



SP Transmission & Distribution

Response to Ofgem Consultation Paper:

Transmission price control review

Initial consultation

July 2005

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Members of the ScottishPower group

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EXECUTIVE SUMMARY

This response is on behalf of SP Transmission. Our key messages for this price review are:

- Sufficient funding is required to meet our increased capital investment requirements,
- Regulatory funding arrangements must address uncertainty associated with the volume, location and timing of renewable generation connections,
- Our allowed cost of capital should reflect our increased risk exposure,
- Our operating costs are expected to rise as a result of cost pressures with limited scope for further efficiencies,
- New incentive mechanisms should target outputs that are within our direct control, and
- Our depreciation “cliff edge” should be addressed by the standard approach developed for distribution companies

Increased capital investment

This price control review will be characterised by a requirement for capital investment on a scale which is unprecedented in recent years. This increased level of investment is necessary to support the development of renewable energy in Scotland and undertake a major asset replacement programme required to maintain current levels of safety, security and performance.

Investment uncertainty

There is considerable uncertainty associated with the volume, location and timing of renewable generation connections in Scotland. In addition to the connections that are under construction or contracted, we are presently processing over thirty renewable generation connection applications in our area. The Scottish Executive and the UK Government’s desire to meet climate change targets suggest that many of these will proceed; however the exact number is uncertain since some of these will be postponed



or cancelled due to various external factors such as planning consents. This uncertainty can only be addressed through a flexible price control framework that ensures that infrastructure businesses are adequately funded with sufficient and stable returns to attract and retain equity funding.

Increased risk and impact on cost of capital

We believe the Scottish transmission businesses face significant financial challenges. The volume and uncertainty of investment and the introduction of BETTA together with new incentive arrangements increase the overall risk facing our business. Processing the significant numbers of generation applications in itself is a major source of risk regardless of how many proceed. The increase in industry-wide investment will lead to more competition for funds and so our ability to attract equity funding will be very important. Taking these factors into account, we see a justification for a cost of capital that is greater than that awarded to our distribution businesses in DPCR4.

Significant upwards pressure on operating costs

In recent years, SP Power Systems, on behalf of SP Transmission, has delivered significant efficiency savings, most recently through an internal Business Review programme. This led to a more commercially focused value chain splitting Service Provision from Asset Management and Asset Ownership activities. Specific initiatives under the Business Review included contract management economies and centralised planning and management.

As a mature transmission business, we have reached a point where, fifteen years after privatisation, the scope to reduce costs further is extremely limited.

Going forward we expect our operating costs to rise above RPI. This is primarily due to a growing asset base with an increasing asset age profile. In addition there are other significant upwards cost pressures that we are already experiencing, including contractor costs, fuel costs, oil costs (for transformers and switchgear), painting costs (towers and transformers), and health and safety legislation and environmental obligations.

**Incentives**

We are generally supportive of incentives principles. In our view incentive arrangements for transmission owners should be symmetric i.e. provide for rewards as well as penalties, and be based on output measures that are measurable and within our direct control.

Depreciation cliff-edge

During the next transmission price control period SP Transmission's pre-vesting assets will become fully depreciated. It will be essential for the management of cash flows that the impact of the "cliff edge" is minimised by appropriate smoothing of regulatory depreciation allowances once Vesting assets are fully depreciated. This was a major issue during DPCR4 for the England and Wales DNOs. We note the precedent for applying the smoothing mechanism established in DPCR3 was carried forward in DPCR4 and would expect the same mechanism to apply to transmission in this review.

The use of comparative analysis in this joint review

We do not believe that a joint review with gas will increase the scope for undertaking comparative analysis. We have commented in the past on the difficulty in undertaking comparative analysis in electricity transmission. Including gas would add to this difficulty. Even with Transco included, the limited number of companies with vastly differing characteristics would require 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.



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1. INTRODUCTION

This response to Ofgem's July 2005 Initial Consultation on the Transmission Price Control Review is submitted by SP Transmission. The following sections provide our comments on matters raised by Ofgem in their paper.

Our key messages for this price review are:

- Sufficient funding is required to meet our increased capital investment requirements,
- Regulatory funding arrangements must address uncertainty associated with the volume, location and timing of renewable generation connections,
- Our allowed cost of capital should reflect our increased risk exposure,
- Our operating costs are expected to rise as a result of cost pressures with limited scope for further efficiencies,
- New incentive mechanisms should target outputs that are within our direct control, and
- Our depreciation "cliff edge" should be addressed by the standard approach developed for distribution companies.

1.1 Increased capital investment

The next five-year period will be characterised by a requirement for capital investment on a scale that is unprecedented in recent years. This is driven by a number of factors, notably the increase in renewable generation in Scotland combined with the effect of revised charging methodologies.

Significant investment will be necessary to support the large-scale development of renewable energy in Scotland to meet Government targets. The network requirements arising from these targets have been partially addressed by the TIRG investment¹ in which major deep system reinforcements have been identified. However there will also be a requirement for a considerable increase in investment in local network infrastructure to link renewable generation to the main interconnected transmission system. It is also important to note that the impact of so-called "plugs" connections included in the GB charging methodology leads to significantly more capex being deemed infrastructure and therefore price controlled.

¹ See Ofgem's TIRG Final Proposals Paper of December 2004

Our approach to Asset Risk Management was commended by Ofgem during the 2002 Asset Risk Survey for which the business's strategy received positive feedback and was assigned to the "well developed all rounders" category. Our detailed assessment of future asset modernisation requirements has confirmed the need for a considerable increase in our non-load related investment compared with current levels. This work is necessary simply to maintain existing levels of safety, integrity and performance of an asset base which continues to age. This objective will be achieved through managing the condition of our high criticality transmission assets to reduce risk of unexpected failures.

In assessing overall expenditure requirements, it will be important to consider the impact on costs of the growth in transmission network infrastructure both in the UK and world-wide and the consequent demand on supplier and contractor resources. This increase in demand is likely to increase costs particularly in the short to medium term.

1.2 Investment uncertainty

There is considerable uncertainty associated with the volume, location and timing of renewable generation connections in Scotland. In addition to connections that are under construction or contracted, we are presently processing over thirty renewable generation connection applications in our area. The Scottish Executive and the UK Government's desire to meet climate change targets suggest that many of these will proceed; however the exact number is uncertain since some of these will be postponed or cancelled due to various external factors such as planning consents. This uncertainty can only be addressed through a flexible price control framework that ensures that infrastructure businesses are adequately funded with sufficient and stable returns to attract and retain equity funding.

1.3 Increased risk and impact on cost of capital

We believe the Scottish transmission businesses and in particular SP Transmission, face significant financial challenges across the next transmission price review. The commencement of BETTA has presented a number of issues including the introduction of a new and unique counterparty into our business model (NGC as GB System Operator), which has the effect of reducing the operational flexibility through which we manage and mitigate risk.

In addition the uncertainty in investment requirements associated with generator connection applications to the transmission system creates the potential for significant volatility in our business, our financing requirements and our credit statistics. Such unprecedented levels of connections together with the necessary increase in non-load related investment suggests that annual expenditure in our transmission business

could now significantly exceed that for SP Distribution where in the past the opposite was the case.

Ofgem have also indicated the desire to continue to place emphasis on regulating the “outputs” of network operators by introducing and extending incentive mechanisms. This introduces greater regulatory uncertainty and risk and hence places upwards pressure on the base cost of capital.

Taking all of these factors into account, we see a justification for a cost of capital that is greater than that awarded to our distribution businesses in DPCR4.

1.4 Significant upwards pressure on operating costs

In recent years, SP Power Systems, on behalf of SP Transmission, has delivered significant efficiency savings, most recently through an internal Business Review programme. This led to a more commercially focused value chain splitting Service Provision from Asset Management and Asset Ownership activities. Specific initiatives under the Business Review included contract management economies and centralised planning and management.

As a mature transmission business, we have reached a point where, fifteen years post-privatisation, the scope to reduce controllable costs further is extremely limited.

Going forward we expect our operating costs to rise above RPI. This is primarily due to a growing asset base with an ageing asset profile overall. In addition there are other significant upwards cost pressures including contractor costs, fuel costs, oil costs (for transformers and switchgear), painting costs (towers and transformers), and health and safety legislation and environmental obligations.

1.5 Incentives

Ofgem have exhibited a preference for regulating the “outputs” of network operators by introducing and extending incentive mechanisms. We support incentive principles but on the clear understanding that any incentive arrangements for transmission owners are symmetric i.e. provide equal opportunity for rewards as well as penalties, based on output measures that are measurable and within the direct control of the transmission owner (TO).

1.6 Depreciation cliff-edge

During the next transmission price review SP Transmission’s pre-vesting assets will become fully depreciated. It will be essential for the management of cash flows that the impact of the “cliff edge” is minimised by appropriate smoothing of regulatory

depreciation allowances once Vesting assets are fully depreciated. This was a major issue during DPCR4 for the England and Wales DNOs. We note the precedent for applying a smoothing mechanism established in DPCR3 was carried forward and would expect the same mechanism to apply to transmission in this review.

1.7 The use of comparative analysis in this joint review

We do not believe that a joint review with gas will increase the scope for undertaking comparative analysis. We have commented in the past on the difficulty in undertaking comparative analysis in electricity transmission. Including gas would add to this difficulty. Even with Transco included, the limited number of companies with vastly differing characteristics would require 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.

In our experience the most productive use of such studies 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, they are more appropriate as a cross-check rather than as a definitive method of deriving future operating costs.

1.8 Valuation of SPTL

Ofgem have provided information within Section 3 of the consultation document regarding our RAV, allowed revenue, capital expenditure and operating costs. We are concerned that these figures understate the value of our business.

The correct level of allowed revenue for the two-year extension is £318M at 2004/05 prices rather than £239m as quoted in paragraph 3.27. The difference is due to BETTA adjustments for both Interconnector and post-Vesting connection assets that were treated as excluded services prior to BETTA.²

² As detailed in Ofgem's December 2004 Final proposals and impact assessment paper



2. FRAMEWORK, CONTEXT AND OBJECTIVES

This section addresses Section 4 of Ofgem's consultation paper.

How should Ofgem seek to address the external factors in paragraph 4.11 in setting new price controls? Are there any other external factors that Ofgem should take into account?

The volume, location and timing of renewable generation are subject to considerable uncertainty, especially in Scotland. We propose that this should be addressed by the use of a supplementary component of the basic RPI-X control, which would allow for notification of additional schemes, modifications of planned schemes and removal of schemes which turn out not to be required.

Following the implementation of BETTA, responsibility for system operation has been transferred from SPT to the GBSO. Incentive schemes should reflect this change in responsibilities and be based on outputs that are measurable and within the direct control of SPT acting in its role as transmission owner (TO).

While the interaction of the gas and electricity transmission networks needs to be taken into account in this review, this does not imply that investment incentives should be similar in each case. For example, due to the fundamental differences between the gas and electricity sectors, there does not appear to be a convincing case for a capacity auction mechanism in electricity analogous to the long-term entry capacity auctions that apply in gas transmission. In particular, we do not believe it is appropriate to rely on entry capacity auctions to provide investment signals.

Is the standard model of a five-year control and RPI indexation still appropriate for the next transmission price controls? Are there any areas of activity which should be price-regulated differently, including any scope for de-regulation?

The optimal length of the transmission price control period is a balance between the degree of uncertainty surrounding future expenditure and the stability required to facilitate long term investment. The requirement for increased levels of investment through the next price control period and beyond suggests that there may be a case for extending the length of the transmission price control period, provided that a satisfactory way of dealing with uncertainty, especially that relating to renewable generation and future cost trends, can be developed. We envisage that such a mechanism would require a supplementary component to the basic RPI-X price control, together with the possibility of formalised interim determinations, as used in the water industry. However, until the degree of uncertainty has been quantified and potential supplementary mechanisms developed, it is too early to determine the optimal length of the transmission price control period.

In contrast to distribution, transmission network investment tends to be dominated by a relatively small number of high value schemes. We believe there is a strong case for schemes that have been specified in advance, at the time of the transmission price control review, and for which delivery is largely within the control of the TO (e.g. non-load related asset modernisation) to be treated in a manner similar to the schemes within Ofgem's Transmission Investment for Renewable Generation (TIRG) proposals. This would provide scope to combine efficiency incentives with an appropriate degree of risk reduction in the event of changes in external factors outside the control of the TO.

What particular areas of the licensees' activities should Ofgem focus on in this review?

While there is clearly an ongoing requirement to assess operating cost efficiencies, the changing demands on the transmission businesses as a result of external factors means that this review should focus on the investment requirements of the licensees.

The recent review of the DPCR4 process emphasized the importance of conducting analysis in an open and transparent manner and ensuring that adequate time is allowed for Ofgem and its consultants to consider submissions by the companies.

Should incentives to reduce costs be strengthened or weakened?

We anticipate significant upwards pressure on operating costs during the next price control period with only limited scope for further efficiencies. Consequently it would appear appropriate to strengthen incentives to reduce costs by allowing companies to retain a greater proportion of the present value of cost savings.

How should the range of refinements to the basic RPI-X form of control be deployed by Ofgem in setting the next transmission price controls? Are there any refinements that should be used more or less than is currently the case?

The existing range of excluded services should be maintained.

We do not believe that a simple revenue driver, such as the Gt^3 term, is the most appropriate way of addressing the uncertainty surrounding the volume, location and timing of renewable generation which will require to be connected in Scotland.

³ As provided for in NGC's licence

Any additional incentives for companies to improve the accuracy of capital expenditure forecasts must be introduced ex-ante (i.e. in advance of the FBPO submission) to be effective. The manner in which accuracy is assessed also needs to be carefully considered. Undue emphasis on a single benchmark (e.g. such as in Ofgem's sliding scale mechanism which was introduced part-way through DPCR4), can result in misleading conclusions regarding the validity of company forecasts and may encourage inappropriate behaviour by companies.

Consideration needs to be given to the interaction between the various incentive and adjustment mechanisms. For example, the addition of a revenue adjustment term to reflect the volume of generation connected to the network would need to be taken into account when designing a rolling mechanism for capital expenditure.

Are rolling incentives appropriate for transmission, and if so how long should the retention periods be for efficiency savings? Should the rolling incentive approach adopted in gas for incremental entry capacity also be adopted in electricity?

In principle, we support the introduction of a rolling mechanism which would remove the periodicity associated with fixed term price control periods. However, we recognise that a rolling mechanism needs to be designed very carefully if it is not to introduce a distorting influence between operating and capital expenditure. In general, simply using the same retention period for operating costs and capital expenditure would not ensure that the strength of incentives for efficiency in both is equalised. Furthermore, the incorporation of a revenue adjustment term, (such as G_t in NGC's price control) into a rolling mechanism is likely to lead to a very complex calculation).

In practice, the lag used in a rolling mechanism needs to be longer than the price control period. Otherwise, complex adjustments are required to take into account the outcome of the last year of the previous price control period which would not be known when the price control for the next price control period is set.

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 period for which they are retained. Most assessments conclude that the optimal proportion of cost savings, relative to the allowances, to be retained by the company should be in the range 40 to 60%.

We do not consider that it is appropriate, for electricity, to adopt the approach to incremental entry capacity for gas. There are many more entry points on the electricity transmission network and most of these do not have a sufficient number of interested parties to support an informative auction. Moreover, we have severe doubts about the ability of auctions to signal accurately long term capacity requirements for electricity.



Nevertheless, in so far as incremental capacity is initially funded through a supplementary price control mechanism, there will need to be a pre-determined approach to funding that capacity over its remaining life. One approach would be to incorporate such capital expenditure into the RAV at a pre-determined future date.

Should Ofgem seek to ensure that the strength of incentives for efficiency in operating costs and capital expenditure is equalised?

In principle, we would support the equalisation of the strength of incentives for efficiency in operating costs and capital expenditure, as this would avoid any potential incentive to distort expenditure decisions.

Equalisation can be achieved by de-coupling the capital expenditure variances from the RAV. This removes the distortions arising from timing, from differences in the treatment of capital expenditure and operating expenditure, and from any differences in regulatory asset lives among companies. Instead, all cashflow variances are accumulated in a separately identified “regulatory reserve” which is then written down over time, as the benefits of efficiency savings are passed through to customers.

Are Ofgem’s objectives for the price control review appropriate and comprehensive? If not, how should the objectives be re-stated?

We would welcome explicit reference to the principles of best regulatory practice, namely: proportionality, accountability, consistency, transparency and targeting.



3. ASSESSING COSTS

This section addresses Section 5 of Ofgem's consultation paper.

Capital expenditure

What methods and models of capital expenditure cost assessment should Ofgem seek to use in the transmission price control review?

Non-Load Related Expenditure

While we would expect Ofgem to use a generic (e.g. age related) model as a guide to investment requirements in the medium to long term, it is important that short-term requirements and priorities are also taken into account. We believe that this can only be effectively achieved by a review of our proposed work programme and specified projects for the price control period. This approach is necessary to take account of asset and site specific priorities that have been identified through application of our Asset Risk Management (ARM) methodology, including asset criticality, performance and condition assessment.

Load Related Expenditure

Load related capital expenditure is driven by general system reinforcement requirements and connection requirements. In order to assess general system reinforcement requirements, it is necessary to take into account NGC's planning assumptions which include the current and predicted contracted generation and future demand forecasts. This information is used in models of the network in which tests for compliance with GB security and quality of supply standards are applied. Deficiencies identified are highlighted for further consideration.

For system reinforcement and new connection projects, the opportunity to rationalise the network and coordinate with asset replacement requirements is taken during the detailed project engineering phase in order to develop the most economic overall solution.

Due to the complexities of modelling the transmission network and the need to take full account of the factors mentioned above, we believe that it would be extremely difficult for Ofgem to undertake a meaningful "top down" assessment of load related investment requirements. An alternative, more satisfactory approach is for Ofgem to undertake a detailed review of the specified projects and supporting information presented by SPT within our work programme.

What might an increasing importance of non-load related capital expenditure (as opposed to load related capital expenditure) mean for how Ofgem undertakes the price control review?

The price control framework must ensure that there is sufficient funding for the considerable increase in both non-load related and load related capital expenditure. The framework must promote efficient investment rather than encourage deferral.

How, if at all, should Ofgem adapt its approach to assessing capital expenditure requirements related to growth in renewable and distributed generation and future plant closure?

There is a high degree of uncertainty associated with future expansion of renewable generation connected to the transmission and distribution systems, and the funding required during the next price control period.

As a transmission licensee operating under the STC, we are required to act on information received from NGC with regard to future generation and demand forecasts. In view of the uncertainty we examine high and low scenarios based on the central case offered from NGC. As we have already noted, we recommend that Ofgem assess projects provided by SPT. These projects will be supported by detailed information including modelling results, connection applications, and options decision process.

Does the assessment model adopted for TIRG provide a useful model for the price control review?

In principle, comparing capital investment to avoid constraint costs when making an investment decision is a sensible approach. While we support the methodology applied under TIRG, we would comment that the process suffers from a lack of transparency and is very sensitive to assumptions around the future generation position and constraint costs.

The main driver for transmission investment should be system security, i.e. there should be sufficient investment in transmission capacity to ensure compliance with the Security and Quality of Supply Standards to ensure that system security is not compromised by future expansion of renewable (or other) generation. However, there is considerable merit in carrying out a cost benefit analysis of major infrastructure projects required to support renewables using a methodology consistent with that applied under TIRG as long as robust assumptions can be agreed. The trigger for a specific project to be categorised as justified in any such analysis should be contracted generation i.e. generation that has accepted a connection offer.

Operating costs

What particular areas of operating costs should Ofgem focus on in its assessment of the current and future efficiency of the transmission licensees?

The controllable operating cost base of the two Scottish transmission businesses is relatively small. We believe that Ofgem should focus on the total cost of carrying out network activities although this will require compliance with the definition of activities across the industry and take account of factors which differentiate the Transmission businesses such as economies of scale and geographic operating area.

What approaches, other than those identified in this chapter, might be available to Ofgem in assessing the efficiency of each transmission licensee's operating costs?

We are not aware of any other approaches that would be appropriate.

Cost reporting

What form of cost reporting framework should Ofgem develop for each of the transmission licensees as a means of monitoring performance under the new price controls over time?

The new cost reporting process for DNOs has been implemented for the first time for the financial year 2004/05. It is the intention of Ofgem and the DNOs to improve this process over time. We believe that the DNO cost reporting framework is broadly appropriate for our transmission business but the industry will need to work with Ofgem to develop the data sets which are most meaningful and relevant for inclusion in the cost reporting pack.

4. INCENTIVES

This section addresses Section 6 of Ofgem's consultation paper.

How should Ofgem encourage users and potential users of the system to signal their future requirements and how should the licensees be incentivised to meet these requirements?

In our view, sound planning and appropriate security standards, together with informed forecasts of the changing pattern of generation and demand, should guide long-term investment.

Short run signals are not necessarily stable enough or timely enough to guide efficient investment in long term assets, such as transmission lines.

We do not believe it is appropriate to rely on entry capacity auctions to provide investment signals.

Is there a need for consistency between gas and electricity transmission and between arrangements for entry to and exit from the networks?

There are substantial differences between entry to and exit from the networks for gas and electricity networks. It is much easier to assess the requirements for entry to the gas network at a limited number of nodes. In electricity, it is not possible to assess accurately future requirements at each of many nodes. Moreover, the split between the GBSO and the TOs in electricity complicates and further reduces the applicability of an auction-based approach, as both the GBSO and the TOs would need to be incentivised in a consistent and equitable manner.

Also, it is important that an appropriate degree of consistency is maintained between transmission and distribution. In particular, the 132kV networks, which are part of Transmission in Scotland, are treated as Distribution in England and Wales.

To what extent should new users of the networks be required to make a firm financial commitment before the Transmission licensee is required to make capacity available to them?

We believe that it is important to get the balance right between a user making a financial commitment and unreasonable barriers.



However this is not a direct issue for SPT as it is NGC as GB System Operator (GBSO) that must enter into appropriate commercial arrangements with users. Under the BETTA arrangements, our contract for the construction of the user's connection and associated local infrastructure is with the GBSO. We therefore require a firm financial commitment from the GBSO to cover our full costs during the construction phase and would expect the GBSO to back-off this liability in their user agreement/s under the CUSC.

How should baseline outputs and incremental outputs be defined for (a) electricity transmission licensees, and (b) Transco NTS? Should the existing definitions be retained? If not, how should they change?

For electricity, account must be taken of the substantial but uncertain amount of renewable generation which will require to be connected during the forthcoming price control period. In addition to those generation projects that will have accepted connection offers before the price control is set, there will be others at various stages of offer or enquiry.

We support the range of output measures which were developed for the additional capacity to be delivered by TIRG projects, namely:

- MVA capability for each line (for defined ambient temperature/season)
- line resistance, and
- line reactivity.

These could be supplemented by other output measures for other types of projects, as necessary.

How should the provision of incremental outputs be remunerated? Should NGC have a similar incentive to Transco NTS in respect of incremental capacity, i.e. that it is rewarded for providing future capacity based on firm commitments by network users to pay?

When Ofgem first consulted on the potential application of the Transco NTS capacity incentive to electricity we observed a considerable amount of legitimate concerns and strong views expressed by the respondents. Examples were:

- Many felt that there was no convincing argument to support the introduction of this incentive scheme, which will introduce both a greater degree of complexity and increased costs with no estimate of benefits to the final customer;

- One respondent pointed out that the introduction of such a scheme implied the end of NGC Planning Standards and will have implications for their nuclear safety cases;
- There is a lack of any justification for the view that gas and electricity incentive schemes need to be identical, a point obvious to many of us given the differences between the characteristics of the networks;
- There will be no market for exit capacity rights;
- The widespread view that the CUSC is the appropriate way to progress transmission access developments; and
- The lack of any existing operational problems caused by the current access regime.

We believe that these concerns still exist today as much as they did during previous consultations.

Is there a need for greater use of explicit output measures and performance indicators as part of the next price controls? If so, what areas should such new output measures focus on?

The development of supplementary price control mechanisms, such as one which could be designed to fund investment required to connect renewable generation, will need to be linked to corresponding output measures. In electricity, relevant output measures, such as those for system reliability, may well be different for the GBSO and the TOs, as the GBSO and the TOs have different aspects of performance under their own control.

Only output measures which are directly under an operator's own control are suitable for the development of incentives. In addition, such output measures should be precisely defined and be capable of accurate measurement. Furthermore, the focus should be on those measures which customers care most about.

To what extent should Ofgem set price controls in the expectation that they will need to be re-opened in the light of future events, or should Ofgem as far as practicable seek to set price controls which adjust revenues automatically as circumstances change?

In view of the high level of uncertainty surrounding developments over the next few years, it seems unlikely that automatic adjustments to revenue could be designed and calibrated to cover all eventualities. We, therefore, believe that a variety of mechanisms should be considered, including provision for income or asset adjusting events and formalised interim determinations, as well as automatic adjustments to revenue, where appropriate.



5. FINANCIAL ISSUES

This section addresses Section 7 of Ofgem's consultation paper.

Should Ofgem's approach to cost of capital tax under DPCR4 be adopted for the TPCR?

We believe that it is appropriate for the approach adopted under DPCR4 to be applied to the TPCR.

What are the reasons why the cost of capital for a transmission business might be different to the cost of capital for a distribution business?

We believe that the Scottish transmission businesses and in particular SP Transmission, face significant financial challenges across the next transmission price review. The move to a shallow connections model combined with the fact that in our franchise area we are seeing significant increases in generator connection applications to the transmission system (presently totalling almost 6 GW in our area), necessary to meet the governments renewable targets creates significant volatility and stress on our business, our financing requirements and our credit statistics. Such unprecedented levels of connections together with the necessary increase in non-load related investment suggests that annual expenditure in our transmission business could now significantly exceed that for SP Distribution where in the past the opposite was the case.

The commencement of BETTA has presented a number of issues including the introduction of a new and unique counterparty into our business model (the GBSO), which has the effect of reducing the operational flexibility through which we manage and mitigate risk.

We also note that Ofgem continue to reflect an emphasis on regulating the "outputs" of network operators by introducing and extending incentive mechanisms. While there is a net benefit, this introduces in greater regulatory uncertainty and risk and places upwards pressure on the base cost of capital in our view.

Taking all of these issues under consideration we see a justification for a cost of capital that is greater than that awarded for our Distribution business in DPCR4 and we are committed to working with Ofgem on this matter.



What principles should Ofgem apply in rolling forward RAVs, in particular in respect of capital expenditure in excess of past allowances, and in respect of changes to how costs are accounted?

We believe that where expenditure has necessarily and efficiently been incurred it should be rolled forward into the RAV irrespective of whether or not it was previously allowed by Ofgem. Where it can be proved conclusively that a change in accounting for costs would result in the customer paying twice if the expenditure was rolled forward into the RAV then this should be disallowed.

Are there any other factors which Ofgem should consider in assessing financial issues under this price control review?

During the next transmission price review SP Transmission's pre-vesting assets will become fully depreciated. It will be essential for the management of cash flows that the impact of the "cliff edge" is minimised by appropriate smoothing of regulatory depreciation allowances once Vesting assets are fully depreciated. This was a major issue during DPCR4 for the England and Wales DNOs. We note the precedent for applying a smoothing mechanism established in DPCR3 was carried forward in DPCR4 and would expect the same mechanism to apply to transmission in this review.