Centrica Energy

Millstream East
Maidenhead Road
Windsor
Berkshire
SL4 5GD

Tel. (01753) 431242
Fax (01753) 431150
Our Ref.
Your Ref.

2 February 2006

Robert Hull
Director, Transmission
Office of Gas & Electricity Markets
9 Millbank
London
SW1P 3GE

Dear Robert

Transmission Price Control Review – Second consultation December 2005

Thank you for the opportunity to comment on the second stage of your consultation on the Transmission Price Control for 2007. I would like to apologise again for the delay in submitting this response.

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.

At high level we believe that the Price Control should be aimed at achieving a number of objectives:-

- It should be reflective of the mainly low risk operation of this regulated business but rewarding, where appropriate, the higher risk activities associated with the effective operation and development of the networks. We believe that the rate of return on the asset should be commensurate with this exposure to risk.
- It should afford consistency of approach in order to facilitate a stable regime of pricing which is the manner in which the revenue will be recovered.
- It should strive to minimise administrative costs within the industry and avoid introduction of complexity where possible.
- It should involve an appropriate incentive structure which is related not only to the safe, efficient and economic operation and development of the Transmission networks but also recognises that a number of the entities connected to these networks are also regulated businesses and subject to their own incentive arrangements. Each must facilitate the interaction between the numerous parties to ensure that any scope for perverse incentives are minimised.
- It should promote all the relevant objectives detailed within the parties licence obligations

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.

4. Cost Assessment

♦ *How should cost assessment take account of potential changes to SQSS – and in the absence of certainty as to when and how such changes might be implemented, what should Ofgem assume in estimating efficient future costs?*

We recognise the potential for a change to the Security & Quality of Supply Standard (SQSS) within the duration of the price control. It would appear that the only realistic way to approach the future costs is to base these on current actual use rather than potential use. Although if the changes to the SQSS are made prior to April 2007 it may be that appropriate adjustments can be made prior to implementation.

♦ *How should Ofgem assess the need for additional capital expenditure allowances to provide flexibility in the availability of network capacity in advance of firm demands for capacity by network users? What, if any, reasons might there be for consumers placing a higher (or lower) value on such network flexibility over the next price control period as compared to the current (or past) price control periods?*

The proposal to identify, and levy a charge, specifically for flexibility is a relatively recent concept. Historically, it has been difficult to identify the costs associated with the provision of flexibility. Within any network there will exist an amount of flexibility inherent with the asset itself. We are not aware of any investment in the system which has been solely for the provision of incremental flexibility. The degree of flexibility will vary widely with the conditions that apply at any particular time. For these reasons it is difficult to quantify the amount of flexibility available and it therefore follows that it will be difficult to identify the requirement for and the cost of providing any incremental flexibility. We do not believe that there is any particular rationale for a higher, or lower, value being placed upon flexibility from one price control period to another. However, there is a risk that the desire to identify available flexibility in some forward period may introduce an entirely artificial perception of scarcity of the product. Our view, which we believe, is held widely across the industry, is that it is relatively rare that the requirement for system flexibility will exceed the availability. It is estimated that this may arise on less than 1% of days. Based upon the above we do not believe there is a need for additional capital expenditure allowances to provide flexibility. It is more appropriate, in our view, to adopt arrangements for management of available flexibility in the short term on the infrequent occasions where this arises.

♦ *How should allowances be set for investment to support efficient system operation, and how, in the case of electricity transmission, should interactions between NGET and SPTL and SHETL be managed in this context?*

There are a series of interactions between the various parties, which should be accommodated within the price control and incentives. Generally, the role of the TO, in terms of investment in the system, will have some impact upon efficient system operation and therefore the costs of the SO. Where these are part of the same organisation it could be assumed that this would lead to overall efficiency. However, where the TO and SO functions are under separate ownership there is a potential for one party to avoid costs and therefore increase the costs faced by the other. We believe that one way to remove or

at least reduce this potential conflict would be to expose all TOs to some part of the SO costs through their incentives.

5. Form and structure of price controls

♦ *How can Ofgem minimise the adverse consequences of price control reopeners if they prove to be unavoidable – even in the context of more sophisticated mechanisms for adjusting revenues automatically within the price control period?*

We share Ofgem's concern on the adverse consequences of re-openers within the Price Control. This can lead to uncertainty and unpredictable variations in Transportation charges. Whilst we recognise that it may be impossible to provide for every eventuality within the structure of the control, it is preferable to exclude the potential for significant change. It would seem that any such unforeseen events could be accommodated by an "Income Adjusting Event" process, provided that there are clear parameters established for the criteria to determine IAEs. This approach allows an adjustment of a significant variance but would subject the issue to scrutiny of the merits of the individual case. We also note that a high level of transparency and information availability is necessary to allow users to raise IAEs, where appropriate, as well as transmission licensees.

♦ *How should the information on NGET's and National Grid NTS's performance under their current SO incentives, as set out in the report compiled by National Grid, be interpreted by Ofgem in developing an appropriate regulatory regime for these activities from 1 April 2007 onwards?*

The setting of appropriate incentives is key to influencing the manner in which the Transporter will respond under given circumstances. In setting the regime for the future price control period, an assessment of the effect of incentives in the prior period must be taken into account. This is not solely in respect of the level of performance achieved, but more importantly the way in which the operation or behaviour of the Transporter has been influenced by the incentives in place during that prior period and whether this was as intended or expected.

♦ *How might the differences between transmission and distribution, discussed above, influence the design of information quality and rolling incentives as part of the TPCR?*

♦ *How might any additional reporting arrangements (or financial incentives) in respect of environmental impacts be framed, and are such arrangements an appropriate element of the overall regulatory regime given the wider legal framework within which the transmission licensees operate?*

We would welcome greater transparency in reporting the performance of the Transporter against their incentives. This enables an early awareness of the ability of the Transporter to achieve performance targets and the effect of any changes in performance or behaviour. This approach supports the adoption of rolling incentives which in themselves will be less susceptible to variations in their impact at different times through the price control period.

We support the addition of reporting requirements and incentives in respect of environmental impacts. These should allow the Transporter to account for investment that is not necessarily least cost, but has least environmental impact. The justification from a move from a potential internalisation of environmental benefits is the wider political framework in which the industry operates. It is arguably in the consumers' best interests to allow development to accommodate development of renewable generation on the network.

A key issue is to ensure the transmission incentives align with those on distribution companies to encourage the connection of renewable generation on their networks. It is essential that this development is not hindered by the transmission incentives.

6. Price control design options – framework

♦ *Whether respondents agree that Ofgem's focus on 'user commitment' options is appropriate, or whether they consider that there are other traditional price control options (or de-regulated revenue options) that might better meet Ofgem's objectives for the TPCR, particularly in the context of the Authority's statutory and other legal duties?*

♦ *What is the appropriate allocation of investment risk between network users (both generally and at specific locations), transmission companies, and consumers, during the different phases of investment development, e.g. planning and design, construction, and operation?*

Whilst there is an attraction to adopting a "user commitment" approach to investment, as this is an essential ingredient, we would caution against placing too high a reliance upon this single facet.

Any user commitment is likely to be relatively short term, particularly in relation to the life of transmission network assets. Therefore, we are of the view that it is essential to maintain a balance between the known short term needs of specific network users and the longer term requirements of the network overall. This inevitably involves a degree of risk upon the various parties and it is key to ensure that rewards are proportionate to the risk entailed. The Transporter, particularly of a transmission network, has the role of forecasting the future requirements of the customers and other connected networks, informed by specific user requirements but also combined with its own assessment of system use and load growth. This involves an element of risk in making efficient and economic investment. The reward, in terms of the return from such investments, should rightly reflect the degree of risk to which it is exposed. An approach relying solely upon user commitment is essentially low (or no) risk for the Transporter and should only be rewarded with a commensurate low rate of return.

♦ *Whether it is appropriate to seek to separate, both formally and operationally, the issue of how charging and reserve prices are set at gas entry from the issue of how incremental revenues are determined under the price control?*

Whilst we support the concepts of cost reflectivity and transparency, we have concerns about the effect of large swings in the UCAs and hence reserve prices applied. We can see that it is impossible to avoid such pricing variations altogether, the experience to date demonstrates that there is a significant flaw in the process which may be data-related but is more likely to be within the methodology or the tools applied within that methodology. The fact that such different values can result in the analysis carried out from year to year suggest that there is a problem in the way that Transcost applies the information available. The sharp changes in UCAs which have been indicated for System Entry Capacity severely undermine the ability of a User to commit in the longer term. In order to make such commitments, and to provide the required signals for the Transporter to invest efficiently in the system, there must be a high degree of certainty and stability in the products being offered to network users. This stability must endure beyond the duration of a individual price control and be more aligned to the life of the asset. We believe that consistency of approach would provide stability with the correct application of the tools available.

7. Incentives options - gas

Revenue drivers for entry and offtake

(a) Should the revenue driver be nodal, zonal/locational or global? What are the advantages and disadvantages of these different options – and to what extent do these advantages and disadvantages differ between entry and offtake? If a zonal approach is preferred, then how might zones be defined?

These issues are yet to be finalised within the discussions at the Enduring Offtake Working Group (EOWG). There are a number of related matters, which would also have a bearing on the preference. Apart from the question of Nodal/Zonal definitions, there is little visibility of Baseline quantities or any interchangeability (e.g. between Entry Points) at present. Until there is an opportunity to assess the options with all known factors, it is difficult to form a view of which set of alternatives would best suit the requirements of Users and consumers. With regard to Entry arrangements, there has been no detailed consideration of interchangeability of capacity between entry points. We understand that there is very limited scope for this and with this in mind it would seem to advocate the continued application of a nodal (System Entry Point) product.

(b) What are the key cost drivers of incremental capacity – and how might these vary between entry and offtake? How should these be quantified?

There is a close relationship between capacity at Entry and at Offtake. The provision of any additional pipeline capacity on the system will have some effect upon the available capacity at Entry and Offtake. In addition it will increase the availability of linepack or flexibility. This relationship needs to be accommodated within the price control and within the incentive arrangements. [It would be inequitable to allow a benefit to be realised on all three from a single investment without factoring this interaction into the equation.

(c) Should revenue drivers be fixed for the price control period or should they be adjusted during the price control period?

The majority of system Users seek stability of prices. Therefore one way in which to achieve this stability is to adopt consistent revenue drivers. As long as the revenue drivers are appropriately set in a manner as to be cost reflective, where possible they should endure throughout the price control period. This would provide the requisite stability. However, where there are untoward variances it may be necessary to adopt some mechanism to address exceptions. Provided that there is a volume-related element included within the drivers, this would seem to accommodate the majority of situations. IAE's would be available for major unforeseen events. The quality of forecast itself is incentivised if reopening of the revenue drivers is not available. Where additional adjustment is sought greater transparency is needed of all costs in order that adjustments can be demonstrably seen to be furthering true costs.

Entry capacity baselines

(d) Should the baseline be a measure of capacity and if so, should it reflect the level of existing capacity or the level of anticipated capacity?

Following the practice adopted for the Entry Capacity regime, the baseline has been set by an assessment of the existing capabilities of the assets currently in place. This facilitates a reasonable return reflecting the essentially low risk involved in the operation of an existing asset. Having set this baseline it is then possible to reward the Transporter appropriately

where it has accepted a higher degree of risk associated with the provision of incremental capacity. To set a baseline upon the anticipated level of capacity would confuse the two drivers.

There is then a question on how the capability of the system is assessed. Given that the system cannot support maximum physical capability of all parts of the network at the same time, there is a need to make some allowance for this diversity. In the case of System Entry Capacity, the baseline capacity has been set at 90% of peak (maximum physical) capability. Although this is a somewhat arbitrary number, it does appear to reasonably approximate the level of diversity.

(e) For revenue restriction purposes should the baseline be set 'flat' for the five years of the price control period or should it incorporate growth (or decline)?

For reasons of stability it is preferable for the baselines to be set for the duration of the price control. This does not necessarily mean that they are flat through the period. It would appear to be a benefit if the baselines reflected known growth, i.e. incremental capacity identified in prior price controls. This would provide a clear distinction between existing capacity, that was signalled (and rewarded) within previous control periods, and that which is identified as incremental within the current control period.

(f) Should the baseline be set on an entry point specific, zonal or network wide basis or should no ex ante baseline be defined? What are the advantages and disadvantages of the different options?

Currently baselines for Entry capacity are set at System Entry Point (ASEP) level. Without some established process for interchangeability or exchange rates between Entry Points it is difficult to assess the merits of a zonal approach.

For the reasons above, we believe that it would be inappropriate not to set a baseline capacity in advance for the period of the price control.

Approaches to offtake reform

(g) Do you believe that Ofgem's proposals for a long term user commitment model are appropriate?

As mentioned above, the reliance solely upon User commitment model is flawed, as the duration of this commitment is unlikely to reflect the life and hence the potential return on the investment. It is therefore necessary in our view to require the Transporter to adopt a central role to assess the long-term needs of its present and future customers, underpinned by a robust planning process. This can then be further informed and enhanced by an appropriate demonstration of User commitment through the mechanism adopted for the shorter term.

(h) Are there any alternative models, including those which could be characterised as variants of the status quo, that would meet the defined objectives?

The models that have been presented within the consultation are closely related to those which were incompletely considered last year. The timescale upon which these have been made available, again with an incomplete appraisal of the supporting information which is essential to any analysis, has left little time for consideration of any alternative. The work of EOWG is continuing and will shortly consider alternatives to the options contained within the document. We consider that it would be imprudent to concentrate only on the options

presented in the consultation document before stakeholders have been given any opportunity to consider workable alternatives.

Offtake product definition and baselines

(i) Which of the options described for product definition and baseline determination do you believe is most appropriate?

(j) Are there any alternative models that would meet the defined objectives? Eg a nodal model without the substitution incentive or a "no baseline" option?

(k) Should the baselines be fixed for the five year period, or increase over time?

(l) What method of determination of baseline levels (as discussed in Appendix 7) is most appropriate for the determination of the level of offtake baselines?

It is precisely these issues which are currently being considered by EOWG. Until these options have been considered, complete with indicative baselines, pricing information and substitution, it is impossible to make a judgment as to which would be in the best interest of the industry in general.

Offtake access arrangements and incentives

(m) What threshold should trigger the release of incremental offtake capacity eg a percentage of the deemed cost of providing the incremental capacity, a fixed number of years of commitment or another approach?

(n) How should National Grid NTS be incentivised to release incremental capacity as soon as possible, and should the limit on release be set as a fixed period, for example, three years, or linked to a fixed interval once the relevant planning consents have been obtained?

These questions are also dependent upon the structure of the adopted regime. We recognise that the application of incentives is key to the successful operation of the regime, but cannot make an assessment of the relevant incentive arrangements until more of the issues relating to structure have been resolved.

Transitional offtake incentives and revenue drivers

(o) To what extent should incentives and revenue drivers for National Grid NTS in relation to capacity for the transitional period represent a continuation of the current "interim" NTS incentives, including the 15 day interruption incentive on the NTS?

(p) To what extent should incentives and revenue drivers for National Grid NTS in relation to capacity for the transitional period be consistent with the enduring NTS incentives that will be determined?

The requirement to apply Transitional Arrangements is a consequence of the issue not being resolved within the timetable of Distribution Network Sales. The Transitional Arrangements are essentially a roll forward of the existing regime for capacity booking and holding. Therefore it would be appropriate to extend this approach and roll forward the existing incentive arrangements as a default. However, should proposals emerge that are consistent with the enduring regime, when this is finalised, it would be sensible to introduce the relevant elements of this at an earlier stage.

Buy back incentives for entry and offtake

(q) Would it be appropriate to treat buy backs from operational constraints differently compared with buy-backs resulting from delayed investment for incremental capacity? If

so, should there be two different buy-back mechanisms and what would the advantages and disadvantages be? How could we distinguish between the two types of constraints?
(r) Should the existing buy back incentive be refined to ensure an appropriate allocation and management of risk or should a different type of buy back incentive be considered, and if so, what form might this take?
(s) Should delay to incremental investment due to connecting pipelines be included in the buy back incentive?
Essentially, an operational constraint is within the control of the SO activity within the Transmission system and delays in investment are within the control of the TO activity. In order to ensure that each is incentivised appropriately, we believe that it is necessary to treat each type of buy back separately. We appreciate that this introduces a level of complexity, but this is relatively minor. It should be straightforward to identify a buy back related to delay in investment, including that within connecting pipelines, as this will be specific to capacity that does not exist rather than that which does exist but is not available at that time.

(t) How should risks be allocated between shippers, National Grid Gas and consumers?
(u) Would it be desirable for the regulatory regime to enable more flexible contractual arrangements between shippers and National Grid Gas (for example in relation to construction scope)? How might this achieved? What would the advantages and disadvantages be, especially how might this impact on consumers?
We firmly believe that National Grid Gas should be exposed to a greater element of the risk, proportionate with their ability to influence and deliver the objective. Also that shippers/consumers should face lower risk where they have little opportunity to influence outcomes. Generally this risk must be related to the Transporters ability to gain reward from their actions in terms of their rate of return and performance against incentives. It is not appropriate to place all risks upon Shippers and their customers, suppliers and consumers, as these risks are often outside of their range of influence.
Particularly where a long-term commitment is required, there would be an advantage in the Transporter being able to contract direct with the party with a long-term interest. Where it is common for a supply contract to be of 1 year duration (or less), however, it adds an undue level of complexity to require provision for a shipper to undertake a long-term (8+ year) commitment and synchronise transfer of this with the supply contract.

Interactions between entry and offtake options
(v) What are the main interactions between entry and offtake, and how does this affect the approach to baselines, revenue drivers and buy-back mechanisms?
(w) Should the same approach to baselines and the revenue driver be adopted for entry and offtake? What would be the advantages and disadvantages of doing so?
(x) Should there be one buy-back incentive covering both entry and offtake?
As mentioned above, we believe that there is a close correlation between Entry and Offtake Capacity. The provision and/or curtailment of capacity at either Entry or Offtake will affect the other. In certain circumstances it could be seen that a buy back of Offtake capacity could resolve a problem at Entry if the incentives were to be applied in that way. Therefore, it would appear sensible to establish a common and complimentary incentive framework across Entry and Offtake in order that there is no potential to skew the solution to capacity constraint issues away from the location of the cause.

8. Incentive options – electricity

♦ *Has Ofgem focused on the appropriate issues to be addressed in the light of operation of the current price controls?*

♦ *Is it appropriate to develop more sophisticated revenue drivers under a 'status quo' option – and if so, what designs of revenue driver might be considered to be most appropriate and worthy of further detailed analysis and quantification?*

Centrica agrees with Ofgem's analysis of the limitations of the existing price controls for the transmission owners. It is preferable to have a more flexible approach to accommodate the changing demands on the network. Any revenue drivers developed should account for changes in the volume of connected demand as well as generation. It is also notable that the increase in generation is being driven to a large extent by connections of distributed generation, in part due to incentives on DNOs. Any changes to the current price control mechanisms should not inhibit the development of active DNO management or new connections to the DNO networks. As such, it may be appropriate to consider drivers in terms of MW flows rather than connected generation

♦ *What are the advantages and disadvantages of user commitment models, as characterised above, in the context of electricity transmission?*

We reiterate the points made above in relation to user commitment models, specifically that they should not be used as the sole driver for network investment.

Arguably the current regime for access to the electricity transmission network is a form of user commitment model. In order to obtain a connection to the transmission network a new user must sign an agreement with the system operator for connection and transmission entry capacity, implicit in which there is a commitment to pay transmission use of system charges on an ongoing basis. The user underwrites any works required in order to facilitate the connection of the new user, during construction of the assets. This provision extends to wider system reinforcements. The transmission companies are therefore getting a clear signal to invest from generators and demand and the risk to the transmission companies is minimal. The chance of stranded assets only arises at the end of the construction phase should the new connectee fail to use the network and pay its share of transmission use of system charges. It is difficult to see how the proposals in the document would reduce this risk or improve on the signals received by the transmission companies.

Centrica also notes that it is difficult to establish how a user commitment model could successfully work with the current electricity transmission charging model. The concept of negative charging zones and their associated payments to generators sits poorly with the principle of payment for capacity rights to use the network.

♦ *What do respondents consider to be the most appropriate answers to the detailed design questions highlighted above for user commitment models?*

Are there any further questions that should be added to the list?

Whilst we recognise the need for information to be provided to the transmission companies in order that they can make efficient investment decisions, this should not be done at the expense of transparency and simplicity in the market arrangements.

How should the baseline capacities be set?

We do not agree with Ofgem's assessment of what constitutes baseline capacity. In our view baseline capacity is more accurately reflected as being equal to the aggregate of the

Connection Entry Capacity (CEC). This is the level to which connections are built and it is incumbent on the generator to determine whether or not it wishes to pay TEC for this level of capacity. The point here is that the level of CEC reflects the investment in the network to date. The transmission companies have been making a return on this investment and it is inappropriate to reward them for provision of incremental capacity which is already available to network users.

What is the mechanism whereby users (current and prospective) commit their profile of demand for network capacity – and are there any alternative mechanisms which deliver similar effects?

In our view, users already have a commitment to indicate their profile annually through their purchase of TEC, and in the shorter term by STTEC. We do not believe the proposals, for annual and monthly windows, will improve the information available to NGET on future network requirements. Furthermore, in areas where capacity is constrained it is hard to see why a generator would wish to purchase anything less than TEC equivalent to their peak output as the risk of failing to obtain TEC when they required it would be significant.

What would the network user be committing too?

We agree with Ofgem's view that the user would be committing to pay use of system charges. We are not sure what benefits of offering the choice of a fixed or variable charge would be. This suggestion appears to increase the complexity of the charging arrangements with little benefit to either the transmission companies or to the users.

What would trigger the release of incremental capacity? When would incremental capacity be released?

Theoretically, the current arrangements would be sufficient to trigger the release of incremental capacity. Any connection contract that is signed by a user with NGET should trigger additional investment as the contracts are for the lifetime of the generator, which is for longer than 10 years, and provide a commitment to pay use of system charges. The difficulty arises as the trigger for incremental capacity may come some time before it can physically be released, especially if the planning process causes delays.

How would scare capacity be allocated in the short term?

We are concerned with the proposals to ration capacity, particularly for those users with existing rights. Constraining existing generators will have a considerable impact on their commercial operation and potentially on the security of supply of the network. Further, this approach will drive up costs associated with network access which will inevitably be passed through to consumers.

What would happen if allocated capacity (either under the baseline, or as a consequence of incremental capacity being released) could not be delivered physically at any point?

If baseline capacity is not delivered then buybacks are necessary. This is also the case for incremental capacity but there should also be some mechanism whereby there is a revenue restriction within the price control.

An additional question that should be added to the list is how is a zone defined? Arguably if this approach is taken the zones must be defined in the price control in order that that they do not change over the duration of the price control. This will give stability in signals received by the users and the transmission companies.

♦ *What is the appropriate means of managing a process to develop user commitment model options given the interactions with the revenue restriction, Connection and Use of System Code (CUSC), charging methodologies and other codes and documents? What role should Ofgem adopt in this process? What role should NGET take, given its role of GB System Operator and its obligations in respect of charging methodologies?*
If Ofgem is committed to bringing forward a user commitment model then, due to the highly compartmentalised nature of the regulatory framework, it is incumbent on Ofgem to run the process. If this is taken forward under the CUSC framework, any discussions will be stymied by the requirement not to discuss changes required to the charging methodologies and other documentation.

9. Financial issues

♦ *whether the level and trend of key financial indicators consistent with a credit rating that is comfortably within investment grade provides the most appropriate approach to assessing the ability of the licensee to finance its regulated business;*
♦ *the financing of the asset replacement cycle;*
♦ *whether an ex-ante approach to setting tax allowances (with an ex-post adjustment for gearing and interest expense where relevant) is still appropriate;*
♦ *gearing issues, including:*
♦ *whether a common assumed level of gearing should be adopted for transmission companies, or*
♦ *whether company-specific gearing assumptions should be adopted, and*
♦ *what levels of gearing may be appropriate,*
♦ *the principles that should apply for assessing the past capital expenditure in excess of allowances;*
♦ *the cessation of pre-vesting regulatory depreciation for electricity transmission companies;*
♦ *pensions issues, including:*
♦ *the calculation of charges in respect of pensions and deferred pensions attributable to GDNs;*
♦ *the valuation and funding of pension schemes under new pensions regulation arrangements;*
♦ *the allocation between price-controlled and non-price-controlled activities;*
♦ *the options in relation to the treatment of over/under funding;*
♦ *the treatment of early retirement deficiency costs;*
♦ *a more detailed regulatory reporting requirement in accordance with regulatory reporting guidelines.*

We do not, as yet, have sufficient information to express a definitive view on many of these issues. Nevertheless, we do have some preliminary reactions to a number of the questions raised.

First of all, we are now clearly aware of the very significant increase in the transmission companies' capex projections for the forthcoming 2007-12 control period, as compared with the current one. This increase is particularly dramatic in electricity. We are also aware that this reflects, at least in part, the natural life cycle of transmission assets constructed in the 1960s and 1970s. It will nevertheless be critically important for Ofgem to assure itself, and the wider stakeholder community, that this is a necessary and efficient level of expenditure to fulfil the relevant transmission company obligations.

We wish to comment on a number of other financial issues, as follows:

- Given the capex projections above and the need for incentives to finance necessary expenditure efficiently and effectively, the question of gearing assumptions is perhaps even more important than usual.
- Ofgem should therefore have regard to credit rating issues, as suggested in the Consultation Document, as well as to balance sheet efficiency taking into account the forecast level of necessary capex.
- We continue to support the use of an imputed (efficient) level of gearing for the transmission businesses rather than actual gearing levels. This does not exclude the use of different gearing assumptions for different companies, but this would have to be justified by (for example) clearly identifiable differences in the level of non-diversifiable risk or (as mentioned below) the effective tax rates which they face.
- We do not object to the adoption of a post tax cost of capital approach, as has also recently been suggested for the GDPCR., It will, however, be necessary to assess the specific tax liabilities of each of the transmission businesses in order to ensure the most appropriate cost of capital is used, rather than assuming a standard 30% corporate rate.
- We are keen to avoid simple pass-through of pension costs, as occurred with the electricity distribution companies. Instead, we believe a full review of pension treatment would be appropriate.
- We support more detailed regulatory reporting arrangements in the interests of addressing information asymmetry and helping to ensure that Ofgem is as well placed as possible to judge the warranted level of efficient allowable revenues in future price control reviews.

I hope that these comments are useful and informative at this stage of the Price Control Review. 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