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28 April 2006

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Dear Bob,

Transmission Price Control Review – Third consultation April 2006

Thank you for the opportunity to comment on the third stage of your consultation on the Transmission Price Control for 2007- 2012.

Given below are the views expressed on behalf of the various companies of Centrica plc involved in the use of the Gas and Electricity Transmission networks, but excluding Centrica Storage Ltd.

In our previous response, we set out a number of high level principles and objectives, which we believe, should form the basis of the Price Control Review. Although for the sake of brevity these are not re-stated here, we continue to believe that these should be evident in the background of our comments on this review.

In the sections that follow I have, as far as possible, structured the response to address each of the questions posed in the "views invited" section of each chapter. These are included in italic at the beginning of each section. I hope that this is useful in evaluating the response and assimilating the comments to the relevant chapters.

Chapter 1 - Introduction

Although Ofgem has raised no specific questions in relation to this chapter, we would like to raise our concern that the Capex bids in table 1.1 have changed – in some cases very significantly – as compared with those set out in the Ofgem summary letter of 1 February 2006. There is still no information as to the major elements or drivers behind these forecasts, which remain substantially higher than current Capex levels, nor as to significant

items which have been added or (as the case may be) taken away from the forecast in the period since the beginning of February.

Given this limited information, it is difficult to provide a meaningful response to the consultation on issues, which relate to the Capex forecast. We would, once again, emphasise the need to achieve a major improvement in transparency on this key point, at the earliest possible opportunity.

Irrespective of the overall level of Capex allowances likely to be set for each year, it will be important for Ofgem to provide for the addition of an X factor to those Capex allowances to reflect the likely year on year efficiencies that could be expected to be made.

Chapter 2 - Form & Structure of Price Control

Question 2.1: Do you think the standard RPI-X framework needs to be refined or augmented in its application to the Transmission licences?

We remain broadly satisfied that the RPI-X framework for incentive regulation has been successful. Subject to the refinements set out in our response to the remaining questions in this chapter on the development of revenue drivers, we see a role for the continued application of RPI-X.

Question 2.2: Do you think that rolling incentive mechanisms are the most appropriate way to deliver a consistent strength of incentives over time, and do you think they are applicable to Transmission licences?

It is clearly important to avoid the risk of "incentive erosion" in the latter part of a price control period. We agree with the Ofgem position as set out in paragraph 2.14 of the Third Consultation Document, i.e. that the rolling incentive concept is as applicable to transmission as to distribution. Unless the more detailed analysis to be carried out in the remainder of the TPCR uncovers any material reasons to the contrary, we would hope and expect that a rolling incentive mechanism will be incorporated into the next period of Transmission Price Control.

Question 2.3: Given the large bids made by some licensees for asset replacement expenditure, how do you think the regulatory regime should look? Do you think that an "information quality incentive mechanism" is the best way to improve our information on efficient costs, by rewarding licensees more if they accept more challenging cost targets?

It goes without saying that licensees will have better information about their capital expenditure plans than any third party, including the regulator. In principle, we agree that an information quality incentive mechanism may help to address the risk of capex forecasts leading to a "gold plated" system, but there are still significant issues around the detailed design of such a mechanism. In particular, we are concerned that an open-ended opportunity to revise these forecasts once the mechanism has been designed (see paragraph 2.20 of the Consultation Document) may create scope for licensees to "game" the system.

In particular, it is important to consider whether the expectation of an uplift on returns likely to flow from such a mechanism, as a consequence of the introduction of such a mechanism following the DPCR capex submissions, did not itself create a perverse incentive to submit excessive initial bids.

We therefore consider that licensees should develop a forecast capital expenditure range, which Ofgem considers robust before the rolling incentive mechanism is finalised. If a forecast revision is allowed at that point, we consider that the revised forecast should not normally be allowed to lie outside the pre-established range, unless there are exceptional reasons for this, which Ofgem believes to be justified.

Question 2.4: Are additional measures needed to promote innovation? What is the scope for innovation by transmission licensees to benefit consumers?

We agree with the thrust of paragraphs 2.27 & 2.28 of the consultation document, to the effect that transmission licensees ought generally to be motivated to innovate, provided that the incentive regulation framework is appropriate. Nevertheless, we consider that there may be specific areas of significance, in R&D terms, where the current framework may not create the right commercial incentives.

A good example of this point is gas quality; the recent DTI consultation of 30 December 2005 highlighted the significant cost of potential remedial measures to address the changing diversity of gases seeking entry to the NTS. It is not clear to us that NGG NTS currently has a strong commercial incentive to fund sufficient research in this field.

Question 2.5: Should the current form and scope of System Operator (SO) incentive scheme be adopted in the next price control period?

There is a strong feeling within the industry that, especially for electricity, the recent history of the SO incentive scheme has been less than satisfactory. For a number of years, NGET appeared to be able to out-perform its targets significantly on a regular basis and yet NGET now seems to consider that the external portion of the 2006/7 incentive is much too tight.

Our view is that NGET's SO incentive scheme has, in the past, been over-generous. More generally, we consider that the structure of the scheme has failed to keep pace with the volatility in wholesale energy prices, such that the SO has been subject to windfall gains (or losses) as a result of unexpected shifts in the wholesale market. We therefore consider that the external portion of the incentive should be (partly) indexed in some way to movements in wholesale prices. This would be a kind of "revenue driver", improving the quality of the incentive and reducing the risk of further major discontinuities in the effective operation of the scheme.

Question 2.6: To what extent should incentives applying to Transmission Owner (TO) costs and SO internal costs be equalised? Should these costs (e.g. staff costs and IT spend) form part of the TO price control?

We agree with paragraph 2.37 of the consultation document, to the effect that any artificial incentives to shift costs across the notional boundaries between TO and internal SO incentive schemes should be minimised and, where possible, eliminated.

One simple way of achieving this outcome would be to equalise the incentives in the different categories of costs. If there are good reasons to retain differential incentives then a better definition of categorisation of costs including apportionment of shared costs and services would be required. However, the latter is a more intrusive and imprecise way of dealing with the problem identified.

Chapter 3 - Electricity Incentives

Question 3.1: Do you agree with our conclusion that the use of locational revenue drivers is the most appropriate way to set allowances for the electricity transmission licensees in the context of significant uncertainty over the future demand (and location of that demand) for network capacity?

We support the use of locational revenue drivers in setting allowances for the electricity transmission licensees. The advantage of being able to respond to unexpected events is significant, particularly given the requirement in the last price control to reopen the price controls to accommodate the volume of applications from renewable generators in Scotland. Additionally, we fully support the view that once set the revenue drivers should be left unchanged for the duration of the price control.

However, we believe there is still a case for some forecast of demand for new capacity as a supplement to actual demand. As discussions around the requirement for new capacity have shown, there is often some uncertainty surrounding applications against actual new generation delivered. The uncertainty is driven in part by the planning regime.

There is an argument for using a hybrid of the two methods of locational revenue drivers outlined in the consultation paper. Investment on the network is driven largely by the arrival of new demand and generation. However, there are also areas of constraint on the network, for example at the boundary of the SPTL and NGET networks, which also need to be considered. A methodology that allows for investment in these areas must also be considered.

Question 3.2: What factors should we bear in mind in drawing the boundary between fixed baseline revenue allowances and variable revenue allowances to be set through the revenue drivers?

In order that boundaries are defined between baseline allowances and variable allowances it is essential that current system capabilities are clearly defined. This must be transparent to industry in order that confidence in investment decisions can be maintained.

Consideration should also be given to the treatment of investment that has been approved or effectively funded from prior/current Price Controls but has not yet been undertaken.

Question 3.3: Should we seek to true-up the allowances generated by revenue drivers at the end of a 5-year price control period? What factors should we take into account?

We are unsure why a mechanism to 'true-up' allowances generated by revenue drivers is required if a transmission licensee only begins to receive revenue on an asset after it has been delivered. If the mechanism is to provide an allowed revenue on capacity that has not been constructed we would welcome explanation of how this aligns with the SO incentive scheme.

Question 3.4: When should we supplement the revenue drivers with other mechanisms to top-up revenue allowances in exceptional circumstances where major investment is needed? How might these other mechanisms work?

If the revenue drivers work effectively there should be no reason to have any corrective mechanism. However, the existing regulatory precedent for reopening price controls in truly exceptional circumstances, as long as it is applied in a genuinely symmetrical manner, should maintain the very strong focus on incentive regulation with a back stop where required.

Question 3.5: Do you agree that, in the current market context, it is important to explore options to change transmission access arrangements? Do you agree with the process we have set out to progress this work?

Centrica have been active participants in the ARODG and remain committed to achieving development of an appropriate regime for transmission access. We agree that there are reasons to examine the current mechanism for obtaining transmission access rights. The level of applications for connection in Scotland and Northern England, primarily driven by the Government's targets for renewable generation, have created a significant demand for access rights. However, it is important that any future arrangements take account of the whole of GB and do not just consider the most pressing issues. Additionally, it is important that the right changes are made, rather than making changes for change sake. We are particularly concerned that any changes do not drive cost into the energy market through increased, and potentially uncontrollable, constraint costs.

Chapter 4- Gas Entry Incentives

Question 4.1 Do you agree with our plans to change the nature of NGG NTS's licence obligations to release entry capacity? What particular measures are needed to ensure that the regime is transparent, and ensure against capacity being held back unnecessarily?

In this approach Ofgem are proposing a fundamental change by moving away from baselines and placing a licence obligation on NGG NTS to release all available capacity. Whilst we support the objective of ensuring that the maximum amount of capacity is released and therefore maximising the potential for gas flows, we have concerns about the workability of such an approach. This structure would afford a high degree of discretion to the Transporter. To ensure that capacity is released appropriately, NGG NTS must be

required to develop a “transparent” capacity release methodology and to publish a network model where this can be demonstrated. This model must be open and transparent to all players and there must be an obligation upon the Transporter to ensure that industry players are familiar with the model and mechanisms adopted. We recognise that this approach is intended to circumvent inflexibility of the current nodal model and encourage the transfer of capacity across different points. It is precisely in this area of “transferability” where a clear understanding of the methodology is essential. Ofgem’s preliminary view of this approach suggests that the total capacity that the system is currently capable of providing exceeds the existing baselines in the GT licence. If this were to be the case, then it would be an identifiable benefit of the approach.

This approach would address the anticipated increase in variability in the pattern of deliveries of gas to the NTS over the PCR period.

It is not immediately clear what other real problems are with the current mechanisms, which were introduced relatively recently in the last price control. The major argument is that capacity transfer has been stifled across entry points. This presumably could have led to unnecessary investment at some entry points and under valued capacity at others, where the baseline is well in excess of demand. However there appears to be no hard evidence suggesting what the difference may have been to recent NTS entry investment had capacity been allowed to transfer between nodes, as has been proposed in a recent Modification, or if capacity had been sold on a zonal rather than nodal basis.

From recent discussions it seems apparent that the revisions were being made to anticipate the requirement for additional new entry points in the next few years.

It would be helpful to see some analysis of how this approach would have affected the pattern of investment carried out in the current PCR period and addressed the concerns expressed.

We also have some concern that the existing process for Long Term Allocation process, that has been developed by the industry, may need to be redesigned.

The consultation on UCAs last year demonstrated that the confidence which Users have in this forward allocation process can be undermined by uncertainty. How will confidence in the long-term process be maintained with this further significant change? Currently Users will have committed to capacity for 3 to 18 years out taking prices based on current baselines and the expectation that 20% of that baseline would be held back and offered in the short-term auctions. Will the 20% retention for new entrants to the market be retained? If this is not the case, how will capacity be made available for “new-entrants” which was the justification for 20% being held back?

Exact terms for buy-back of entry capacity may not be known at the time of the allocation, therefore this will impact upon Users ability to commit in the long-term in this process.

We also note the paradox that Entry is moving away from having established baselines yet Exit is introducing them.

The “transparency” of the capacity release methodology is critical to the process and the confidence Users will have in committing to a predictable and stable product. To this end, we believe that there is merit in considering process for governance. There is a case for incorporating the methodology within the UNC rather than the licence in line with recent governance proposals.

It is not clear whether Shippers will be able to trade capacity across nodes within zones or whether NGG NTS be able to offer to buy back capacity at one node in order to sell it at another node. If so, how will it be incentivised to do this rather than revert to selling incremental capacity? It does suggest a requirement for some form of substitution obligation similar to that which has been proposed within the Exit regime.

We would note that Baselines give visibility to the market of minimum capacities that National Grid are required to provide on an ongoing basis. Where this has not been the case (ie National Grid’s LNG Storage business) we have seen reductions in capacities without consultation causing costs to be imposed upon the market whilst allowing NG to avoid maintenance and operational expenditure.

Question 4.2 Do you agree with our plans to refine how the revenue drivers in cases where NGG NTS provides extra entry capacity, as requested by network users?

It appears that it is proposed to change the revenue drivers for the provision of incremental capacity such that the drivers should vary by location with a trigger level at which the driver would be activated and a revenue allowance for long-run capacity sold over and above the trigger level. The revenue allowance for NGG NTS would be based on a deemed cost of providing additional capacity, fixed at the standard (yet to be determined) cost of capital for five years. This is intended to incentivise NGG NTS to beat the deemed cost and for customers to see benefits of any efficiency savings after 5 years.

This is intended to simplify the current complex set of calculation of the various types of capacity revenue (baseline, obligated incremental etc). However each entry point will appear to have its own trigger levels and revenue allowances which may be replacing one complexity with another.
It is not yet clear how the trigger levels would be calculated. Figures are published in the appendices of the paper but there is no corresponding methodology to explain how these have been determined. We believe that there is a potential to introduce perverse incentives in the way capacity is transferred across entry points. There appears to be no justification for believing NGG NTS will be encouraged to build incremental capacity when it has to better a return calculated using a standard cost of capital rather than an enhanced cost of capital.

Question 4.3 Do you agree that changes are needed to the arrangements for buying back capacity rights, in particular ensure a different sharing of risk between shippers, NG NTS and consumers in respect of capacity which is dependent on large investment projects?

Currently reserve prices are set on the basis of the cost of incremental capacity 5 years ago. We generally support Ofgem's belief that they need to change more frequently to be cost-reflective. This issue is being addressed at the Gas Transmission Charging Methodology Forum (GTCMF). However, we have concerns that this itself may introduce greater volatility in prices. This aspect of volatility can be addressed by ensuring that the methodology upon which cost reflective charges are based, is visible, transparent and understood. Again there is a case to be made for the governance of this methodology to be incorporated within the UNC rather than the licence in line with recent governance proposals.

With regard to frequency of price changes, we recognise that there needs to be something of a compromise. The practice established within the licences for annual revisions as standard should be the norm. The exceptions should provide for correction of revenue flows that are outside expectation and of sufficient materiality.

Ofgem have identified problems particularly where incremental capacity is delivered late. We recognise the concern that the current Cap methodology would be breached leaving NGG NTS with no further incentive to manage buy-back and pushing significant costs onto shippers, and hence consumers, if costs are smeared.
It appears that for significant incremental capacity provision, the buy-back arrangements would be agreed directly between NGG NTS and Users along the following lines:-

- Costs may vary depending on how much control NGG and/or shippers have over the delay
- NGG NTS may be able to buy-back at specified rates for new incremental capacity
- Rates may vary depending on where in the project cycle the buy-back occurs
- Shippers could agree to vary the standard buy-back process and delivery dates
- Default rates will be set by Ofgem for use where NGG NTS and a shipper cannot agree. These may be set to zero where a delay is caused by say problems in the planning approval process
- Costs and revenues (of incremental capacity) to be treated as excluded income for the purposes of the price control to ensure other shippers (and end consumers) are unaffected by an buy-back on incremental capacity

We have concerns about this move further towards the confines of bi-lateral agreements rather than open and transparent arrangements applied consistently across parties.

It is assumed that buy-back for non incremental capacity remains as current. If so, how will incremental capacity be distinguished from non-incremental where investment is carried out at existing entry points? As an alternative it may be appropriate to introduce greater complexity in this area, to differentiate between delays and cost increases outside the control of NG and those within and hence between those costs which more legitimately can be shared with the market and those which should be borne by NG shareholders.

<u>SO Incentives</u>

The design and application of incentives upon the System Operator is of paramount importance to the success of the Price Control. We note that a separate consultation is to be issued for the external incentive schemes for the SO to address the form, duration and scope for the arrangements to apply from April 2007

The current SO Incentive schemes are generally appropriate and should continue until such time as more detail is available for future arrangements. However, the proposals contained within this paper will require some quite different structures of incentives in order to extract the most effective operation of the network under such arrangements. We can see some merit in having specific incentives designed for specific activities, which may have different duration from other more stable areas of operation.

The interaction of incentives across the TO and SO functions is also an important area, The balance between the two must ensure that the appropriate party is rewarded for high performance and these incentives do not “leak” between the boundaries of operation, or worse, reward both parties for the same action.

Chapter 5 - Gas Off-take Incentives

Transitional Period

5.1 Is our proposed approach for the transitional period appropriate?
The continuation of interim NG NTS incentives (5.8) does seem appropriate. It is not possible to judge whether any of the arrangements from the enduring regime could be brought forward until greater detail of these is available.
Adoption of the basis of pre-specified revenue drivers for entire PCR (5.10) is an aspiration rather than passing through of estimates of financing & depreciation.
We note that baselines (Nodal) are to be established for April 2007 to September 2010 (5.11) but again comment that the methodology for setting the baselines is unclear.
We also note that no Baseline is proposed for Flexibility or Interruptible capacity (5.12) in the Transition period.

It is proposed that arrangements for Constrained LNG would continue in current form (5.16), we agree this is appropriate.

We note that it is not proposed to continue Buyback incentive in the interim period (5.17), again this seems appropriate.

Enduring Arrangements

5.2 Do you agree with the assessment, set out in this document, of the high level options in the Second Consultation?
5.3 Is the high level option proposed appropriate?
5.4 Do you agree with our thoughts on baselines, revenue drivers and payment flows given an emphasis on user commitments?
5.5 Are the proposals for a gas offtake buyback incentive appropriate?

Our current understanding of the proposed way forward is that based upon Option Ex2 of the original proposals but with some refinement (5.27). This would provide for a Nodal Product (5.25) and Nodal Baselines being set (5.26).
As expressed above, we do have concerns about the methodology that would be employed in order to allocate these baselines. In common with our comments on Entry, the methodology applied for these areas must be open, transparent and understandable. This is particularly relevant with regard to substitution of capacity across Nodes
We are supportive of the concept of NG NTS having a Substitution Obligation where they would only be rewarded for investment where opportunities for substitution have been exhausted (5.28), but again the key to the success of this arrangement will be in the design of the methodology and incentives.

Although we recognise the practicality of NG NTS having to apply to adjust baselines, this is again an area where there must be a complete understanding of the proposal, justification and implications of such adjustments. This can only be achieved by some form of modelling openly accessible by the wider industry.

We note the inclusion of both Flat & Flexibility products as an Expanding Flexibility product (App 12 1.17). We further note the comment that this approach requires robust "conversion factors" in order to translate any "unused" Flat capacity to a Flexibility product (App 12 1.71). This is also included within "work in progress" by the EOWG and will be key in the design and acceptability of the regime.

Interruptible Product

It is apparent from the paper that the long-term interruptible product will be available only by obtaining firm capacity and entering into a buy-back arrangement. We believe that this will be unlikely to meet needs of many existing interruptible customers! This itself may lead to signals for investment in the system which are essentially unnecessary to convey the volumes of gas required at off peak times. The only other service would be the availability of a Use it or lose it (UIOLI) service on day ahead. Again this is unlikely to satisfy the requirements of existing customers, as it does not provide any degree of certainty.

Method of Sale
We note that all Users would be offered the same product/service (5.31 & 5.33) and there would be no grounds for differential treatment of connectees. It is difficult to envisage a single regime that would adequately cater for the diverse needs of the range of connected parties.

User commitment would be required over fixed number of years to guarantee incremental capacity. Although the period of commitment has not yet been bottomed out, NG propose 3-4 years, Ofgem recognise this would incur costs upon Users. Users have made a counter proposal for 1-2 years and this is being resolved through the work of EOWG. We welcome the recognition that the Party making commitment may not be "User" (App 12 1.79).

We also welcome the view that the preferred option is for a Prevailing Rights model (App 12 1.78) where a specific action would be required from a User, or their customer, where some adjustment (upward or downward) was required.

We note that Pay as Bid processes would remain as a feature of Medium/Short term allocation within constrained period (App 12 1.83). This is welcomed as a continuation of a tried and well practised process for the industry.

Setting of Baselines
We support the adoption of Baselines at Nodal level. We concur that these should reflect Practical Maximum Physical Capability. This mirrors approach applied for Entry
Table A12.1.1 indicates redistribution of existing baselines across all (Firm & Interruptible) but the methodology applied to do so is not apparent.
We assume that the baselines for DN Offtakes are driven by the 1:20 obligation but we understand that these differ from those contained within the offtake statements. There is no detail for how these Transitional values have been derived.
The Transmission Connected Customers (TCC) Offtakes appear to be based upon existing Firm baselines but the Transition values appear to "re-distribute" the existing firm capacity across all (Firm and Interruptible) TCC offtake points.
The proposals indicate that Exit nodes will have established baseline in contrast to Entry where proposal is for greater discretion in setting system capability by NG. As stated in that Chapter (4), this is inconsistent!

Payment Flows (5.4.7 & A 12 1.118)
We note that Gas Distribution Networks are to have a central role in the payments process implemented in parallel with the Enduring regime. Under these arrangements GDN Shippers would make payment for Transmission Exit Capacity (TEC) and Distribution Exit Capacity (DEC) and DEC overruns to GDNs, then GDNs would pay NTS for TEC & TEC overruns.
What is unclear from the proposal is whether the basis of charging would be to pass through charges (Σ SOQ) or to "optimised" (actual NTS to DN Offtake). This could have a significant impact to the rates for the charges applied.

Chapter 6 - Expenditure Analysis : Capex

Question 6.1: Do you have any comments on our approach to assessing historic and forecast Capex? Are there any other factors we should take into account?

We do not currently feel in a position to give detailed feedback in respect of this question, as we do not believe that there is sufficient transparency around the detail of how the forecasts have been derived. To give one prominent example, the latest NGG Capex forecast of just over £1.1 bn compares with a range of £1.4-2.0 bn set out in the Ofgem summary letter of 1 February 2006. It is not at all clear (a) what explains the significant reduction in this forecast over the last few months, and (b) whether the previous significant range in NGG's Capex forecasts remains relevant or not.

Our primary comment at this stage is that far more transparency is required as soon as possible, in order to facilitate meaningful responses to consultation on the part of network users such as ourselves.

Question 6.2: Should some degree of alignment be adopted for capitalisation of forecast costs across transmission licensees, or should, especially in the case of the Scottish Licensees, the approach be consistent with DPCR?

We believe that in this area it will be key to understand the likely distributional effects of such a standardisation policy. What will be the effects on different groups of customers, what are the associated costs and benefits and what will be the effect at a network level?

Standardisation might be expected to assist in accurate benchmarking of companies, but we do not consider there is sufficient information to properly judge the likely outcome.

In addition, we are not entirely clear as to what is being proposed and which policy would be taken as standard. If this is to be pursued, we would welcome further analysis and presentation of the likely outcomes in order to provide a more considered response. As an initial view, it seems likely that the favoured option would be to standardise on NG's approach, subject to transparency and consistency of what is included in which "pot".

Question 6.3: Should some adjustment be made to network flexibility margins, particularly for the NTS 5% planning flow margin.

In our view, the scale of the flow margin is such that we believe it would be reasonable to allow this to continue in view of uncertainties in forecasting future demand. In investment planning terms, the incremental cost of including this flow margin (e.g. by allowing for slightly increased pipe diameters or somewhat larger compressor capacities) will often be small in relation to the industry "value at risk" in the event that the 1-in-20 peak day capacity is not in fact available under severe winter conditions.

We are not, at this stage, convinced that the user commitment regime operating at entry is, as yet, a sufficiently precise instrument to obviate the case for a modest precautionary planning margin around the 1-in-20 standard.

In addition to the above, we believe that it may be worth linking this area to that of the Capex incentives, encouraging the Transporter to take on additional risk.

Question 6.4:In carrying out cost-benefit analysis to assess the efficient level of transmission capacity to accommodate wind generation, what new factors need to be taken into account?

The level of transmission capacity to accommodate generation is largely driven by the SQSS. We agree with the contention that it would not be appropriate to apply the same capacity scaling factor on wind generation as applies to conventional generation. However, we also note that currently a lower capacity scaling factor is used for wind

generation in the existing SQSS (around 60%). It is questionable whether or not a lower capacity scaling factor can be used.

We note that two institutions have been undertaking work on the impact of wind generation on the SQSS. It would preferable if these reports were available for Ofgem's consideration within the TPCR timescales. However, as this may not be possible we agree that derogations from the SQSS may be appropriate.

Question 6.5: What would be the most appropriate approach to restoring the incentives for relevant parties to reach the most cost-effective connection design? How should the TPCR allowance take into account various solutions?

The examination of the charging methodologies to allow customer choice in local transmission assets is a necessary step. However, as the design of the local transmission assets is driven by the SQSS it is also appropriate to consider whether this could be amended to allow customer choice in connection design.

This is particularly the case for any connections that use under-sea cables as the challenges faced in the offshore environment are substantially different to those onshore. We note that Ofgem will be taking forward a technical workstream under the Offshore Transmission Expert Group. It is our view that these offshore issues could be best considered here albeit there may be a requirement for a reopening of the price control to accommodate any decisions taken here.

Chapter 7 - Expenditure Analysis : Opex

Question 7.1 Do you have any comments on our approach to assessing historic and forecast opex? Are there any other factors which should be taken into account?

As with the similar question under Chapter 6 Capex, we do not currently feel in a position to give detailed feedback in respect of this question, as we do not believe that there is sufficient transparency around the detail of how the forecasts have been derived. if we wish to comment

Question 7.2: How should non operational capex be treated with regard to 1) the assessment of efficiency of associated activities such as IT; 2) the treatment of historically incurred overspends; and 3) the approach to future remuneration?

In this area, the consultation document itself does not contain enough detail or quantitative analysis to enable a robust judgement on the best treatment. One reason for conducting such analysis at an early stage is to judge whether the costs are of sufficient magnitude to justify individual treatment for different sectors. An initial view would be that 40 or 45 years is a long period over which to manage IT costs, however, depending on the scale of such investment, the effect may prove to be minimal overall.

Question 7.3: Do you have any comments on our comparison of unit cost trends? Are there reasons why transmission licensees should have performed differently to DNOs?

From figure 7.2 and table 7.1 of the consultation document, the sharpest difference in unit cost trends appears to be between the DNOs and NGET, on the one hand, and the Scottish transmission companies, on the other. There might be an argument that transmission companies, being less labour intensive businesses, have not been able to reduce unit costs as much as the DNOs. However, this does not begin to explain why the unit cost reductions made by the Scottish TOs have been so limited, as compared with NGET.

In principle we support the use of benchmarking techniques of similar or related industries and functions to directly inform the setting of X factors.

Question 7.4: How should we treat non-controllable costs? Should we take the same approach to network rates as in DPCR?

This would seem sensible subject to an obligation on the licensees to take all reasonable steps to minimise such costs, and report on actions taken.

Chapter 8 - Financial Issues

Our response on this chapter is necessarily somewhat high level at this stage, to highlight the key issues as we see them. In short, we consider that the real post-tax cost of capital of 4.8% (equivalent to around 7% post-tax nominal) adopted in the final EDPCR now appears to be significantly too high. We expect to return to these matters in more detail at a later stage in the review.

Question 8.1: Are there other issues that the cost of capital study should address?

Our initial thoughts would be that the risk free rate implied by the final EDPCR paper of around 2.7% (real) now seems very high and that it should be more closely aligned to the current and expected future returns on index linked gilts. In 2004, Ofgem may have been motivated by a degree of caution as regards the sustainability of low bond yields, but (if so) then such caution is surely no longer warranted. Considering current yields on 5 or 20 year index linked gilts would probably imply a real risk free rate in the range 1.5-1.7%, at least 100 basis points below the EDPCR view.

Question 8.2: How should we approach our assumptions for the cost of debt? Should we use medium term historic averages?

We believe that more stringent assumptions could be safely used for the cost of debt. There are essentially two possible approaches, which lead to numerically somewhat different but directionally similar conclusions:

- Adding an assumed commercial debt premium (previously seen by Ofgem as 1.4%) to the risk-free rate; and/or
- Directly observing the cost of corporate debt for the licensees and similarly rated major companies.

As a benchmark, the pre-tax cost of debt used in the final EDPCR decision (as of end 2004) was around 4.1% real (just over 6% nominal).

The first approach outlined above would suggest a pre-tax cost of debt of the order 3% real (5% nominal).

Taking the second approach, the 20 and 5 year swaps (which approximate to LIBOR) are currently yielding 4.7-5.0% (nominal) and we understand that a National Grid 30-year bond is currently trading at around 60 basis points over swaps. This would appear to indicate a real pre-tax cost of debt in the range 3.25-3.5%.

Even using the higher end of the higher range, this suggests that the EDCPR cost of debt figure is now well over 50 basis points too high.

Question 8.3: How should we reflect the risk profiles of licensees in estimating the cost of capital?

We believe that the risk profile of transmission licensees is significantly lower than the risk faced by other quoted companies in the market and hence that Ofgem should apply an equity β of significantly less than 1.

We have assessed possible areas of risk for quoted companies, highlighting those in which we believe that the risk faced by transmission companies is less than that faced by the market as a whole, as described below.

Areas of relatively low risk

- Gas and electricity demands are relatively stable through the economic cycle
- The demand for transmission capacity, as opposed to the commodity, is even more stable
- Little or no direct competition (natural monopoly); the regulatory regime cannot replicate the impact of real world competitors
- Robust demand growth provides continued future income growth, providing appropriate revenue drivers are applied.
- Regulated Asset Base provides high level of long term revenue certainty and thus good earnings quality
- Any income shortfall against price control limits in one year (e.g. due to weather variations) can be recouped in the following year, providing further income security.
- Price control performance is typically characterised by out-performance, providing increased profit opportunities
- Long “product” lives, with a relatively slow rate of technological change (i.e. relatively low risks around product spec, technical innovation and R&D)
- Very little exposure to exchange rate risk
- Growing use of “user commitment” mechanisms significantly reduces investment risk and offsets uncertainty as to future demand from network users
- Similarly, user contributions towards connection costs also reduce capex risk. Recent proposals may reduce this risk to near zero.

- If/when Ofgem introduces them, electricity DNO-style pensions pass-through arrangements will significantly reduce company risk
- A stable and well understood regulatory regime

Areas of relatively high risk

- Significant and rising levels of capital expenditure, with associated risks around financing costs (e.g. interest rates). Revenue drivers may be expected to assist in this area.
- Regulatory risk of new proposals, again, mitigated by special provisions in the Price Control/Licence.

Ofgem has in the past alluded to the well-known problems of "parameter stability" (i.e. the difficulty of observing robust and stable measures of β for regulated network businesses. However, this does not in logic support a conclusion that the licensees face average market risk. On the basis of the argument set out above, we believe the only reasonable conclusion to be that the assumed equity β should be significantly less than 1.

Question 8.4: Should we still use conservative gearing assumptions and assume target ratings comfortably within investment grade when setting the cost of capital and assessing financial stability? What financial indicators should we use?

Given the scale of the Capex programmes to be financed within the next review period, we do understand the need to have regard to financial indicators and financing capacity. We do not have a detailed view on the preferred choice of financial indicators but we do consider that the question of gearing needs to be handled with some care, given (for example) the significantly split current ratings of National Grid by the major agencies and the fact that one needs a "synthetic" target rating for the regulated entity, as distinct from the corporate entity with its other business interests. The financing arrangements behind some of the recent GDN acquisitions also provide a possible counterweight to unduly conservative gearing assumptions.

Question 8.5: Which option or combination of options should be used to address the loss of income from pre-vesting assets becoming fully depreciated?

Tilted depreciation should only be used if there is confidence that this is not merely pushing a greater problem into the future. Moreover, we share the concerns raised by Ofgem about using the repex approach, which is in any event a form of fully accelerated depreciation. Whilst the do nothing approach may be inconsistent with the approach in DPCR4 it may be the preferred way forward. For example, if there are little or no financing impacts flowing from the depreciation cliff face. However, it is not possible to suggest an appropriate way forward with out any more information from Ofgem on the likely short and long term effects of the different options for these particular licensees.

Question 8.6: Do the existing ring-fencing conditions provide adequate protection for consumers?

We believe that this is appropriate.

Question 8.7: Is benchmarking the level of total employment costs the best means to incentivised the licensees to control their pension costs?

This seems reasonable and would appear, at least in part, to address our previous concerns about pass-through type arrangements for pension costs significantly weakening incentives in this area and reduce the scope for perverse cost substitution.

We fully support the last sentence of paragraph 8.32, to the effect that NGG customers should not bear any costs associated with supply business pensioners and deferred pensioners, since these arrangements were a matter of public record at the time of demerger and thus a risk to be borne by shareholders in BG plc or (subsequently) National Grid.

8.8: Should there be any ex-post adjustments to the licensees revenues allowances for tax payments?

We do not have an issue, in principle, with continuing the ex ante approach to tax adopted in the EDPCR. The key is to maintain incentives towards an efficient structure whilst ensuring that customers eventually share the benefit of any greater efficiency.

In summary

I hope that these comments are useful and informative at this stage of the Price Control Review. You will be aware that we are actively engaged, both directly and by means of participation within the Gas Forum group, in supporting the work of this PCR. We would welcome the opportunity to discuss these issues with you directly, perhaps within the next stage of the process.

Please contact me if you require any further information.

Yours sincerely,

Mike Young
Commercial Manager