SP Transmission

Response to Ofgem Consultation Paper:

Transmission Price Control Review 2007 - 2012

Third Consultation

March 2006

Members of the ScottishPower group

New Alderston House Dove Wynd Strathclyde Business Park Bellshill ML4 3FF
Telephone (01698) 413000 Fax (01698) 413053

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1. Introduction

This response to Ofgem's Third Consultation on the Transmission Price Control Review is submitted by SP Transmission, which is the Transmission Owner (TO) for central and southern Scotland. This Price Control Review is reaching a critical stage and we expect initial proposals to be published in June 2006.

We agree that the key theme for this price review is investment to ensure network security and provide infrastructure to connect renewable generation to meet government targets. It must be noted that consumers' interests depend on the delivery of the government's energy policy objectives to facilitate renewable generation, minimise carbon emissions and ensure security of supply.

Our key messages are:

- To ensure continued financeability, baseline revenue should include all load and non-load related investment forecast by the TO
- Our depreciation "cliff edge" should be addressed using the standard approach developed for DNOs in DPCR4
- Incentives should be compatible with the different types of load related investment.
- Funds associated with load related investment must be provided in line with the investment rather than on connection completion
- Network incentives should be symmetric, entirely within the control of the TO and recognise the slow moving impact of transmission investment
- Given the uncertainty around load related investment requirements driven by the growth in renewable generation there should be a "true-up" mechanism at the end of the price control period
- Our cost of capital should reflect our increased risk exposure and at this time should fall into the range of 5% - 6% post-tax real.
- Our input costs are expected to rise above RPI
- We are concerned that Ofgem has allowed insufficient time to fully consider our future investment plans before publication of the initial proposals in June.

Price Review Process

The short period for responses to this consultation paper highlights the extremely tight timescales for this price review. At this key stage, we are concerned that Ofgem has

allowed insufficient time to thoroughly review and understand our future investment plans and then publish initial proposals by the end of June.

Full transparency of the review process is also very important and we strongly recommend that Ofgem's consultant's findings be disclosed to the TOs at an early stage, in the form of draft or finalised reports.

2. Form and Structure of the 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 licensees?

While we support the continued use of RPI-X, as it has proven incentive properties, we recognise that the basic framework needs to be refined.

In view of the considerable uncertainty surrounding the volume, location and timing of renewable generation, especially in Scotland, there will need to be supplementary component/s to the price control which will allow revenue to be adjusted, in an appropriate manner, to reflect actual developments. These component/s must ensure that funds associated with load related investment are provided in line with the investment rather than on connection completion.

It is well known that the basic fixed term RPI-X price control introduces an undesirable periodicity effect, as the incentive to out-perform the price control assumptions reduces through the price control period. Subject to being simple to understand and workable, we support the principle of refining the RPI-X framework in a way which offers the same incentive to outperform in each year of the price control period.

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 licensees?

We support the use of a rolling incentive mechanism for capital expenditure which would allow us to retain up to 60% of the present value of the cost savings.

The rolling capex incentive mechanism should ensure consistency of the strength of the incentive to make efficiency savings throughout the price control period.

However, we do not consider it sufficient to assess such an incentive mechanism simply in terms of the length of the lag in a basic rolling capital expenditure mechanism. This is because the strength of incentive for efficiency in capital expenditure resulting from a basic rolling mechanism depends on the depreciation rate, as well as the length of the rolling retention period.

It is more appropriate to assess the strength of an incentive for efficiency as the proportion of the present value of cost savings which are retained by the company, rather than simply the length of the period for which they are retained. More information on improved rolling capex mechanisms is provided in Appendix 1.

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 a " 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?

We support the introduction of an information quality incentive which is designed to improve the accuracy of the licensees' non-load related capital expenditure forecasts and allows companies to choose their preferred risk profile. However, for such a mechanism to work effectively companies must have the opportunity to re-forecast their capital expenditure requirements after the detailed mechanism and associated parameters are established. For future price control reviews, this should occur prior to the submission of our forecast business plan questionnaire.

The sliding scale mechanism, which was developed for DPCR4, can be improved, so as to provide an "information quality incentive mechanism" for non-load related capital expenditure for transmission. In particular, the incentive mechanism should be calibrated so as to avoid penalising a company that accurately forecasts its capital expenditure requirements. We also suggest that a more accurate mechanism can be established by mathematically solving the condition required for an optimal solution.[1] This would ensure the pay-off matrix is incentive compatible, without having to resort to a trial and error approach, which may introduce odd effects.

The concern we have with an information quality incentive mechanism is that it places too much emphasis on the consultant's review process and the subsequent consultant's benchmark. We have commented on this issue in our responses to DPCR4 and would stress that it is essential that there is full transparency of the consultant's reports.

[1] In mathematical terms, this is the solution of the differential equation for the first order condition that arises from imposing the incentive compatibility condition on the function that relates the company's profit to its forecast capital expenditure requirement, relative to the benchmark.

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

In our TPCR business plan submission, we identified a number of innovative projects that would, if successful, yield significant benefits for the transmission network and its stakeholders, ranging from asset integrity / monitoring systems to improve security of supply through to alternative designs for overhead lines providing less environmental (visual) impact to that of traditional structures.

Without adequate funding, we will be unable to resource Research & Development (R&D) activities. As a result, the network will continue to evolve using established technologies and techniques.

The increase in innovation following the introduction of the Innovation Funding Incentive (IFI) for the distribution licensees is showing to be giving a much needed lift to development activities across the sector. Within the DNOs the mechanism is providing both short-term benefits and is changing the approach to risk. Externally, there are benefits to R&D establishments - with additional funding, improved steer on projects and re-energisation of academic activities, essential in educating and inspiring the next generation of developments (i.e. its technology and electrical engineers). If a consistent mechanism were to be in place across both distribution and transmission networks, it is clear that synergies may be possible.

To this end, SPT would welcome an introduction of an IFI mechanism for use on the transmission networks.

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

As a general principle, it is important not to introduce incentives for incentives sake. Any incentives must be understandable with a real end-benefit to customers. The time duration should be set to achieve an appropriate balance between uncertainty and risk whilst ensuring sufficient time for observable outputs.

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 would support the move to equalise the treatment of TO and SO costs and to remove any perverse incentive to reclassify costs across the boundary between the SO and TO functions.

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 are generally supportive of symmetrical incentive arrangements subject to their compatibility with the different elements of load related investment.

If revenue drivers are to be introduced, then it is important that they are cost-reflective and as far as possible provide funding at the time investment occurs. The best approach to achieve cost-reflective drivers is to derive from as large a sample of costs as possible. We therefore recommend that appropriate, and potentially disaggregated, revenue drivers are derived from known costs obtained from projects for which we have contractual commitments from users.

Generation Related Investment

We are currently processing over 5GW of renewable generation related applications and expect to accept well over 2GW into our system from SHETL and transfer up to 3.1GW from our system into NGET by the end of this next price control period. Different incentives are appropriate for the different types of load related investment (boundary transfers, infrastructure (shared use and sole use) and connections) as outlined below.

Boundary transfer assets (H2 assets)
Reinforcements of the main transmission system are required to partially alleviate constraints associated with the B5 and B6 boundaries. The main driver for this investment is system security i.e. compliance with the GB Security and Quality of Supply Standard. We believe that a cost benefit analysis will support the economics of this investment and we are confident that such an analysis will demonstrate clear economic justification for these reinforcements.

If there is clear justification then the TO should be provided with a return for its investment during the construction phase and be incentivised to deliver timely and cost-efficient works by receiving full capital funding (i.e. including depreciation) on project completion. This type of incentive arrangement, based around the TIRG arrangements, would require preparation and agreement of a detailed plan and costs prior to the start of the reinforcement project/s.

Infrastructure - shared use assets (H1 shared use)
Recognising the strategic nature of investment necessary to provide infrastructure to meet government energy targets, we have proposed an approach based on ‘collector systems’ that extends the existing network towards geographic clusters of windfarms. These collector networks (i.e. shared used infrastructure assets) are

designed to accommodate connections in the overall most efficient way and also build in the ability to expand capacity to accommodate further connections if required without stranding the original assets. As with boundary transfer investment, we recommend that the TO should be provided with a return for its investment during the construction phase and be incentivised to deliver timely and cost-efficient works by receiving full capital funding (i.e. including depreciation) on project completion.

Infrastructure - sole use assets (H1 sole use)
The cost of connecting renewable generation can vary substantially reflecting the location and voltage of existing assets, connection voltage, circuit length, underground cable length and route topography. Due to the considerable diversity in the cost of this infrastructure, we require a baseline allowance that includes our investment forecasts and a revenue driver (which may need to be disaggregated to ensure cost reflectivity) that adjusts revenues in line with actual MW under construction in any given year. There would be "true-up" at the end of the price control period.

Connection assets (A1 "plug" assets)
These assets are funded through annual charges or capital contributions. If users elect to pay through annual charges then the TO must provide the initial funding for these assets. Although not funded through the price control, it is important that Ofgem takes due account of this investment, for both demand and generation connections, when assessing the financeability or our business.

Demand Related Investment

Demand related investment (connection and general infrastructure) as detailed in our business plan submission to Ofgem, should be included within baseline revenue.

We recommend that costs associated with any new demand connections that we were unaware of when we submitted our business plan but require investment during the price control period should be funded through a demand revenue driver with full "true-up" at the end of the price control period.

Contractual Commitments Prior to April 2007

We do not believe a user commitment model could be effectively implemented by 1 April 2007, since it will require changes to industry documents including the Grid Code, STC CUSC and charging statements, followed up by changes to contractual arrangements with users under the CUSC. However, by this date we will have already contracted to deliver a substantial amount of additional capacity to connect renewable generation. This transitional expenditure must be funded in the baseline rather than through revenue drivers.

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?

Boundary Between Fixed Baseline and Variable Revenue Allowances

Baseline revenue allowances should be provided where there is a reasonable degree of certainty over the cost and need for investment to ensure transmission companies maintain financeability. We require a baseline allowance that includes our investment forecasts with a revenue driver (which may need to be disaggregated to ensure cost reflectivity) that adjusts revenues in line with actual MW under construction in any given year.

Timing of Funds

It is very important that we have sufficient and timely funding for our load related investment. Lags in funding, such as funds that commence on connection completion, are not appropriate due to the adverse impact on the timing of cash flows and consequently on financeability.

Network Incentives

We note that Ofgem would like to extend reliability/performance measures with a clear preference for asymmetric incentives i.e. penalties only. We believe that any such incentives must be symmetric i.e. penalties and rewards. Furthermore, a 'penalty only' scheme may well distort decisions regarding discretionary expenditure, as any available expenditure would be diverted to areas where there is the opportunity to earn a reward. If such schemes are to be introduced then it is essential that such schemes are entirely within the control of the TO and have observable metrics.

The development of performance incentives should be consistent with customers' willingness to pay for improvements. It is also necessary to take into account the respective responsibilities of the GBSO and the Scottish TOs. In particular, the duration of interruptions to supply is largely outside the control of the Scottish TOs.

It is also our view that given the tight timescales we are working to, the extent and potential complexity of introducing load related revenue drivers and incentive schemes, together with the challenges in assessing companies' non-load related forecasts to ensure continued security of networks that this is an area of work that would be best considered for future workstreams rather than hastily introduced.

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

Our financeability as a stand-alone business is a fundamental issue for SP Transmission in this price review. It is therefore very important that any incentive arrangements, such as revenue drivers, provide sufficient funds in line with the timing of investment.

We require full "true-up" at the end of the control period. This allows for incentive effects during the price control while also ensuring that changes to scope and costs are accounted for.

4. Expenditure Analysis: Capital Expenditure

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?

Historic Capex

Ofgem intends to use variance analysis to examine the major factors influencing the differences between actual capex incurred and the projections made at the time of setting the last price controls. Since Ofgem did not allow our forecast requirements for the last price review it has been necessary to amend our initial plans. Hence we believe that it is more appropriate to analyse our actual capex against the overall allowance.

For non-load related capex we have managed our total spend across the 5-year period within 3% of the allowance provided by Ofgem. This reflects a 20% reduction compared with our original capex and given the scale of reduction, an assessment of actual capex against forecast projections will be meaningless as the actual projects delivered were reviewed in order to manage within the allowance.

The factors that influence load related and non-load related capex are significantly different. Load related capex is influenced by customer behaviour over which we have little or no control. Load related forecasts made at the time of a price review will inevitably change both in estimated profile of spend and value of capex due to new customer requirements. The historic period was characterised by an increase in load related spend due to both demand and generation connections. This spend was

necessary for licence compliance but could not be foreseen at the time of the last price control review.

Transmission capex tends to be characterised by large individual projects. Delays and modifications in scope caused by environmental and planning issues can have a significant impact on the capex spend profile. Our forecasts were based on valid assumptions at that time.

It is also relevant to note that a significant review of historic capex was undertaken to agree the two-year price control extension for 2005/06 and 2006/07. This should limit a requirement for further work on assessing projects undertaken during the historic period.

Forecast Capex

This price control review is characterised by a requirement for capital investment on a scale that is unprecedented in recent years. Significant investment in load related capex is required to support the connection of renewable energy in Scotland. Increased investment in non-load related capex is required simply to maintain existing performance and condition of an ageing asset base. The price control must provide sufficient funding for the capex increase which we are already contracted to deliver.

We agree that there is uncertainty in the volume, location and timing of renewable generation connections in Scotland. Given the uncertainty, we have modelled a realistic and conservative range of scenarios to arrive at a co-ordinated approach which is scaleable dependent on actual connections. We are confident that our forecast is realistic and recommend that baseline funding should be set using this forecast.

Non-load related investment is driven by our Asset Risk Management (ARM) policies, which are integral to our business. High-level asset management strategies ultimately lead to targeted investment to manage risk within our transmission asset base, taking into account age, condition and criticality of individual transmission assets.

We support Ofgem's aim to review our asset management systems and are confident that we can demonstrate our ability to effectively manage these highly critical assets. However, we are unclear as to how the assessment of our systems will impact on our non-load allowance. We also believe that Ofgem should place greater emphasis on the output from the ARM survey completed in 2002 and, in future reviews, the extent to which licensees have achieved compliance with BSI – PAS55. It is therefore essential that we continue to work with Ofgem and its consultants to enhance their understanding of our capital plans and of the consequence of any proposed reductions to our allowance.

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

Inevitably the proportion of support costs capitalised, whilst still complying with the applicable accounting standards, will vary between companies and as such a normalised allowance is a logical approach. The approach taken at DPCR in respect of support costs capitalised was an appropriate and pragmatic way to normalise costs.

In order to increase the transparency of regulation and to more intuitively understand the RAV, we believe there is a strong argument to, as closely as possibly, align RAV additions with fixed asset additions as required by the applicable accounting standards and reported within Statutory and Regulatory Accounts.

We believe that activities, whether capitalised or expensed should be fully cost reflective in order to provide appropriate economic signals and it should come as no surprise that in times of high capital investment, a significant proportion of support costs are capitalized. For historic investment going into the RAV, it should reflect the capital adjustments in place at that time.

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 main driver for transmission investment should be system security, i.e. there should be sufficient investment in transmission capacity to ensure that security is not compromised by the connection of new generation. However, there is merit in carrying out cost benefit analysis to assess the economics of major upgrade projects required to support new generation.

In our view the methodology developed by Sinclair Knight Mertz (SKM) is basically sound and could be used as part of the TPCR analysis. However we had significant concerns around the assumptions underlying the TIRG analysis and would make the following suggested improvements:

- Realistic assumptions must be used around key parameters such as existing generation background and cost of constrained energy.
- Information on actual constraint costs should be used wherever possible.
- Sensitivity analysis must be carried out on main assumptions.
- Only the incremental costs associated with an upgrade under consideration should be assessed (i.e. costs of doing nothing should be deducted).

In instances where it is concluded that upgrades are not economically justified then consideration should be given as to whether it is appropriate for generation to be

allowed to connect and then constrained off at particular times, as this will be the most economic means of accommodating the generation.

Where an upgrade is not economically justified and it is not possible for the licensee to comply with the SQSS, we would expect Ofgem to grant derogation/s. We would also expect Ofgem to support the GBSO / TO in responding to any challenges / determinations from customers requiring connections in such circumstances.

In addition to an economic assessment, we believe that the potential impact on incentives should be considered if an upgrade recommended by the TO is not allowed to proceed.

Finally, we also believe that Ofgem should also consider the impact of "plugs" connections and in particular the loss of locational messages on users that have resulted from the introduction of this policy.

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 the various solutions?

We have a licence requirement to develop our network in a coordinated and economic manner. This obligation is consistent with our approach to take a long-term view on the cost and design of connections and infrastructure. In effect, this results in optimal and cost-effective designs that comply with the SQSS.

5. Expenditure Analysis: Operating Expenditure

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

Historic operating expenditure is consistent with the level necessary to comply with legal and licence obligations, maintain safety and network integrity and ensure long-term sustainability. We believe we have reached a point where the scope for further cost reductions are extremely limited. Moving forward we expect significant upward cost pressures.

We believe that the scale of our operating costs are such that benchmarking comparisons across the three transmission companies and internationally are not appropriate. We have built our engineering opex forecast from the bottom up, based

on asset inspection, condition assessment and maintenance and repair activities and believe our forecast is the minimum required to satisfy our legal and licence obligations.

It is very important that Ofgem takes into account the fact that we face significant cost pressures going forward as our asset base grows in size and the overall age of our assets increases. There are also increasing cost pressures above RPI particularly in the supply of raw materials (e.g. metal prices), manufacturing and contracting activities. Our operating cost submission is based on limiting cost increases to RPI however this is a very challenging target particularly given that as a mature business there are limited further efficiencies available.

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?

The assessment of efficiency of associated activities such as IT

We support with the approach detailed within Para 7.12. Whilst SPT expects to undertake a significant investment in non-operational capital expenditure (IT) in the coming years we would urge that the extent of detailed data gathering required for such spend in *historical* periods reflects materiality and is defined in advance (e.g. RRP).

The treatment of historically incurred overspends

We support the approach detailed within Para 7.13 but would ask for a suitably pragmatic approach given that past allowances were not fully defined and the spend is relatively immaterial in SP Transmission's case.

The approach to future remuneration

We welcomed Ofgem's inclusion of non-operational capex in the RAV in the distribution review and this approach should also be repeated in this transmission review. Rather than the standard depreciation life, we strongly recommend that RAV asset lives for the non-operational capex should be 5 to 7 years as this capex relates predominantly to short life IT expenditure.

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 DNO's?

The Use of Benchmarking

We have commented in the past on the difficulty in undertaking comparative analysis in electricity transmission. The limited number of UK transmission companies with vastly differing characteristics requires significant normalisation to achieve any form of like-for-like comparison. Although the number of comparators can be increased by including international companies in benchmarking comparisons, the problems of effective normalisation are further increased due to, for example, different organisational structures, regulatory duties and accounting practices.

We have also commented that the most productive use of benchmarking comparison is on a selective basis, e.g. to identify specific areas where efficiency improvements can be made. If inter-company comparisons are to be used, such as the ROUE trends in Figure 7.2, they are only appropriate as a cross-check rather than as a method of deriving future operating costs.

Real Unit Operating Costs

We do not consider that there is any benefit in relating operating cost to GWh data as detailed in the RUOE graph in Figure 7.2, as there is no proven relationship between operating cost and units transmitted or distributed.

In general, great care should be taken in designing and interpreting graphs such as ROUE. For example, unlike ROUE where NGET's ratio at the end of the historic period is lower than the Scottish companies, operating cost comparisons derived on the basis of RAV, circuit kilometres, or substations would give the Scottish companies lower operating cost ratios than NGET.

We also disagree with the statement that the reduction in operating costs has been limited in our case. For instance we have delivered a 27% reduction to our controllable opex since 1994/95.

Our Engineering Opex Submission

As we have already noted, we face considerable cost pressures over the next control period. In terms of our business plan submission, we have built our engineering opex forecast from the bottom up, based on inspection, condition assessment and maintenance and repair activity and believe our forecast is the minimum required to satisfy our obligations. There will be an increase in costs due in the main to new tower and plant painting programmes necessary to safeguard the long term integrity and reliability of our assets.

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

Non-controllable costs should be treated as a cost pass through since by definition the TO cannot influence such costs. Network rates should continue to be treated as a non-controllable cost-pass through and be reviewed at the next rating valuation as per DPCR4.

6. Financial Issues

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

We welcome this study which appears to look beyond the components of the Capital Asset Pricing Model (CAPM). However, we believe that the following issues should also be considered:

- the increase in the required return resulting from the introduction of incentives and the exposure to revenue adjustment mechanisms and potential "buy-back" obligations under User Commitment;
- the evidence for a "value premium" and its application to regulated utilities;
- evidence from the dividend discount model using published dividend forecasts;
- the costs of issuing new debt and equity;
- the inverse relation between the equity risk premium and the risk free rate;
- the relation between higher gearing and the cost of equity;
- the evidence for higher co-moments (co-skewness and co-kurtosis) affecting required returns; and
- the implications of real option theory for investment under uncertainty.

We shall be making a full submission on the cost of capital in due course but would advocate that the range for returns is between 5% - 6% post-tax real at this time.

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

Clearly, we are aware that market conditions change continuously. However, the price control assumes the cost of debt, as a component of the weighted average cost of capital, is fixed for the duration of the forthcoming price control period. A consistent,

predictable and robust approach is therefore required when setting the cost of debt in advance of each price control period.

Our preferred approach is to calculate the cost of debt as the medium to long term average of the historic cost of debt for the sector, assuming the same credit rating as is consistent with the assumptions for gearing and other financial ratios.

This avoids the volatility of spot rates and the difficulty of forecasting interest rates and debt premia up to 2012. It also avoids the need to make further adjustments for the cost of embedded debt. Furthermore, this approach provides a predictable basis for future price controls and therefore helps to reduce regulatory risk.

Question 8.3: How should we reflect the risk profiles of licensees in estimating the cost of capital? Are risks below the market average?

We do not consider that there is sufficient evidence to justify using an equity beta of below unity for the Scottish TOs. In recent years, beta estimates for both National Grid and ScottishPower will have been significantly lowered by their US operations, as it is well known that rate of return regulation reduces observed systematic risk.

Also, in so far as the assumed gearing, which is used to calculate the WACC, is higher than the historic levels of gearing of the sectors or entities observed, then the estimated beta must first be de-levered to calculate the underlying asset beta and then re-levered to derive the equity beta consistent with the assumed level of gearing. We note that several regulators now estimate equity betas to be above unity, partly reflecting this gearing adjustment.

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?

There is no clear basis on which to determine precisely the level of gearing which minimises the weighted average cost of capital (WACC). In practice, it is likely that the WACC is broadly flat over a range of gearing. In particular, we do not see any justification for assuming a higher level of gearing for Scottish TOs than was assumed for DNOs in DPCR4. Moreover, excessive levels of gearing would effectively transfer risks, which would normally be borne by investors, to customers.

Ofgem should use financial ratios which are consistent with comfortable investment grade credit ratings by the major credit rating agencies. Furthermore, Ofgem should stress test the behaviour of financial ratios under adverse shocks. We welcome the opportunity to work with Ofgem to develop the financial model which will be used

for assessing the effect of the revised price control on the financeability requirements of the licensees.

Additionally, it is clear that the rating agencies are now placing more emphasis on a broader range of financial ratios than Ofgem have traditionally used. For example, in a recent report[2] Moody's states:

> "For regulated utilities in the UK, the two most important measures that we utilize in assessing the financial strength are the adjusted interest cover ratio (after deducting from post-tax cash flows the capex spend required to maintain the RAV) and the ratio of the debt to the RAV."

Also, in a Special Report[3] following DPCR4, FitchRatings commented:

> "Fitch analysis currently focuses on EBITDA rather than FFO."
> and
>
> "Net debt/RAV is the key measure of gearing for regulated utilities and the best cross-DNO or cross-industry indicator of leverage. However, it is not a good early indicator of problems in a company or misalignment versus the regulatory template and EBITDA-based measures are much better for the early identification of a trend."

The lower the level of a company's current credit rating then the higher the probability that it could be downgraded to below investment grade, at some future date. If the majority of ratings were BBB there would be a significant risk that one or more companies would fall below investment grade, in the event of future downgrades. Furthermore, in view of the higher yields which are required by investors on the debt of companies with lower ratings, it is unlikely that lowering ratings to BBB would reduce the weighted average cost of capital (WACC).

In addition to debt related financial ratios, we believe that Ofgem should also consider equity related ones. In particular, the dividend cover ratio should be adequate and the prospective dividend yield and growth should be consistent with the return required by shareholders.

[2] UK Independent Gas Distribution Companies: Similar Fundamentals to Regulated Water at Slightly Lower Leverage, Moody's Investor Service, March 2004
[3] No Shocks – The UK Electricity Dist'n 2005-2010 Price Review, Fitch Ratings Ltd, December 2004

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?

The precedent established in the most recent distribution price control reviews for resolving the depreciation "cliff face" problem must be extended to all companies at this review i.e. revenue profiles should be smoothed by accelerating depreciation for post-vesting assets (tilted depreciation). This will ensure price stability over the price control period and beyond, and will mitigate against the short-term financial impact on companies that would otherwise result.

It is worth noting that any introduction of revenue drivers will exacerbate the financeability issues that companies will face in the price control period commencing in 2007/08. To ensure that companies keep within investment grade criteria ratings consistent with those applied by the major credit rating agencies an alternative solution to the financeability issues would be to uplift cash flows by introducing a mechanism similar to that applied in the water industry and to Seeboard in the distribution review.

Tilted Depreciation

This approach is consistent with the precedent established in the most recent distribution price control reviews for resolving the depreciation "cliff face" problem and should be extended to all companies at this review i.e. revenue profiles should be smoothed by accelerating depreciation for post-vesting assets. This will ensure price stability over the price control period and beyond, and will mitigate against the short-term financial impact on companies that would otherwise result. In order to ensure that companies are neutral to this switch in NPV terms it is also necessary to make an adjustment for the different values implied by the different lives. The difference between asset values using the existing asset lives and the accelerated asset lives should be calculated and the difference would be added to depreciation in equal instalments over the next 15 years. If accelerated asset lives of 20 years are combined with the smoothing of the differences over 15 years, the resulting "cliff face" percentage drop in depreciation is consistent with the equivalent precedent drop in the distribution price control review.

Do Nothing

This would have a marked effect on the cash flow SP Transmission is able to generate from operations and will increase its requirement for external finance to fund future capital expenditure. This increased pressure to obtain external funds would undermine the financial stability of SP Transmission at a time when we will be undertaking significant new investments. This is clearly not acceptable.

Repex

Having an operating cost allowance for a proportion of capital expenditure incurred to replace existing assets is not appropriate due to the large proportion of

such expenditure that would have to be expensed. This would introduce a significant distortion to the incentives faced by companies.

We agree with Ofgem's recognition that this approach places an increased burden on present day consumers instead of sharing the burden with future customers who will equally share the benefits of the investments. As a result, adopting this approach would contradict Ofgem's duty to protect the interests of consumers as it would result in immediate higher costs to consumers rather then spreading the cost of these assets over their regulatory asset life. Therefore repex is not an appropriate solution.

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

In our view, the current ring-fencing arrangements, which are in place for DNOs in the electricity sector, would be sufficient for the Scottish TOs. We would therefore expect the wording of the relevant proposed TO licence condition to follow that already in place for the DNOs.

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

Pension costs are a feature of the nature of the members you have i.e. age profile, salaries, mortality experience, length of service and on the assumptions you make about future trends and assumptions about demographic and economic / financial trends including wage and price inflation, investment performance and investment returns. Pension schemes will also have different benefits built into the scheme rules and different investment return experience due to different asset mix and managers. A benchmarking solution will not alter the underlying fact that Licensees will incur pension costs driven by these facts and assumptions.

As a result we believe the only way to ensure that pension costs are correctly funded is by looking at each Licensee's pension related costs on an individual basis. We believe that benchmarking is not appropriate

Question 8.8: Should there be any ex post adjustments to the licensees' revenue allowances for tax payments?

We support the ex ante approach to tax which was adopted for DPCR4. However, we would expect significant changes in tax law or applicable tax rates or allowances to be taken into account, if and when they occur.

APPENDIX 1 – Capex Rolling Incentives

We support the use of a rolling incentive mechanism for capital expenditure which would allow us to retain up to 60% of the present value of the cost savings.

The rolling capex incentive mechanism should ensure consistency of the strength of the incentive to make efficiency savings throughout the price control period. However, we do not consider it sufficient to assess such an incentive mechanism simply in terms of the length of the lag in a basic rolling mechanism. This is because a fixed lag of, say, 5 years, does not provide the same strength of incentive for efficiency. Furthermore, the strength of incentive for efficiency in capital expenditure resulting from a basic rolling mechanism depends on the depreciation rate, as well as the length of the rolling retention period.

It is more appropriate to assess the strength of an incentive for efficiency as the proportion of the present vale of cost savings which are retained by the company, rather than simply the length of the period for which they are retained.

With no tax, the incentive strength associated with the basic capex rolling scheme is:

$$\textit{incentive strength} = 1 - [(1 - \textit{lag}/\textit{life}) / (1 + r)^{\textit{lag}}]$$ where:

lag is the rolling lag in years;

life is the deemed asset life in years;

r is both the allowed cost of capital and the specified discount rate.

Note that the above identity only holds if the specified discount rate is equal to the cost of capital. For example, if we assume:

lag = 5 years;

life = 40 years (the current life for post-vesting transmission assets); and

r = 5.545% (the Vanilla WACC as used in DPCR4)

then the incentive strength is:

$$\textit{incentive strength} = 1 - [(1 - 5/40) / (1 + 0.05545)^5] = 33.2\%$$

Note that this is less than that which would apply to distribution assets where the asset life, for regulatory purposes, is assumed to be 20, which gives a greater incentive strength of:

$$\textit{incentive strength} = 1 - [(1 - 5/20) / (1 + 0.05545)^5] = 42.7\%$$

This suggests that the following approach would be preferable.

1) Determine the optimal incentive strength expressed as the proportion of cost savings, relative to the allowances, which the company should be allowed to retain. Most assessments conclude that this should be in the range 40 to 60%.

2) Determine the length of the period over which the adjustment will be spread. In practice, this will need to be longer than the price control period. Otherwise complex adjustments would be required to take into account the actual expenditure for 2011/12, which would not be known when the price control from April 2012 is set.

3) Determine the adjustment mechanism to ensure that the present value of the cost savings retained by the company delivers the proportion of cost savings determined at (1). This could be achieved by:

    a) Incorporating a present value adjustment to revenues as part of the next price control determination, as was proposed for the implementation of the sliding scale mechanism for DPCR4. This would adjust revenues in the next price control period.

    b) Adjusting the RAV at the next price control review by an amount which preserves the present value. This would adjust revenues in the next and subsequent price control periods.

    c) Adjusting the percentage of the cost saving retained such that the present value of those retained over the retention period amounts to the optimal proportion determined in (1). This would allow revenues to be adjusted within the same price control period.

In principle, companies could be offered the choice of which adjustment mechanism they preferred. However, it is possible to combine these into a generalised incentive mechanism through the creation of a draw-down reserve. The would involve the addition of one (positive or negative) term to the price limits, which we term the incentive draw-down amount, which will be set by each company in each financial year. The draw-down amount would in turn be taken from a "draw-down reserve", to which (positive or negative) incentive contributions associated with differences between actual and allowed expenditure would be accumulated.

The roll-forward rules for the draw-down reserve need to ensure that present value neutrality is maintained. This is achieved simply by rolling forward the draw-down reserve:

$$DR_t = (1 + p_t)\,(1+r)\,DR_{t-1} - IA_t + IE_{t,}$$ where:

DR_t is the closing draw-down reserve for year t;

IA_t is the incentive allowance drawn during year t;

IE_t is the incentive entitlement earned in respect of year t;

p_t is the RPI inflation rate for year t; and

r is the designated (real) discount rate for incentive purposes.

Finally, as it is very difficult to implement "yardstick" comparison for the transmission licensees in Great Britain, the primary incentive for efficiency comes from the retention of out-performance relative to the allowance. This indicates that this incentive mechanism is even more important for encouraging cost savings in transmission than in distribution.