: Is there a case for making adjustments to allowances for real price effects, specifically direct labour, contract labour or materials?

32. We believe that there is absolutely a case for adjusting allowances for real price effects. All GDNs are facing real cost pressures over and above that set by RPI, which are increasingly difficult to mitigate. It is only right that these are reflected in the outcome of this review to allow GDN's to finance their activities.

Direct labour real price effects

33. Contrary to the analysis presented within the consultation document, both the work done by Hay and that by Inbucon on behalf of Ofgem during TPCR validates our assumption of RPI+2 in relation to direct labour costs, particularly when trend analysis is used rather than a spot year. Labour wage rates have consistently been running ahead of RPI over many years, with London costs forecast to increase at an even faster rate.

34. Looking forward, we believe our forecasts are robust. RPI+ comparisons are a long established expectation built into pay settlements and average earnings increases across industry. Whilst there is no single, definitive methodology or leading indicator for forecasting future levels, the following underpin the forecasting of our future employment costs:

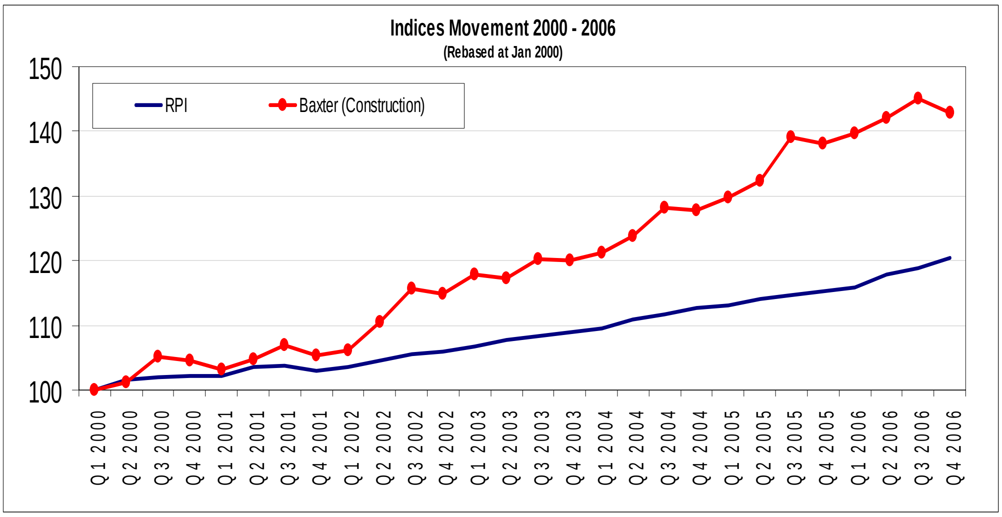
- Average earnings growth in the private sector for a minimum 5 year period,
- Consolidated forecasts for future earnings growth (those produced by HM Treasury for example),
- Previous average earnings growth for National Grid employees, and
- Our individual circumstances and employee context (e.g. demographic profile, skills shortages and the continued expectations of our key Trade Unions for RPI+ settlements)

35. Evidence premised solely on recent average earnings, or a single spot year, will only increase the risk that projections may be significantly above or below actual levels. Headline pay settlements, for example, are likely to understate actual salary increases.

Contractor real price effects

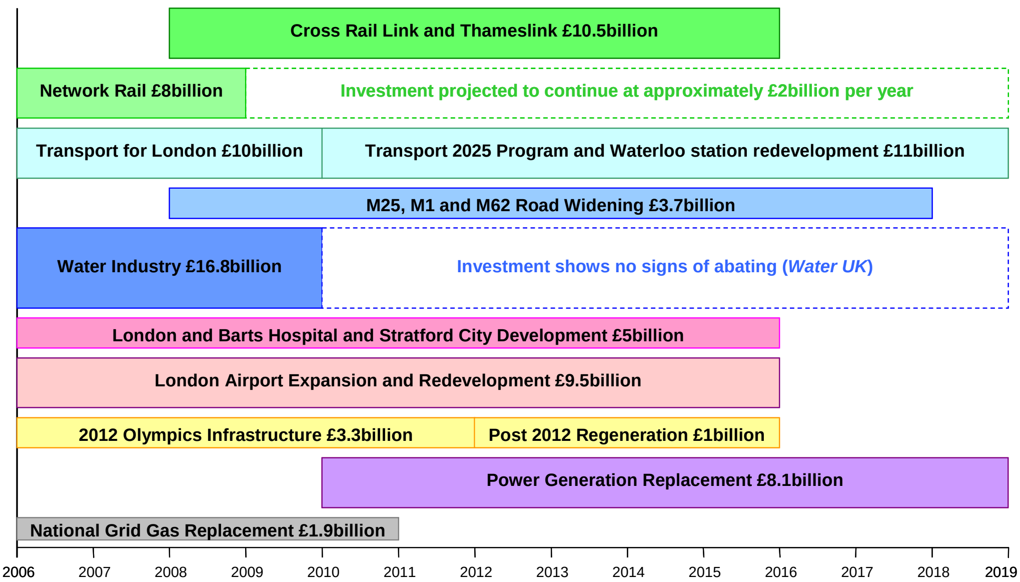
36. All GDNs are heavily reliant on the use of contractors in order to deliver their investment programmes efficiently and effectively and account for approximately 80% of National Grid's total investment spend. Over the prior price control period, we have faced an increase in contractor prices in excess of RPI, resulting in an additional £200m of cost over and above that included in the allowances shown below in figure 2.

Figure 2: RPI and Baxter Indices (2000 – 2006)



37. Inevitably, questions arise as to whether a re-profiling of workload is appropriate in the hope that the impact of the current levels of construction demand on contractor prices will abate for future reviews. We see no current market signals or evidence to suggest that a slow down in contractor prices is likely in future periods, shown below in figure 3.

Figure 3: The economy continues…



38. It is imperative that reflective contractor rates are included in any allowance. With Baxter not available on either a forecast or regional basis, we suggest that the independent report prepared by EC Harris is a robust basis for forward looking allowances. This forecast is not only entirely reflective of gas distribution activities, but also allows for regional comparisons and is historically comparable to Baxter, which has averaged around 1% above the EC Harris index over the past seven years, and is line with PB Power's recommendation of RPI+2.25%.

London contractor price increases

39. Over the last seven years, contractor prices in London have risen at least 1% a year above the national average and EC Harris is forecasting an on-going differential of 1.5% a year, driven by continuing high construction demand in the capital, including not only the Olympic development but also Cross Rail, Stratford City development and Transport for London schemes.

40. Consequently, we believe it is not credible to apply a single rate of real contractor price increases across all GDNs as PB Power suggest, as this ignores the faster rate of contractor price increases in London, increasing the risk of underfunding in the south whilst over funding elsewhere. An average annual rate of increase of RPI+3.75% should be used instead, as evidenced by both past experience and independent forecasts

Protection Mechanism

41. We continue to believe that the introduction of some form of protection mechanism is warranted in relation to extreme movements in contractor prices, particularly given the modest assumptions included within our plan. We propose that a mechanism be established which allows for adjustments if the cumulative differential between allowances and a pre-defined index, such as Baxter, becomes material across the period. A symmetrical mechanism would ensure that customers and GDNs are protected from any extreme movements in prices, whilst still maintaining appropriate exposure to price risk. Any payment to or from the GDNs could then be agreed at the end of the price review as part of a 'logging up' mechanism.

Materials Costs

42. We note that further consideration is being given to real growth in materials costs. Many of the materials used by GDNs in the course of their operations are oil-based e.g. PE pipe and fittings, fuel oil, bituminous products. Consequently, it would be surprising if prices for such materials moved in line with RPI, as suggested by BCIS. Our forecasts reflect real price effects for materials in the range of 1% to 2% p.a. above RPI for these categories of materials.

43. PB Power acknowledges that a reasonable rate of increase for materials prices would be 1% above RPI, and certainly not in line with RPI.

Question 3: Is there a case for making adjustments to allowances for regional factors and if so what approach should be adopted?

44. To a certain extent, regional variations in GDN costs are inevitable, but the key as to whether these should be applied across **all** GDNs is;

- the degree of quantifiable evidence available, and
- the level of materiality.

Ofgem must assess possible regional factors, subject them to the above tests and then decide whether to apply them purely in relation to London and the South East or on a network wide basis.

Regional Factors in Investment

45. We support the approach as proposed by PB Power in relation to investment spend, i.e. regional factors applied to all networks, as investment costs are generally dominated by local labour and/or contractor resources, for which reliable, regional indices are available. PB Power has based its regional factors on the new housing indices from the Building Construction Information Service (BCIS) which is not wholly appropriate for the basket of activities undertaken by the gas industry. We have looked at a number of alternative sources of regional factors in an attempt to validate the BCIS indices as shown in table 2.

Table 2: Investment regional factors

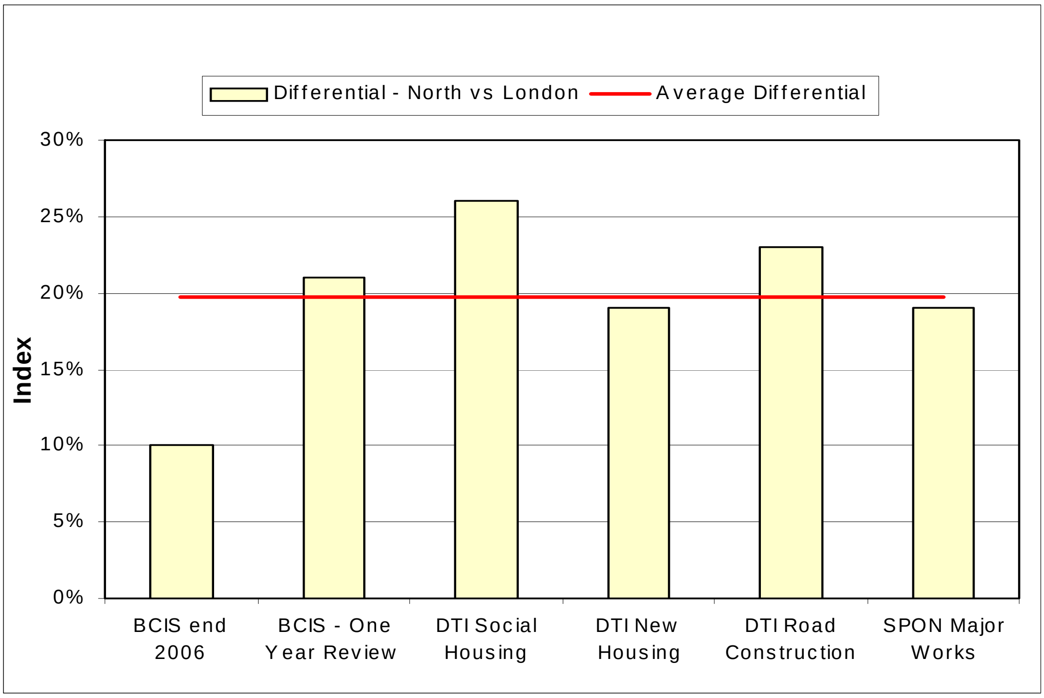
Index	**WW**	**NO**	**SC**	**SO**	**EoE**	**Lon**	**NW**	**WM**
BCIS – PB Power	0.96	1.01	0.99	1.06	1.00	1.11	0.93	0.94
BCIS – Ofgem*	0.96	0.95	0.90	1.08	1.00	1.16	0.97	0.95
Social Housing (DTI)	0.99	0.92	-	1.07	0.97	1.18	0.92	0.92
Non-Housing (DTI)	0.95	0.93	0.95	1.07	1.04	1.12	0.93	0.98
Road Construction (DTI)	0.95	1.00	-	1.15	1.00	1.23	1.00	0.86
Major Works Measured Rates (Spon Price book update)	0.96	0.95	0.93	1.06	0.98	1.14	0.96	0.95
Average	**0.96**	**0.96**	**0.94**	**1.08**	**1.00**	**1.16**	**0.95**	**0.93**

*As used in the extension year review

46. It is clear that there are material variations in contractor costs around the country and that the type of construction activity undertaken adds a further element of variability. It is important, therefore, that this is taken into account when undertaking any form of GDN benchmarking and when setting appropriate allowances for each GDN. Whilst no single index is a perfect fit

for gas distribution activities, an average of the above may be appropriate. By way of example of the outlier nature of the spot BCIS index, the various indices shown table 2 above show that a differential of around 20% would be expected between costs in London and the North of England (which is also in line with our operational experience) and yet the latest BCIS factors have a differential of just 10%, as shown in figure 4.

Figure 4: Variation in regional indices

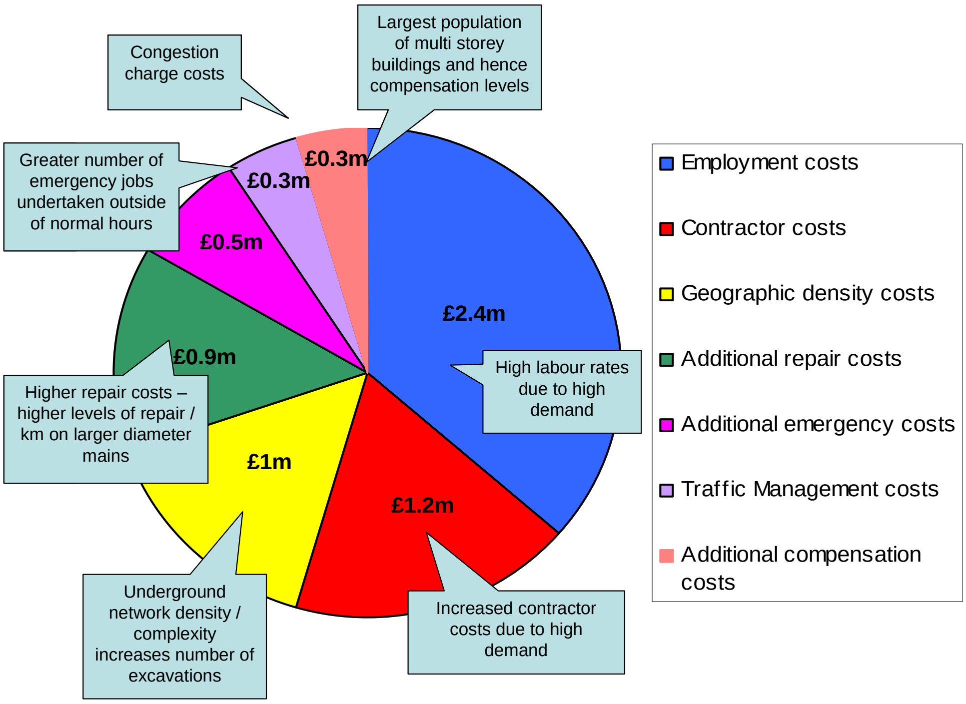


Opex

47. Operating costs are more diverse in their makeup than investment, in terms of type, location, delivery strategy and asset factors, and this makes compensating for regional factors to the same degree as investment more difficult. Accordingly, it may be appropriate on opex to only adjust those networks where costs are materially and unequivocally impacted by regional factors.

48. Within National Grid's four networks, London is significantly more expensive to run than an average network because of the specific factors outlined in figure 5. These factors have been clearly evidenced and quantified and must be included in any allowance determined by Ofgem.

Figure 5: London regional factors



Should Ofgem decide to apply regional factors to the opex of all networks, we have also provided information that outlines why:

- the high volume, size and type of mains and above ground assets in the North West also means that this network is more expensive to run than average;
- that asset and geographic factors in East of England effectively cancel each other out, making it broadly in line with average costs; and
- West Midlands network is cheaper than average, due to its geographic density and favourable asset make up.

Question 4: Should we adapt our pension principles to address the forecast defined benefit pension contributions, which are both extremely high and vary widely across GDNs (despite funding very similar benefit packages)

Question 5: Should we change our pension recovery mechanism in order to avoid distorting incentives between making salary and non-salary cost savings?

49. Ofgem's proposal to adapt the pension principles in the manner described appears to comprise the following main propositions:

- deeming of an ex ante efficient level of pension costs through the next price control period for remuneration within that period could be done in one of three ways ('Options' 1, 2 and 3);

- regardless of the option chosen for deeming an efficient **ex ante** level of pension costs, any future reconciliation with actual pension costs should be qualified to the extent that 'stranded surpluses' had been created in the relevant pension funds; and
- the mechanism used in other energy network price controls for reconciling price control allowances for pensions with actual pension costs should be refined so as not to give perverse incentives with respect to total operating costs.

Estimation of efficient pension costs through the next price control period

50. Ofgem has proposed three options as to how price control allowances should be set with respect to pension costs. Specifically, it is suggested that the allowances should be based on:

- a benchmark contribution rate derived from analysis of GDN and comparable company contribution rates ('Option 1'); or
- "the contributions that would be made by a notional GDN with comfortably investment grade financial position" ('Option 2'); or
- as now, the likely pension contributions of the company in question, subject to checks on the actuarial basis of those contributions ('Option 3').

51. In our view, both Options 1 and 2, but particularly Option 1, would conflict with an important principle which Ofgem has followed in previous price reviews for electricity and gas transmission and for electricity distribution. This is that, although pension costs have been accorded different revenue treatment to that for overall operating costs, any consideration of an efficient level of pension costs has not been in isolation from the level of total remuneration received by employees (or, even more broadly, from the level of total controllable operating costs).

52. On this basis, benchmarking of pension contribution rates alone would ignore any trade-offs which an efficient company might make between pensions, non-pension remuneration and other operating costs. This problem would be particularly acute for Option 1 because Ofgem suggests that this would involve benchmarking across not only the GDNs but also other 'comparable companies'. It is not clear what might constitute other comparable companies but it is unlikely that these would need to incur equal non-pension costs or have comparable benefit structures to the GDNs.

53. For these reasons, Ofgem should choose Option 3 – i.e. an analysis of an efficient level of pension costs for the individual company – as the basis for deeming an efficient level of pension costs for that company for the next price control period.

Ex post reconciliation with actual pension costs and the treatment of 'stranded surpluses'

54. Although this price review will result in a revenue allowance in respect of pension costs for each of the GDNs through the next price control period, the review will also decide what happens in the event that actual pension costs turn out differently from what has been assumed. In the wake of the energy transmission and electricity distribution price controls, the position has been that, in the absence of inadequate stewardship of the relevant pension schemes, Ofgem would expect to adjust revenue in future price controls to take account of divergence between companies' actual pension costs and what has been assumed at the previous price review.

55. In the current consultation document, Ofgem proposes an important change to this process. Specifically, it is suggested (paras 3.114 and 3.115) that Ofgem would take account of any 'stranded surplus' in pension schemes when setting pension revenue allowances at future price reviews. By 'stranded surplus', Ofgem means that pension fund trustees, supported by recent pensions legislation, might choose not to reduce future employer contributions in the light of a scheme surplus, especially when the highly leveraged financial structure of the company in question might be thought to weaken the employer's future willingness and/or ability to increase future employer contributions to deal with any future scheme deficits. In this world, the surplus would be locked into the pension scheme ('stranded') and not available to, for example, either increase dividends or reduce prices.

56. The circumstances in which Ofgem would deem surplus to be stranded – and therefore intentionally set revenue allowance to under-recover against expected employer pension contributions – is not totally clear from the document. For example:

- Para 3.114 of the consultation document implies that, in an Option 3 world, adjustment would only happen if the surplus was as a result of high contribution rates – but, in an ex post sense (and the proposed adjustment **is** an ex post adjustment), a surplus might be seen as **necessarily** implying that the contribution rates had been set too high.
- If the problem is that contribution rates turn out to be set too high **in the light of information available at the time of this price review**, then this is a problem which Ofgem should be addressing through analysis as part of this review and the appropriate setting of allowances (in our view, within an Option 3 framework). One of the features of the pensions issue is that the estimation of future pension contributions is considerably more transparent and easier to analyse (always allowing for the range attributable to the judgements made by professional actuaries, judgements which Ofgem has always sought not to second-guess) than projections of some other elements of network expenditure.
- It is not clear how Ofgem would separately identify the surplus created by ongoing contributions within the period from any surplus arising from funding of benefits accrued before the period.

- It is also not clear how far the proposed mechanism would apply only to highly leveraged companies, which would be seen as having invited a level of prudence on the part of pension trustees which might not have been triggered if those trustees were more confident of the long term solvency of the business in question.
- In the context of the known difficulty of fixing a point (as opposed to a range) valuation for pension fund liabilities, it is not clear how material a point surplus would have to be to trigger the proposed adjustment.
- Finally, a pension scheme is a long term arrangement. If a surplus arises then it will reduce the chances of customers needing to fund a deficit at a future time. To disallow part of the surplus would produce a result which is disproportionately weighted in favour of customers

57. In other words, it is our view that the proposed mechanism:

- would create uncertainty about the outcomes of future price reviews (and therefore increase the costs of financing of GDNs), not least because Ofgem would seem to be giving itself substantial discretion in how the proposed mechanism would work, both in relation to materiality and in relation to how it would distinguish between 'good' pension fund surpluses (which would not require an adjustment) and 'bad' pension fund surpluses (which would require an adjustment). This discretion could affect the trustees assessment of the strength of the employer's covenant causing them to seek stronger funding; and
- is unnecessary because the real issue here is the ex ante determination of appropriate revenue allowances - and pensions is an area where setting appropriate allowance is considerably easier than in respect of some other areas of network expenditure.

58. We believe that in order to keep pension costs low, Ofgem needs to create a stable environment for the recovery of pension costs to support the trustees' assessment of the strength of the employer's covenant.

Further refinement of the ex post adjustment mechanism

59. Ofgem suggests (para 3.117 of the consultation document) that an ex post reconciliation which compares actual cash pension contributions with the cash allowance set at the previous price review could distort incentives to reduce different categories of operating cost. We agree with this point and do not disagree with Ofgem's proposed solution for the following reasons:

    - A purely cash based approach will create a perverse incentive to carry out as much activity as possible within regulated business even if outsourcing activities is more efficient

- A cash based approach will reduce the strength of opex incentives
- A payroll multiplied by percentage allowed method will better reflect the underlying intentions of the Pension Correction Mechanism (PCM)

60. Furthermore, we believe that it is important Ofgem ensure that the PCM is carried out for all relevant price controls, even if the assumed contribution rates in a particular scheme prove to be correct. These issues are discussed in turn below.

Perverse incentive

61. A cash-based PCM will create a perverse incentive to carry out activities within the regulated business. If an activity is outsourced to a third party, the pensions costs of the employees will transfer to the provider of the service and be replaced by a charge for providing the service. Under a cash based pension mechanism, the allowance would have been calculated including these outsourced pension costs, whilst the actual cash pension costs will be below the allowance because the pension costs are now borne by the outsourcing company rather than the regulated entity. Under a cash-based PCM therefore, Ofgem would claw back this excess pensions allowance at the next review. Consequently, the company would only outsource the activity if the savings were sufficiently large to offset the lost pension contributions.

62. The scale of this disincentive can be assessed by looking at the finance function of National Grid, the sort of activity that some companies choose to outsource. Staff costs make up approximately 80% of National Grid's finance costs, and pension costs are approximately 20% of staff costs on a forward looking basis. As a result, unless the outsourcer could offer savings in excess of 16%, it would not make sense to outsource the activity. Furthermore, a cash-based PCM would also create an incentive to insource a range of activities. This could affect decisions relating to the balance between direct employees and agency staff or the renewal of existing outsourced contracts.

63. A PCM where the allowance was calculated on the basis of actual payroll multiplied by allowed rate overcomes this drawback. A worked example based on the above is provided in Appendix 1.

Strength of Opex Incentives

64. A cash-based PCM will also serve to reduce the strength of incentives on companies to reduce operating costs as the costs (benefits) of pensions costs exceeding (outperforming) allowances will be clawed back by Ofgem.

Intention of the PCM mechanism

65. More philosophically, pension costs are subject to a correction mechanism, where normal opex is not, because the nature of pensions costs means that costs can be transferred between different price controls and that customers or shareholders could benefit twice. For example, if Ofgem allowed costs at an ongoing rate of 30% and the company shortly afterwards negotiated a reduced contribution rate of 4% then shareholders will benefit from the lower contributions within period. However, it is possible that in future this reduced contribution rate will lead to an underfunding of the scheme and an associated deficit. In the absence of a PCM, customers would fund this deficit, providing the company with an unjustified windfall.

66. The purpose of the PCM is therefore to prevent customers or shareholders from benefiting twice from what are essentially timing differences between the money paid into the scheme and the liabilities being accrued.

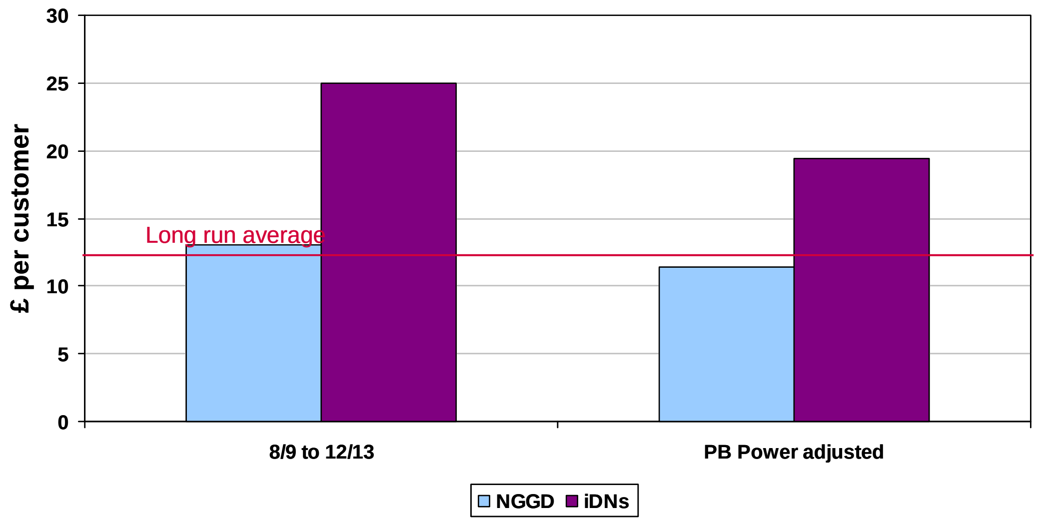
67. However, pension costs can also be reduced by lowering the level of underlying pensionable payroll. If National Grid reduces payroll costs below those assumed, it will indeed pay less money into the scheme - but it will also have taken on lower liabilities. All other things being equal, the net effect will be that there is no surplus or deficit created. Rather than being a timing difference, this would in fact be a genuine saving. In that scenario, these savings are more like general operating cost savings and it therefore seems appropriate that shareholders benefit from the efficiency for the five years of the price control and that these benefits are then passed on to consumers in the usual way.

Chapter Four: Capital and Replacement Expenditure Analysis

Question 1: What are your views on PB Power's adjustments to the GDNs' forecast capital and replacement expenditure?

68. In our opinion, the adjustments proposed by PB Power do not appear to have taken full account of the different investment strategies being taken by GDNs. As an example, figure 6 overleaf compares average annual net capex per network for National Grid’s four networks with that for the combined sold GDNs. The significant variance between the forecasts for 2008/9 to 2012/13 suggests that there may be differences in investment strategies, particularly in terms of an opex/capex trade-off and/or inconsistencies in assumptions.

Figure 6: Average Annual Net Capex per Customer



69. Although PB Power's adjustments seem to support this view, with the percentage reduction for the independent networks being roughly twice that proposed for National Grid's networks, it is unclear whether the resulting projections are fully comparable.

70. Taking new storage provision as an example, PB Power has used a benchmark capex value of £50 per cubic metre and, provided that storage related capex in GDN's bids are less than twice this value, no adjustment is applied. **On this basis, National Grid's investment could have been £440m, or £9 per customer higher**

71. This approach to the assessment of storage capex requirements appears to present a perverse incentive to GDNs to decommission existing holder storage and build high pressure pipelines solely for storage purposes. Over the last two years we have evaluated our existing storage facilities (both individually and as a population) and have determined that the economics of gas holders can be very compelling and, in most cases, existing assets should be maintained through refurbishment and major maintenance.

72. PB Power's benchmark capex value for storage on an annualised equivalent basis is £5-10 per cubic metre per year compared to their proposed efficient level of storage opex cost of just 60p a year. Our opex submission was equivalent to £2-4 a year, incorporating necessary major maintenance (cyclical painting and refurbishment). The disallowance of a significant proportion of our proposed opex means that we are encouraged to replace this efficient form of storage with capacity from what appears to be significantly more expensive capital schemes. We urge Ofgem to review the overall economics of our storage opex bid, in light of the above analysis, as they form their Initial Proposals.

73. Our other chief concern relates to PB Power’s proposed adjustments to mains and services replacement workload. Our concerns are presented in our response to question three of this chapter.

Question 2: What are your views on PB Power's general approach to the assessment of costs?

74. Unlike opex, the drivers for investment vary significantly depending upon the type of spend e.g. connections activity is driven by consumer demand for new connections whilst LTS is driven by capacity and/or storage requirements. As a result, it would be inappropriate to apply a single approach to investment assessment and we therefore support PB Power's approach of using a variety of methods dependent upon the specific activity.

75. However, we believe that PB Power has been less successful in some areas than others, not least in their decision to not undertake detailed, project specific assessments of LTS capacity schemes but instead rely on a desktop analysis that appears to produce results with very large margins of error, as discussed in paragraph 70. We provide further comment on the impact of project specific factors in our response to question three below.

Question 3: What are your views on PB Power's approach to the cost assessment for each activity?

LTS and storage capex

76. In addition to specific comments we have made in our response to question one, we support the approach to remove expenditure that is inconsistent with Ofgem’s guidance on NTS capacity, i.e. that GDNs should assume that they will be able to continue to purchase existing NTS capacity at administered prices and that additional incremental capacity would be available through user commitment.

77. However, it may be difficult to identify capex which is primarily related to exit/interruption and, therefore, it is unclear whether the adjustments made have taken full account of any inconsistencies between GDNs, given the scale of variation in GDN forecasts that remains.

78. We also note that further consideration will be given once the form of enduring NTS capacity arrangements has been decided. Clear guidance needs to be given as soon as possible in order to allow GDNs time to develop updated forecasts for submission to Ofgem in July in line with the timetable for GDPCR.

79. PB Power's adjustments to our forecasts for LTS and storage principally relate to the deferral of two major pipeline projects, reflecting a different view regarding the timing of investment to meet storage requirements. We believe these adjustments ignore two fundamental aspects of our submission. Firstly, the current and acute over-reliance on the NTS for storage within North West and secondly, the crucial inter-relationship of a proposed pipeline project with the replacement of the large diameter cast iron medium pressure mains in London and the implementation of the wider London Supply Strategy.

Mains reinforcement

80. PB Power has limited its adjustments to GDN forecasts to price, using regression analysis combined with an 2% assumption for year-on-year performance improvements. To determine future capex requirements on the basis of regression analysis can result in unrealistic proposals where workload volumes are relatively small, as is the case in this activity for our networks. Project specific factors can materially distort the results and a review of the limited number of larger projects in this area would be a more appropriate technique. As an example, it is unrealistic to assume that the cost of a single mains reinforcement project of 5km undertaken largely in rural conditions would be the same as that for 10 projects of 500 metres each in heavily built-up areas.

81. Additionally, as these workloads are both small and driven by customer demand, each project tends to be geographically dispersed from the next, adding a premium to contractor rates for mobilisation and demobilisation. Consequently, the scope for efficiency improvement is limited and would certainly not be greater than that for mains replacement where PB Power has assumed annual efficiency improvements of 1.75% can be achieved.

Governors

82. It is not clear what, if any, adjustments have been made in this area, other than to remove all expenditure relating to the replacement of governor installations that do not incorporate safety devices to protect the downstream network. PB Power acknowledges the requirement to replace these installations, however, they contend that the necessary replacement expenditure should have been incurred some years ago and have therefore disallowed all expenditure necessary to remove these governors over the period 2008/9 to 2012/13.

83. To disallow capex on the basis that it "should have been incurred some years ago" is wholly inappropriate. If the reason for PB Power's recommended disallowance is a fear that GDNs could somehow receive funding twice for this work then we would comment as follows:

- The price control process already has an in-built correction mechanism whereby if no actual expenditure has been incurred then nothing is added to the RAV at each price control true-up, such that there is no risk of being paid twice;
- Notwithstanding this, no allowance was made for the replacement of these governors in either of the last two regulatory settlements;

Connections

84. PB Power's recommended adjustment to connections capex is equivalent to the removal of one year's investment in this area. The scale of this adjustment is of great concern particularly given the significant overspend that occurred in this activity during the 2002/3 to 2006/7 price control period, largely as a result of flawed assumptions at the time of the last review.

85. From a net capex perspective, virtually all the proposed reduction relates to the non-competitive, existing housing market where the work is driven by customer demand and GDNs have little, if any, choice but to undertake the work. PB Power has presumed that significant year-on-year efficiency improvements can be achieved. This is not realistic for such a mature activity, particularly so for one with a rigorous standards of service regime where jobs are one-off in nature and geographically dispersed.

Non-operational capex

86. It is reassuring to note that PB Power agrees that GTMS is obsolete and that its replacement via a collaborative approach is the most efficient and should be fully funded. We agree that capex related to SOMSA exit should be disallowed in accordance with the principles set out by Ofgem in its third consultation document.

Mains and services repex

Workload reductions

87. Regarding the mains related workload adjustments (which have a knock-on effect on service workloads), we would comment as follows.

88. The proposed reduction in the length of iron mains to be decommissioned each year does not recognise the HSE's requirement to remove all iron mains within 30 metres of a building "as soon as reasonably practicable". We expect to have decommissioned 1,820km of policy mains in 2006/7, in line with previous tripartite agreements with the HSE and Ofgem, thereby demonstrating that it is *reasonably practicable* to achieve this level of decommissioning.

Consequently, our repex plan is based on decommissioning a similar level of iron mains each year.

89. We could accept a lower level of workload provided the HSE agree, with reference to the Pipeline Safety Regulations. It would be essential to review any reduced level during subsequent price control reviews to ensure the 30/30 programme was still on-track to be completed to a timescale acceptable to the HSE.

90. PB Power's adjustment to downsize the diameter mix of mains to be installed appears to ignore the widespread downsizing already built into our plans. It also takes no account of the forecast upward shift in the diameter mix of mains to be decommissioned (with the consequential need to lay mains of larger diameters) and would result in a significant reduction in system capacity requiring reinforcement within a short period of time, with consequent disruption to the public and additional cost to customers.

91. Moreover, scaling back the length of installed mains on the basis of an arbitrary abandon to lay ratio ignores the incompatibility of high insertion rates (with associated lower unit costs and environmental benefits) with a high abandon-to-lay ratio. In addition, reducing the length of main laid will increase the length and cost of services, some of which will need to be laid across the road. Notwithstanding this, reducing the length of mains to be laid for a given length of mains decommissioned, does not change the number of properties impacted and, hence, it is incorrect to adjust the number of services to be relaid/transferred.

Contractor inflation

92. In terms of price, the application of a single rate of contractor inflation across all GDNs makes no allowance for factors specific to London and is not credible. Over the last seven years, contractor prices in London have risen at least 1% a year above the national average and EC Harris is forecasting an on-going differential of 1.5% a year. We have commented in detail on this subject in our response to question three, chapter two.

Question 4: Is it appropriate at this time to reconsider the approach to prioritisation within the risk model for the Mains Replacement Programme and should the approach to encroachment and diversions be amended?

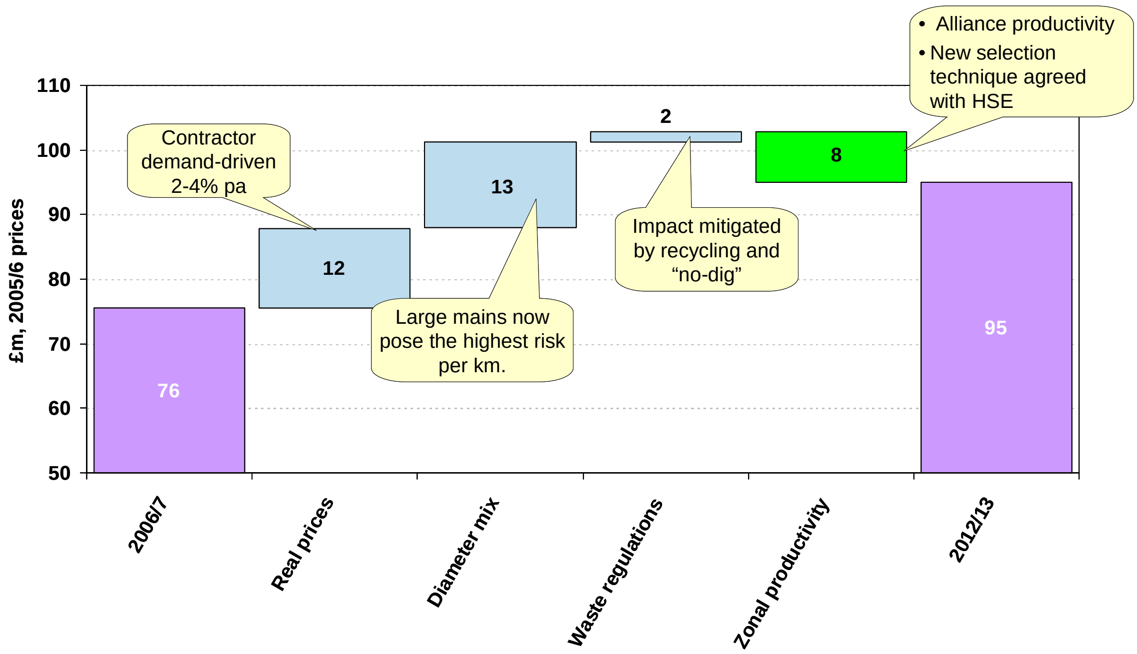
93. The repex programme is the biggest single component of GDN costs. As such, it is right to keep such a large scale programme under review to ensure that the incentives remain appropriate and deliver benefits to customers.

94. The presentation of National Grid's approach to mains replacement in paragraph 4.51 of the consultation document could suggest that total costs in the next period will be significantly higher than they have to be due to some elective acceleration of work. This would not be an accurate representation. The length of work accelerated over the next formula period totals 85km, or 0.8% of the overall programme. Using typical unit costs, this will cost around £12m. This acceleration has enabled us to agree a revised selection technique with the HSE that we estimate will deliver customer savings of £170m over the next five years.

95. Neither has National Grid chosen to accelerate the replacement of large diameter mains. Pipes greater than 12" in diameter do represent a greater proportion of the planned workload than they did during the last five years, but this is primarily a reflection of movements in the risk profile and the overall diameter mix of our remaining iron mains population. Further detail on these movements is given in paragraphs 37 to 39

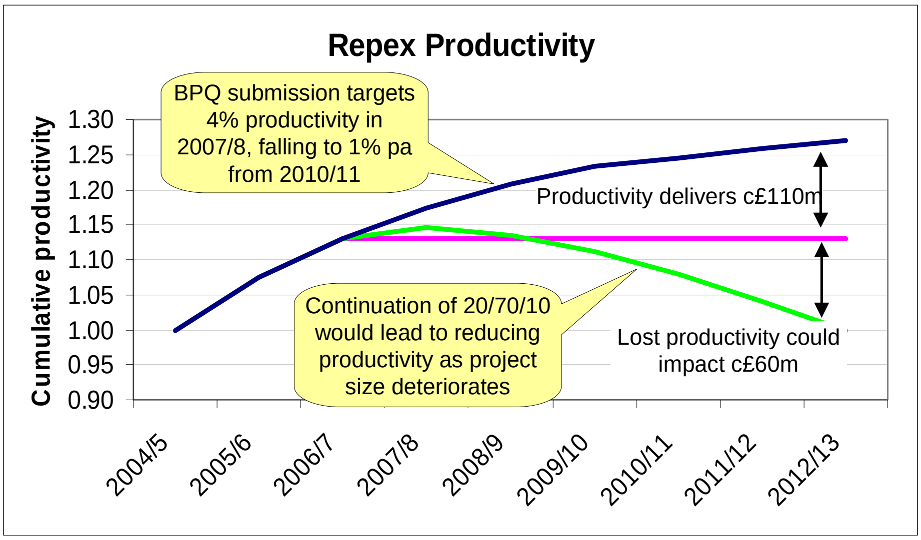
96. This change in the diameter mix of mains decommissioned is the principal reason, along with real contractor price increases, for the increase in the cost of our repex programme compared with the first 5 years, as illustrated in figure 7 below.

Figure 7: Average Net Repex per Network



97. Moreover, this increase would have been significantly greater had we not been able to move to a "zonal" approach, as shown in figure 8 overleaf. Continuation of the "20/70/10" approach to pipeline selection would result in reducing productivity as average project lengths fall, increasing expenditure for the 5 years by £170m compared with our BPQ submission.

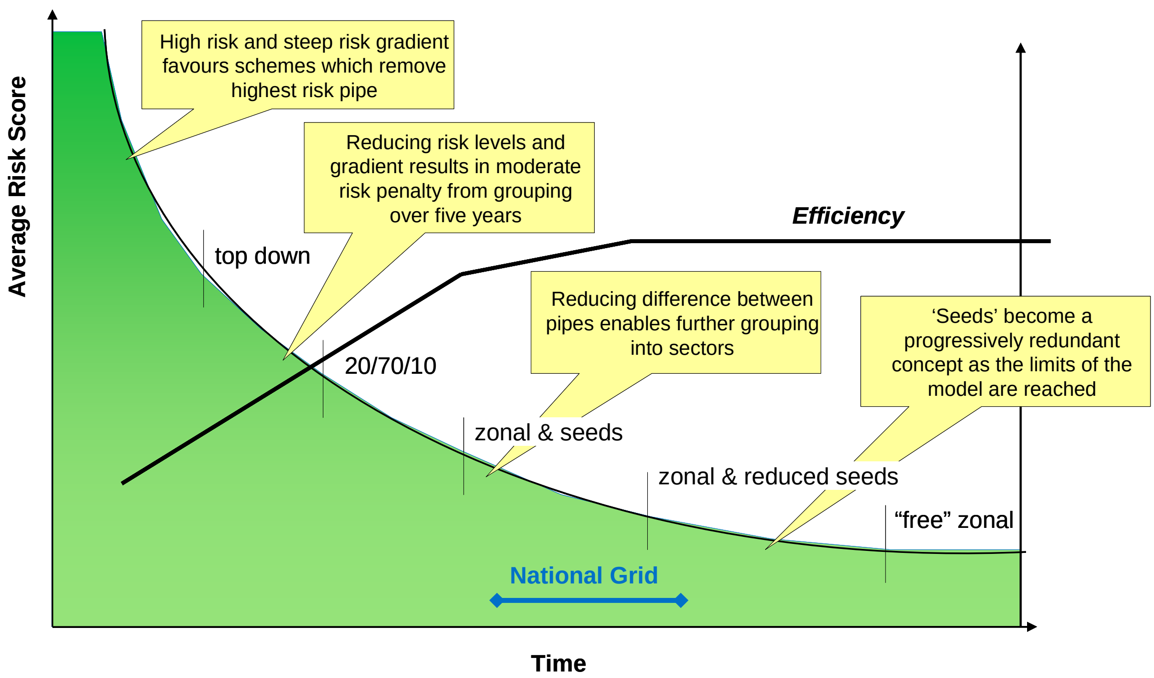
Figure 8: Repex Productivity



Approach to pipeline selection

98. Notwithstanding the fact that GDNs are only five years into the HSE policy programme, the approach to the selection of pipes for decommissioning has already undergone a number of agreed changes as typical risk threshold values have been reduced, as illustrated in figure 9 below.

Figure 9: Approach to Pipe Selection



99. At the outset of the 30 year programme there was a small number of very high risk pipes which were removed on a risk priority basis in order to remove risk at the fastest rate. However, these pipes were typically short length and geographically dispersed, factors which are not conducive to efficient and cost effective working. Once these pipes were removed, the HSE agreed, in May 2003, to a new pipe selection methodology (20/70/10) which would

enable larger, more cost effective, projects to be designed. Under 20/70/10, 20% of work must be from seed pipes (the highest risk pipes), 70% from those pipes that rank for decommissioning within the next 5 years (secondary pipes) with the final 10% of work selected to make projects more cost effective.

100. 20/70/10 was still designed to target the removal of the highest risk pipes and, therefore, the scope for generating larger and more efficient projects reduces each year as lower scoring seed and secondary pipes become more geographically dispersed. The legacy of continuing with projects of reducing size would be to create more fragmentation within the low pressure networks, leading to greater difficulties in managing the replacement programme, and the networks themselves, in the future.

101. In terms of risk removal, typical seed threshold values have been reduced from 800 to 200 over the first 5 years of the programme with the higher risk scores now coming from the larger diameter mains. As the highest risk pipes are removed, risk scores become more homogeneous making it harder to prioritise accurately based on risk. This supports the move to zonal replacement for National Grid’s networks.

102. Under the zonal approach, 20% of the annual workload still relates to the highest risk scoring individual pipe units but the 70/10 element of the programme now comes from the top ranked zones where the risk scores per km are ranked on a zonal basis.

103. As well as being more costs effective, zonal replacement will leave local networks in a much better condition for the future, compared to a continuation of 20/70/10 and allows the consumer benefits from mains replacement to be achieved earlier for parts of the system. For example, local networks would be largely, if not entirely, PE-based, reducing leakage and facilitating pressure elevation rather than mains reinforcement to meet increased demand. This is particularly important if, at some stage during the 30 year programme, tripartite agreement was reached to scale back, or cease, the programme. Alternatively, continuation of the 20/70/10 approach would leave mixed material networks.

Large diameter mains (>12”)

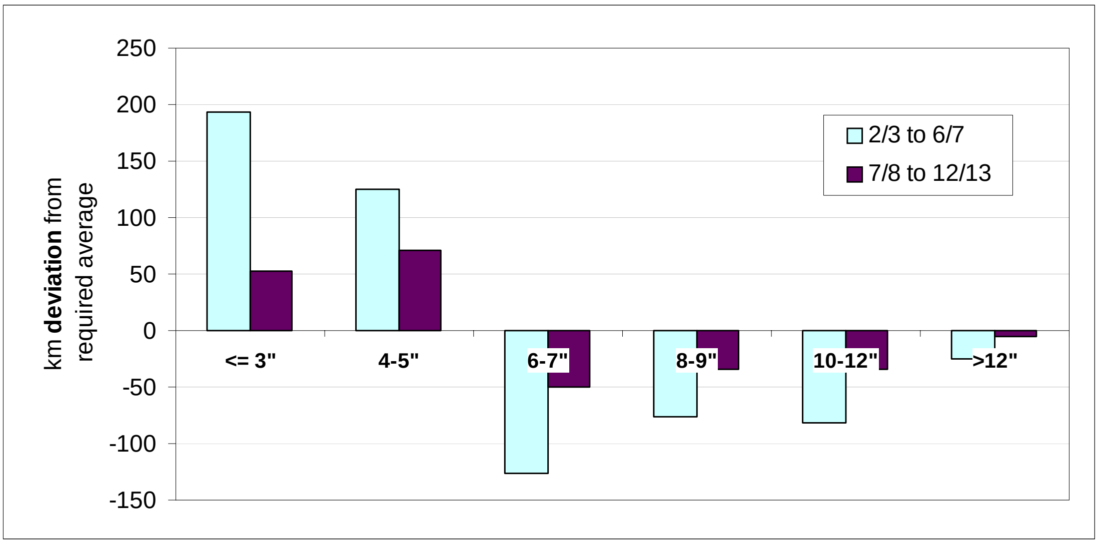
104. Turning now to large diameter mains: at the outset of the current iron mains replacement programme in 2002 a national target of 90km p.a. for >12” mains was agreed with the HSE for Transco’s eight networks, equivalent to around 45km for National Grid’s retained networks. This limited commitment recognised the challenge facing the industry in ramping up resources in the first five years of the programme to meet overall target lengths and the limited resource capability within the industry. Continuing to replace >12” mains at this rate **would take around 70 years to complete the work**. The expectation of the HSE was that

the length decommissioned in these diameters would rise after the first 5 years of the programme.

105. As a result of the relatively low level of replacement of large diameter mains during the first 5 years, this category of pipe now accounts for a higher proportion of the overall risk posed by iron mains within National Grid's networks. Our BPQ submission reflects the replacement of large diameter mains based on risk and at a level consistent with achieving compliance within the HSE timetable.

106. The resultant diameter mix of mains to be decommissioned during 2008/9 to 2012/13 reflects an upward shift from the mix undertaken to date and is closer to the mix of the remaining iron mains population within 30 metres of property, as can be seen from figure 10 below. If the diameter mix of mains decommissioned were exactly proportional to the population then there would be zero variance against any diameter band.

Figure 10: Deviation of Decommissioning Lengths from Average Based on Population



107. From a cost perspective, it is this upward shift in the diameter mix of mains decommissioned (and its knock-on impact on the diameter mix of mains laid) that increases the overall cost of mains replacement, and not the move to a zonal approach to pipe selection, as suggested in paragraph 4.51 of the fourth consultation document.

Other iron mains replacement

108. Our forecasts include around 20km a year per network of other iron mains decommissioning work, over and above the 30/30 policy workload. This workload includes mains that are no longer economic or practical to repair, as well as customer driven diversions. Where these mains are within 30m of property, we would support their inclusion in the HSE policy target.

109. Finally, National Grid currently has around 10,000km of iron mains that fall outside the HSE target. However, as a result of future building development over the life of the programme a proportion of these mains will become within 30 metres of property ("encroachment") and accordingly will require replacement.

Chapter Five: Incentives

Question 1: Is it appropriate to retain the current volume driver?

110. It is our view that the existing 35% revenue driver premised on throughput is not consistent with the criteria of cost variability and controllability set out by Ofgem within the consultation document. Under the current mechanism, revenues vary with throughput by 35%, whereas, in practice, less than 5% of our costs vary with throughput year on year. This misalignment has had a substantial negative impact on GDNs over the current formula period given the consistently warmer than average weather and the lower than expected underlying demand. For National Grid this amounts to approximately £53m over the period when comparing those volumes forecast at the time of the last review, which underpin allowances versus actual volumes.

111. Given the inherent weather effect in forecasting throughput volumes and the subsequent volatility, we agree with Ofgem that it is not appropriate to retain the current volume driver in its present form. At the very least, any exposure should be substantially reduced to be reflective of the small degree of cost variation arising from throughput within the bands of normal weather conditions. Given the subsequent materiality of such cost movements, we agree that it may even be appropriate to remove the volume driver completely. However, Ofgem must be mindful that some cost volatility remains for a given year due to weather effects, in particular, a cold winter could lead to a large increase in the number of gas escapes and thus workload and TMA related costs. This is largely a one-way effect as costs do not readily decline as a result of warmer than normal weather. Therefore, assuming that there is no protection by an uncertainty mechanism to such an event, Ofgem must therefore set allowances that take into account this one-sided risk of higher costs than that seen in recent warm or average weather years.

Question 2: Is it appropriate to implement any of the revenue drivers discussed in this chapter and are there any other drivers that we should consider that are not included in this chapter ?

112. Ofgem rightly identify a number of attributes which should be present when considering the implementation of any additional revenue driver, these being;

- Costs vary materially
- Costs are difficult to forecast
- The variation in cost is out of the GDN's control; and
- The variable can be easily measured and independently audited.

113. We agree with the conclusions reached by Ofgem in relation to the inappropriateness of a capacity or customer number related revenue driver. Whilst clearly the costs of providing capacity vary materially depending on project scope and timescales, associated definitional, implementation and audit difficulties are significant. Similarly, the stability exhibited in customer numbers means that any variation is unlikely to drive significant cost going forward, and therefore does not warrant the added complexity.

114. We note that Ofgem believe that scope for a connections related driver remains premised on experience during the last price control period. We do not believe this to be the case for two reasons. First, whilst absolute connections numbers and net capex (only the first 10 metres are capitalised into the RAV) have been relatively volatile, this can in part be explained by the competition assumptions implied in the allowances, with a better reflection provided by Transco's 2000 BPQ submission. Going forward, Ofgem's consultants validate our assumption that National Grid's connections market share will not vary materially given the existing market development / saturation. Second, significant levels of volatility in connections volumes and costs must occur before the additional revenue delivered is material and hence warrants the additional complexity. A 247% variation in costs for example in 2005/06, as shown in table 3, would only have resulted in an additional annual income of 0.21% (the rate of return and depreciation on an annual basis). The current excluded service treatment for connections remains the most appropriate mechanism to mitigate forecast error.

Table 3: Impact of Connections Driver

Connections Net Capex	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**
2000 BPQ volumes	50,186	46,314	40,353	33,748	30,988
Actual Volumes	65,480	52,785	52,426	48,825	46,427
% Variation	**30%**	**14%**	**30%**	**45%**	**50%**
2000 BPQ costs (£m)	15.1	13.8	12.5	11.1	10.3
Actual BPQ costs (£m)	35.9	26.0	24.9	38.6	21.3
% Variation	**137%**	**88%**	**100%**	**247%**	**106%**
Additional income under revenue driver*	**0.16%**	**0.09%**	**0.10%**	**0.21%**	**0.08%**

* Assumes an annual total allowed revenue of £1.1bn for National Grid's 4 networks, 2.22% annual depreciation and 6.25% rate of return.

Question 3: Is it appropriate to strengthen the capex rolling incentives

115. We concluded in our response to the third Consultation that it would be inappropriate to strengthen the GDN's capital expenditure incentives. This was based upon the difficulty of setting a balanced incentive in an environment where the vast majority of spend is non-discretionary (because it is directly driven by customer and legislative requirements) and where forecasts towards the latter years of the plan are almost certainly going to be inaccurate. This GDN characteristic significantly contributed towards the capital overspend seen in the last price control, 97% of which has subsequently been acknowledged by Ofgem as being both efficient and necessary.

Why is a high powered incentive not appropriate ?

116. We recognise the potential benefits of removing **periodicity in regulatory incentives generally**; however, moving to a five year rolling incentive on GDN capex perversely increases exposure over the periods of greatest forecasting uncertainty. Consequently, and as noted by Ofgem, GDN's would have an incentive to inflate plans to offset this increased risk. In contrast, a benefit of the current approach is that the strength of the incentive diminishes as the forecasting uncertainty increases, protecting consumers and companies from windfall losses or gains.

117. Whilst the perverse incentive to inflate plans could be addressed by the introduction of the Information Quality Incentive (IQI), the mechanism still continues rely on consultants' assessments of submitted plans.

118. Ofgem has also stated that the strengthening of the capex incentive will encourage GDNs to find alternative approaches to deliver their obligations, suggesting that GDNs have significant flexibility with respect to meeting, for example, their security of supply requirements. Considering that the vast majority of a GDNs **capex is non-discretionary and customer driven**, GDNs actually have very little flexibility, as evidenced by the capital overspend during the last price control. If GDN's had this flexibility, they would have restricted capex to be within, or at least much nearer, the allowance.

The power of the incentive

119. If periodicity is to be removed, we believe the power of the incentive should be no stronger than the current incentive ie. 20-30%. We believe a low powered incentive, combined with the two elements of the IQI (i.e. additional income and the subsequent efficiency incentive) would provide more balanced incentives to initially forecast accurately, and then to subsequently deliver against the plans.

120. Given the information asymmetry and forecasting uncertainty, we acknowledge the challenge that exists with regard to setting appropriate capital allowances. In the worst case, Ofgem are presented with the prospect of GDNs arguing for a strong incentive while inflating plans and subsequently under spending. Similarly, implementing a weaker incentive could see GDNs spending as planned and recovering unnecessary investment through the RAV. Either way, the onus is to work from unbiased forecasts and we believe this is most likely with weaker incentives.

121. If Ofgem do strengthen the capex incentives, it might consider an appropriate cap to protect for unforeseen, unavoidable overspend which at a certain point triggers a review of forward looking allowances. In the interests of symmetry, we accept this philosophy should also apply to significant under spends, similar to the arrangements put in place in the recent TPCR determination.

Question 4: Are our proposals for the treatment of offtake reform related costs and mains replacement costs under the IQI appropriate?

Offtake reform

122. Suggesting that offtake reform related capex costs should be subject to the incentive chosen by the GDN under the IQI process implies that Ofgem expect offtake reform capex forecasts to be provided on an ex ante basis, subject to the under or overspend incentive and no post event analysis. This is problematic. The implementation delay means that no signals in relation to either take-up volume or price will be available ahead of completion of the price review and consequently there are no clear signals on which to base an ex ante capex forecast. We therefore believe that this is incompatible with the capex incentive proposed under the IQI, with the combined effect to penalise additional investment made in response to price signals from the interruption auctions

123. Given the need to treat capex related to offtake reform separately, we continue to believe that some form of post event assessment is necessary but that this can be minimised by adjusting the single incentive target to cover the return and depreciation earned on capital spent in any one year, as per our third Consultation response. This will of course now have to reflect the return and depreciation element of associated capex, and not just the difference between actuals and allowed.

124. The objective of both DN interruption and NTS exit reform is to create an incentive for the DN to make optimal decisions between investing in assets and entering into contractual arrangements e.g. for interruption. For this it happen efficiently requires the incentives to provide a “level playing field” between the associated capex and opex.

125. It has been proposed that these incentives could be provided by a combination of an incentive scheme for the contractual costs and the use of IQI for investment costs. However, the strength of the relative incentives on a DN for capital versus operational expenditure will be affected by:

- variations in the strength of capex incentive depending on which of the capex allowances the DN chooses under the IQI scheme,
- how many years the incentive scheme has left to run. Clearly there will be a stronger incentive to avoid costs under the incentive scheme during the first year, when the incentive properties will be felt for five years, than in the final year of a scheme,
- the strength of incentive under the scheme will also depend on whether the DN thinks that it is likely to go beyond the incentivised range and hit a cap/collar.

126. Given this variability in the strength of incentives, there can be no confidence that the proposed combination of incentives will reward an efficient trade off between investment in assets and contracts for interruption. It is for this reason that we have proposed that additional assets associated with exit and/or interruption reform should be identified and treated separately.

The inclusion of repex within the IQI

127. Our understanding of the inclusion of mains replacement costs within an IQI is that Ofgem intend to set a single IQI matrix premised on total investment costs and apply the chosen incentive rate to both capex and repex. We do not support this approach, believing that the limited scope in practice for overlap between capex and repex and the clear rules and accounting policies that exist means that alignment of capex and repex incentives for ‘gaming’ reasons is unnecessary.

128. Furthermore, in contrast to capital expenditure where GDNs are exposed to both cost and workload uncertainties (which, as described above are both mandatory and unpredictable), the current replacement mechanism generally limits GDNs to price exposure only. As such, given the greater controllability and predictability, we believe that it is entirely appropriate to have a stronger incentive associated with repex than capex. The underlying principle associated with IQI, i.e. that the GDNs choose the level of allowance and associated incentive, seems also appropriate for repex however. To this end, we believe a separate IQI matrix should be established for capex versus repex.

Service unit costs

129. Ofgem’s proposals to include services in the mains incentive will remove any potential misallocation issues between capex, opex and the incentive in relation to mains replacement.

There are two potential options Ofgem could use for the inclusion of service costs within the replacement incentive: combining the mains and service unit costs or establishing separate unit cost targets for services. Given that the drivers of service replacement are not fully aligned with mains replacement drivers, we foresee particular issues with the former approach. The costs of service replacement will be influenced by:

- the number of services replaced without any mains, such as the significant volumes replaced following the discovery of a leak on the service pipe;
- the number of services per km of main, itself impacted significantly by the type of housing stock being supplied (eg. terraced versus large detached);
- the length of service pipes, largely affected by the location of the pipe (eg. urban, semi-urban, rural footpath, road, or opposite side);
- the pressure tier of the main being replaced. Typically there are far fewer services off medium pressure mains;
- whether bulk renewal of services has been undertaken in the past which will significantly impact on the proportion of services that can be transferred rather than replaced.

130. Trying to incorporate these drivers into a single set of hybrid unit costs would almost certainly lead to significant variances (in either direction) between actuals and forecasts, as well as reducing the transparency to real world benchmarks and hence managements ability to react to the incentive. We would therefore propose that the incentive matrices include discrete unit costs for service replacements, to ensure appropriate protection for consumers and companies.

Chapter Six: Methodology for considering financial issues

Question 1: Do you agree with our proposed plan of work to determine the cost of capital? Are there other key areas of analysis that we should be carrying out?

131. We are pleased that Ofgem, in their approach to determining the cost of capital, are seeking consistency with previous controls and agree that cost of capital can only be set in context of overall proposals. It is appropriate that any market evidence on the risk free rate and debt premium are refreshed, but the use of trailing averages as proposed will pose problems in the event of actual interest rates rising above the trailing average.

132. Interest rates have risen since the completion of TPCR, with current redemption yields on 2016 index linked gilts above 2%, while adjustment of yields on similar term conventional gilts for an inflation rate of 2% (as proposed by Smithers) implies a real rate of over 3%. This compares with the TPCR assumption of 2.5% which, therefore, no longer looks as though it

would provide the sort of margin appropriate for a five year (plus) period. Even accepting a higher inflation rate of nearer to 2.5%, the real yield on conventional 10 year gilts would be over 2.5%.

133. Exercising caution in the use of CAPM methods to assess the cost of equity is appropriate given the difficulty of finding persuasive evidence to support a particular equity beta figure. Therefore, we agree that placing more weight on the aggregate return method may be more appropriate and this would additionally provide a consistency of approach. Where beta analysis may be more useful is in establishing a comparative position between different network types.

134. We support Ofgem's proposals to carry out a comparative risk assessment between Transmission and Distribution. However, we believe that the scope of analysis identified by Ofgem may be too limited. Qualitative issues such as structural maturity, government policy and safety risks are likely to have a bearing on the risk differential but would not be captured by modelling volatility of returns or analysis of the regulatory framework. Therefore, in addition to the work proposed by Ofgem, it is important that a full assessment of the qualitative risks of each business is carried out prior to any modelling. Where appropriate, the identified risk differentials should be incorporated into the proposed modelling. Where this is not possible, these factors should be reflected in the cost of capital differential via alternative methods.

135. In their discussion on financeability, Ofgem note that the financeability review will be materially affected by a range of factors including decision on the timing of repex funding, non-operational capex funding and capex funding; to these we would add any timing impact on the funding of "quasi capex" as discussed in paragraph 20. We regard the depreciation profile applied to the RAV as a material factor is assessing the comparative risk of investment different types of network asset. The 45 year standard in gas distribution exposes investors to several additional regulatory and political cycles when compared to depreciation lives in other asset classes.

Question 2: Is the range of key ratios we have identified adequate for carrying out an assessment of financeability?

136. If Ofgem intend to ignore the actual debt financing structure when setting a cost of capital, the actual equity ownership structure should also be ignored (i.e. the fact that "none of the GDNs are stand alone listed companies" should be irrelevant). A market rate of dividend and costs for raising additional equity, if required, should be allowed to ensure consistency.

137. Therefore, providing that the above point is factored into any assessment of financeability, we believe that the range of indicators detailed below are, together, the appropriate ratios to use in conjunction with other elements of the price control that affect the risk profile of the business and the volatility of its cash flows:

- FFO interest cover;
- Adjusted FFO interest cover (or PMICR);
- FFO/Debt;
- Retained cash flow/ debt;
- Net (post-dividend) cash flow/capex; and
- Debt/RAV

138. This is based on the assumption that adjusted FFO interest cover ratios such as PMICR are used as detailed in our response to the question 3.

Question 3: Is our approach to the issues raised by adjusted interest cover ratios appropriate (see Appendix 10 for details)?

139. In a special report on post-maintenance interest coverage ratios for UK regulated utilities (Fitch Ratings – Know Your Risk, Feb 2007), Fitch highlighted the shortcomings of the traditional interest coverage ratios (i.e. EBITDA / Interest and FFO interest cover). Fitch state that these ratios do not take into account any capital expenditure which is required to maintain a company's operations and more specifically the economic value of the network. Similarly, Moody's identify Debt/RAV and PMICR as the two key ratios they use in their assessment of the credit quality of UK gas distribution networks. With the attitude of the credit rating agencies to PMICR important in determining their ratings, these rating are, in turn, critical to the cost of financing. PMICR cannot, therefore, be ignored.

140. As noted by Ofgem, the ratings agencies currently take, as a proxy for maintenance capex, the sum of regulatory depreciation and the proportion of repex expensed in setting the price control, currently 50%. We agree with Ofgem's analysis that after taking out depreciation and the 50% of repex that is expensed, that the PMICR reduces to a function of the cost of capital. However, this only demonstrates that the funding for interest payments needs to come from cost of capital allowances, which is to be expected. It would not be reasonable, as a general rule, to expect interest payments to be funded out of depreciation or amounts allowed for repex.

141. Although there is an argument to say that maintenance capex is more deferrable than opex (so in a time of financial stress, a company has the option to delay maintenance capex projects), the improved short term cash flow is likely to be at the expense of the value of the

business. Therefore, although a one-off, low PMICR may not be a cause for concern to a credit rating agency (assuming other financeability ratios remain strong), a consistently low PMICR should not be disregarded by Ofgem in its consideration of financeability.

142. Indeed, Fitch concluded in their report: "…it would be hard for an uncovenanted entity to retain an investment-grade rating if the PMICRs were forecast to be consistently below 1.2x, unless other credit metrics were particularly strong."

143. As Ofgem note for NGET, in structures where debt to RAV is consistent with a mid single A (A2) rating (max 60% for NGET), Fitch have allowed more latitude in the levels of PMICR, i.e. allowing a lower PMICR than might seem appropriate for the rating as long as other ratios are not also strained. For gas distribution networks, 55% debt to RAV is consistent with an A2/A rating.

144. We believe that, if the price control outcome shows that gearing can be sustained at a level of 55% or below, with no additional equity issuance required, then PMICR limits may be somewhat relaxed, although they should still be maintained at, at least, the level of investment grade and preferably at comfortable investment grade. At higher levels of gearing (even those consistent with the A-/BBB+ ratings that Ofgem are indicating) it is less certain that the rating agencies would ignore PMICR. If Ofgem assume a gearing level of above 55%, then PMICR should be considered in more detail.

145. We note that the method that the credit rating agencies use to calculate PMICRs could be regarded as conservative with respect to holders of nominal bonds, but not to holders of index linked issues. Therefore we support Ofgem's proposal to determine whether an assumed and realistic proportion of index-linked financing would sufficiently alleviate a poor PMICR. Three points should be noted in relation to index-linked financing when making assumptions in modelling:

- Index linked financing is, in practice, more expensive than conventional financing and an appropriate adjustment to the cost of debt would be required.
- Index linked debt will result in increased refinancing requirements when accreted bonds mature. As Moody's note, this requires strong liquidity which will increase in cost as credit ratings deteriorate.
- As credit ratings deteriorate, index linked financing will become increasingly more difficult to obtain. For an A2 or A3 rating, it might be reasonable to assume that 40 to 50% of a gas distribution network's debt could be index linked. As ratings decline to BBB+/Baa1 and below, a reasonable proportion might be 25% of total debt or lower.

146. In the event that assuming an appropriate proportion of index linked debt does not alleviate the situation, we believe that an adjustment to the cost of debt allowance, would be the appropriate method of ensuring that the GDNs are able to finance their activities.

Appendix 1: PCM Worked Example

Activity opex	100
Discount Rate	6.25%
Staff Costs / Opex	80%
Pension Costs / Staff Costs	20%
Implied Pensionable Payroll	64
Implied Pension Rate	25%

	2007/8	**2008/9**	**2009/10**	**2010/11**	**2011/12**
Allowed Opex	100	100	100	100	100
Allowed Pensions	16	16	16	16	16

Cash Based PCM - Outsource would save 15% of costs

	2007/8	2008/9	2009/10	2010/11	2011/12
Shareholder NPV					
Opex Saving					
Revenue	100	100	100	100	100
Opex	-85	-85	-85	-85	-85
Cash Flow	15	15	15	15	15
PCM					
Allowed Pensions	16	16	16	16	16
Actual Pensions	0	0	0	0	0
Difference	-16	-16	-16	-16	-16
Cumulative PCM adjustment	-16	-33	-51	-70	-91
Cash Flows	15	15	15	15	15
Terminal Value					-91
Total	15	15	15	15	-76
NPV	-£4.18				
Customer NPV					
Cash Flows	0	0	0	0	0
Terminal Value of Opex Saving	0	0	0	0	240
PCM adjustment					91
Total	0	0	0	0	331
NPV	£244.18				

Payroll x Rate PCM - Outsource saving 15% of costs

	2007/8	2008/9	2009/10	2010/11	2011/12
Shareholder NPV					
Opex Saving					
Revenue	100	100	100	100	100
Opex	-85	-85	-85	-85	-85
Cash Flow	15	15	15	15	15

<u>PCM</u>					
Allowed Pensions	0	0	0	0	0
Actual Pensions	0	0	0	0	0
Difference	0	0	0	0	0
Cumulative PCM adjustment	0	0	0	0	0
Cash Flows	15	15	15	15	15
Terminal Value					0
Total	15	15	15	15	15
NPV	£63				
Customer NPV					
Cash Flows	0	0	0	0	0
Terminal Value of Opex Saving	0	0	0	0	240
PCM adjustment					0
Total	0	0	0	0	240
NPV	£177				