SP Transmission & Distribution

Response to Ofgem Consultation Paper:

Electricity Distribution Price Control Review
Second Consultation – December 2003

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EXECUTIVE SUMMARY

This distribution price control review is reaching a critical stage with Ofgem's principles paper due in March 2004 and initial proposals due in June 2004.

As stated in previous consultation responses, this price review is different from previous reviews. Increasing costs in a number of areas, including distributed generation and network investment, will result in upward pressure on prices. Ofgem must take proper account of these differences when developing its principles and proposals for the price review outcome.

The key issues are as follows:

- a sufficient and stable return is required to attract and retain equity funding;
- a forward looking framework is required to fund network investment associated with distributed generation and ensure that Government targets on renewable energy can be met;
- allowed investment must be increased to secure the long-term safety, reliability and sustainability of the electricity infrastructure; and
- a sound and transparent approach to efficiency analysis is required to ensure adequate funding.

These issues are addressed in more detail below.

COST OF CAPITAL

An increased cost of capital is strongly supported by market evidence, recent regulatory determinations and authoritative academic studies.

- A higher cost of capital will promote future investment confidence and incentives.
- An increase in the assumed level of gearing used to set the allowed cost of capital is not appropriate as it would reduce the allowed cost of capital and most likely result in increased levels of debt across the industry.
- A pre-tax approach to cost of capital must be retained, with the tax allowance set at an appropriate level based on the average industry position, to provide the correct incentive to maintain tax liabilities at an efficient level in the medium to long-term.

DISTRIBUTED GENERATION (DG)

Ofgem's current proposals for funding investment associated with Distributed Generation will not be effective in delivering the necessary investment in our licensed areas and would, if implemented, significantly undermine the Government's energy policy targets.

- The current proposals would force companies to adopt a short-term approach to network reinforcement resulting in sub-optimal investment and barriers to the connection of DG in areas rich in renewable resource.
- We have proposed an alternative approach combining a programme of deep reinforcement and an amended hybrid mechanism.
- We believe that this alternative approach will meet Ofgem's objectives and will be the most effective means of facilitating Government policy while minimising the risks to both customers and companies.

NETWORK INVESTMENT REQUIREMENTS

Allowed investment levels must be increased to secure the long-term safety, reliability and sustainability of the electricity infrastructure.

- Investment plans presented in our Forecast Business Plan Questionnaires (FBPQs) are the next stage of longer-term plans to maintain network performance, safety and reliability for our customers in the SP Distribution and SP Manweb areas.
- These plans, focussed on critical assets, are the output of robust and detailed Asset Risk Management processes and will require the commitment and support of Ofgem over the period of the next three price controls.

ASSESSING COSTS AND EFFICIENCY

A robust approach, that does not rely on any single measure and takes proper account of regional and inherited factors, is required.

- Simplistic analysis of past cost-trends would result in serious misrepresentation of the future potential for cost reductions.
- Transparency is essential in order to enable companies to understand Ofgem's analysis and conclusions.

In addition to these key, high-level issues, there are a number of other important issues that require to be satisfactorily dealt with, including:

- **Treatment and Funding of Fault-Related Expenditure**

Our research and analysis suggest that fault-related replacement expenditure has not been adequately funded in the current price control.

– We agree with Ofgem's principle that customer's should not pay twice for any service but would emphasise that all properly incurred expenditure must be funded.
– Expenditure during the current price control period on post-fault asset replacement is capital expenditure that must be included in the RAV.

- **Depreciation Cliff-Edge**

  The approach used by Ofgem to smooth the revenue profiles of those companies that faced this issue at the last review must be extended to all companies.

– Revenue profiles should be smoothed by accelerating post-vesting depreciation.
– Early clarity is required on Ofgem's proposed treatment of this important issue.

We look forward to publication of Ofgem's latest thinking on these issues, and on the many other important issues for this price review, in the March consultation paper. We remain committed to working with Ofgem and the rest of the industry to deliver a successful price review outcome that balances the interests of customers, shareholders and all other stakeholders. We hope that our comments in this response document will prove helpful in meeting this objective.

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SECTION 1: TIMETABLE AND CONSULTATION PROCESS

1.1 We note the progress that has been made against Ofgem's timetable and welcome the fact that Ofgem has met the output milestones set out in the October Consultation Paper. However, we would point out that much has still to be done and the timetable remains extremely challenging with little or no scope for slippage. As stated in previous consultation responses, all parties must work together to ensure delivery and enable the production of robust final proposals within the available timescales.

1.2 The price review is reaching a critical stage:

- companies have submitted Historic Business Plan Questionnaires (HBPQ) and Forecast Business Plan Questionnaires (FBPQ);
- Ofgem has visited companies to discuss their HBPQ submissions;
- further visits are scheduled to review FBPQ submissions, cost assessment and operational efficiency; and
- initial proposals are due to be published in June 2004.

1.3 The findings of Ofgem's analysis and reports from the various visits must be made available to companies at the earliest opportunity. This is essential in order to provide companies with sufficient time to consider this information, correct any inaccuracies or misunderstandings and respond to Ofgem before it is made public or initial proposals are produced.

1.4 We note from the latest timetable that Ofgem intends to publish a report on the price review process for consultation in the early summer of 2005. We fully support a review of the process, as it is important to identify and act upon lessons learned from previous reviews. However, it is not appropriate for Ofgem to review its own process. An independent body reporting to the Authority should conduct this review, informed by comments from all interested parties, including Ofgem. This will ensure that all stakeholders obtain maximum benefit from this exercise.

SECTION 2 - FORM, SCOPE AND CONTENT OF PRICE CONTROL

2.1 REVENUE DRIVER

2.1.1 As set out in previous consultation responses, we are concerned that there is uncertainty around the future levels of units distributed. This uncertainty arises as a result of a number of factors including distributed generation, and incentives for loss reduction and energy efficiency.

2.1.2 We continue to believe therefore that the revenue driver should be based entirely on customer numbers rather than on a combination of customer numbers and units distributed. The basis for customer numbers used in the revenue driver should be actual customer numbers as defined in the RIGs (Regulatory Instructions and Guidance).

2.1.3 We note Ofgem's comment that, in some cases, costs may be more closely related to capacity than to units distributed. However, a revenue driver based on network capacity is not appropriate due to the difficulties around definition and measurement of network capacity.

2.2 NGC EXIT CHARGES

2.2.1 NGC exit charges are non-controllable costs from the perspective of a distribution business and, as such, are not suitable for the application of an incentive regime, however limited. It is not appropriate for companies to be faced with a risk of under-recovery of these charges.

2.2.2 The current regulatory regime is sufficient to ensure that NGC connection work is necessary and the corresponding charges are set an appropriate level. Although, in theory, there might appear to be some scope for companies to influence the level of these costs, this is very limited in practice.

2.2.3 We do not believe that there is any evidence that the treatment of NGC exit charges as pass-through weakens either:

- incentives for efficiency;
- incentives for the development of local networks; or
- incentives for the take-up of distributed generation.

2.3 WHEELING CHARGES

2.3.1 Our previous consultation responses have pointed out that the current regulatory regime provides no mechanism for the recovery of charges incurred for energy 'wheeled' across the network of another distribution company. We are pleased that Ofgem have recognised this anomaly and would reiterate our view that these charges should be treated as full pass-through. We urge Ofgem to make this change as soon as possible and to give proper consideration to allowing recovery of the costs incurred during the current price-control period.

2.4 EHV CHARGES

2.4.1 We note the options that Ofgem is considering in the treatment of EHV charges, and the statement that arguments in favour of a continuation of the current treatment of such charges are not convincing. We would comment that there appears to be no reason for change and that customers' interests will be best protected by the continued treatment of EHV charges as excluded from the price control.

2.4.2 We note Ofgem's comments on the wide range of movements in the average EHV charge per unit. We would caution that such analysis is not valid as EHV costs are asset driven rather than unit driven.

2.4.3 We are concerned that the inclusion of EHV charges in the price control, perhaps with a unit or capacity based revenue driver, could limit the ability of both parties to agree site-specific charges. This would not be in the interests of customers.

2.4.4 Ofgem has set out a number of options that could be implemented to improve the current regime:

- the inclusion of EHV charges in the price control;
- the publication of explicit guidelines on how EHV charges should be set; and
- obligations on companies to publish or provide information on EHV charges on a regular basis.

These options are addressed in the following paragraphs.

Inclusion in the Price Control

2.4.5 We believe that the current arrangements provide at least the same level of protection for EHV customers as is provided to other customers by the price control. As previously stated, it is not clear to us how a price control for such charges would operate, however we remain concerned that that this could limit the ability of the customer and the company to agree site specific charges.

Publication of Explicit Guidelines

2.4.6 At the last price control review, Ofgem set out high-level guidelines on the basis for EHV charges. These guidelines have been followed by both of our licensed business.

2.4.7 It should be noted that these guidelines were published in the various price review consultation documents and, as such, might not have been made clear to EHV customers. We would support the publication of explicit guidelines and their inclusion in charging statements as this could aid transparency. However, any changes to the current guidelines would have to be the subject of a full consultation process.

Publication of Charging Information

2.4.8 We are not convinced that the publication of charges or related information will be of significant benefit to any party but have no objection to publication providing that customers have provided their consent. We are aware that some customers regard such charging information as commercially confidential and consequently may not approve of its release into the public domain.

2.5 NON-CONTESTABLE CONNECTION CHARGES

2.5.1 We are committed to the satisfactory introduction of competition in connections and continue to believe that its development, and the interests of customers in general, will be best served by continuation of the existing arrangements and the introduction of appropriate performance standards.

2.5.2 We note Ofgem's statement that it expects to develop further standards in this area. As set out in previous consultation responses, the following principles are fundamental to the introduction of a satisfactory regime:

- standards must be clearly defined to enable accurate and consistent measurement and reporting;
- implementation costs must be fully funded;
- the number of standards must be proportional to those in place for other company activities, based on the value and relative importance;
- targets should only be finalised when robust and auditable statistics are available to verify reported performance, when a decision can be taken on whether to include payments; and
- it must be made clear to all parties that failure to meet service standards will not result in liability for consequential loss.

2.5.3 Appropriate performance standards, focusing on the critical parts of the business process, are as follows:

- the time to provide a firm quotation;
- the time to approve the contestable works design; and
- the percentage of non-contestable work requests completed on the agreed date.

2.5.4 In addition, we believe that it will be necessary to review industry processes from the perspective of the end customer to ensure that a satisfactory service is provided.

2.6 BUSINESS RATES

2.6.1 As set out in previous consultation responses, business rates are non-controllable costs from the perspective of a distribution business and, as such, are not suitable for the application of an incentive regime, however limited. It is not appropriate for companies to be faced with a risk of under-recovery of these costs.

2.7 DEALING WITH UNCERTAINTY, NEW OBLIGATIONS AND COSTS

2.7.1 We are disappointed with the lack of progress made on this issue and believe that a formalised approach, similar to that adopted in the water industry, is appropriate. In our view, such formal mechanisms represent best regulatory practice and are in the best interests of all stakeholders. Ofgem has provided no satisfactory arguments to support the position that formal mechanisms are not required.

2.7.2 The December consultation paper refers to the differences between the statutory duties of Ofwat and Ofgem and suggests that formal mechanisms may not be appropriate because of these differences. In our view these differences are overstated. In addition, we believe that this section of the consultation paper is misleading with respect to Ofgem's statutory duties, as it does not mention the obligation, set out elsewhere in the consultation paper, to have regard to the need to secure that licensees can finance their obligations.

2.7.3 We reiterate the comment set out in previous consultation responses that, in order to remove the perception of regulatory risk associated with additional costs and new obligations, Ofgem must set out clear rules for dealing with cost increases between price reviews including:

- the circumstances under which the various mechanisms (such as error correction, interim adjustments, recovery during subsequent price controls) would be applied;
- the circumstances under which pass-through would be appropriate, and those under which efficiency tests would be applied; and
- the criteria that would be used to assess cost efficiency.

2.8 INCENTIVE FRAMEWORK

Efficiency Incentives

2.8.1 We continue to have a number of significant concerns regarding Ofgem's proposals for rolling mechanisms. As set out in responses to previous consultations, we have developed detailed and practical proposals for a rolling mechanism that de-couples capital expenditure savings from the RAV. This removes the distortions arising from timing, from differences between capital expenditure and operating expenditure incentives and from differences in regulatory asset lives.

2.8.2 We are therefore disappointed that, at this late stage in the consultation process, Ofgem appear to have settled on a rolling mechanism linked to the RAV without mention or consideration of potential alternatives in any of their consultation documents. We urge Ofgem to give full consideration to all of the alternatives before finalising the principles of the rolling mechanisms.

Retention of Efficiencies

2.8.3 We agree with Ofgem that incentives for efficiency need to be balanced against incentives to deliver the required outputs and note their intention to make the retention of capital expenditure efficiencies conditional on companies meeting their quality of supply obligations. While we support the view that there should not necessarily be a mechanistic link with performance against 04/05 targets, we are concerned that there might be scope for subjective assessments. We would therefore urge Ofgem to clearly set out the rules that will be applied. In our opinion it is not only appropriate to consider performance against quality of supply targets, performance against Ofgem's Asset Risk Management Survey should also be considered.

2.8.4 We note that Ofgem does not intend to apply a similar test to operating costs efficiencies made during this price control period but is considering the application of such a test for the next price control period. We would reiterate our concerns regarding a subjective assessment and the need for a clear set of rules to be applied. If clear rules can be established then appropriate outputs would include quality of supply and telephone response.

Scope for Further Efficiencies

2.8.5 Ofgem refers to performance against the current price controls and concludes that there is no strong evidence that incentives for efficiency need to be increased or weakened. However this approach ignores the fact that future scope for efficiencies is limited. It is more important to focus on the future scope for efficiencies, rather than on past performance, when considering incentive strength.

2.8.6 Incentives to achieve efficiency savings need to be strengthened to ensure that customers continue to benefit from efficiency gains. Future gains will require greater effort and innovation and many initiatives will require up-front expenditure to stimulate future cost savings.

2.8.7 Controllable costs now represent a far smaller proportion of total costs than at previous reviews (60% in 1996 to less than 40% in 2003). In addition, there are a number of factors that are causing cost increases, including distributed generation, pensions, security, insurance and streetworks.

Increases in Capital Expenditure

2.8.8 Our previous consultation responses have highlighted the need to increase the level of allowed investment to secure the long-term safety, reliability and sustainability of the electricity infrastructure in this country. This position is supported by an independent report commissioned by the Energy Networks Association (ENA).

2.8.9 We note Ofgem's comments that it expects companies that propose a large increase in capital expenditure to put forward clear proposals with definable outputs and to point out how this will provide benefits to customers. Our plans for the period 2005 to 2010, as submitted to Ofgem in our Forecast Business Plan Questionnaires (FBPQs) are the next stage of our longer-term plans to maintain network performance, safety and reliability for our customers. These plans require the support and commitment of Ofgem over the period of the next three price controls.

2.8.10 We believe that our FBPQ submissions, consisting of clear proposals linked to definable outputs, together with the supporting narrative, make a conclusive case for a significant increase in capital investment.

2.8.11 Ofgem has defined the base case scenario for the FBPQ submissions as the minimum expenditure (operating and capital) necessary to run an efficient business while, for the period to 2020:

- maintaining existing underlying levels of Quality of Supply performance;
- maintaining existing underlying levels of fault rates;
- preventing a significant increase in the underlying sum of short interruptions and CIs; and
- maintaining underlying levels of network resilience.

2.8.12 However, historic levels of asset replacement expenditure will not be sufficient to meet these outputs. In responding with our investment plans, we have proposed an approach that halts the increasing fault rates in critical network assets, such as 11kV overhead lines in areas prone to severe weather and manually operated oil-filled switchgear. This approach manages the increasing problems of an ageing asset base.

2.8.13 Our leading class asset risk management systems indicate that a very large increase in capital investment would be required to hold fault rates constant on low criticality assets. In our view this is not required. Our approach is to manage the fault rates of these assets such that overall network performance is not jeopardised, therefore containing the necessary increase in investment levels.

2.8.14 In addition to the FBPQ Base Case submission, our DNO Alternative submission contains clear proposals and plans, with definable outputs, to provide an improvement in performance over the period to 2020. These plans reflect an improvement in performance consistent with our strategy, including achievement of the performance improvement targets specified by Ofgem and addressing other important issues such as the targeting of investment to improve the quality of supply experienced by 'worst- served' customers.

Treatment of Capex Under-Spends

2.8.15 In our view, the same incentives for capex efficiency should apply regardless of the size of the capital programme. However, we agree with Ofgem that the treatment of under-spends will require careful consideration at the next review particularly where large increases in capital expenditure have been allowed. The final proposals for the current review must set out clear rules on how under-spends will be evaluated at the next review.

Treatment of Capex Overspends

2.8.16 We welcome recognition that the allowed level of capital expenditure should not necessarily be seen as the maximum level of expenditure that a company can incur and confirmation that efficiently incurred additional investment will be included in the RAV. We would however reiterate our view that clear rules must be established for the tests that will be applied by Ofgem to determine whether such investment is efficient.

2.9 TREATMENT OF METERING

2.9.1 We continue to believe that a separate price control for metering is unnecessary and is not in customers' interests. However, given Ofgem's position that a separate price control will be introduced, we are committed to working with Ofgem to develop a suitable framework. Our comments on the issues raised in the consultation paper are set out below.

Stranding

2.9.2 We welcome Ofgem's offer to examine and seek solutions to concerns on stranding and note that a series of workshops has been set up to take this issue forward.

Duration of the Price Control

2.9.3 We note Ofgem's assumption that the metering price control will run for a five-year period subject to a Competitive Market Review (CMR). This CMR should be completed before a metering price control is introduced. We would add that Ofgem have not indicated whether they plan to undertake this review nationally or in each company area or, if price controls are removed, whether this would apply only to specific companies or for all.

Meter Asset Provision (MAP)

2.9.4 We support the proposed DRC (Depreciated Replacement Cost) methodology for MAP services, and can accept a price cap on a 'basic' domestic meter providing that stranding issues are adequately dealt with.

Meter Operation (Mop)

2.9.5 We support an average revenue cap for Mop services based on the volume of works undertaken, providing that our concerns regarding the stranding of fixed costs required to discharge our obligations are addressed.

Competitive Market Review (CMR)

2.9.6 Observation of the metering market indicates a significant degree of outsourcing both by distribution companies and suppliers. A number of major suppliers have either moved to non-DNO meter operators or are preparing to do so.

2.9.7 The CMR should be used to test the extent to which continued obligations on companies and a separate metering price control are likely to restrict entry into the meter operation sector or to reduce diversity and innovation in metering. Quantitative evidence on prices charged and market shares may be of limited value here, other than to underscore the diminishing role of distribution companies in the sector.

2.9.8 In our view, it is of greater importance to consider the extent to which suppliers and metering service providers are likely to respond to continued obligations on distribution companies in terms of the price, level and diversity of metering services offered or procured. In turn, the likely impact on distribution companies in terms of recovery of overheads in provision of a meter operation service where market share may be falling should also be taken into account.

2.10 DISTRIBUTION LOSSES

2.10.1 We await detail of Ofgem’s further thinking on distribution losses, which we understand is likely to be contained in the March paper. Further detail is required in this area to enable companies to develop loss reduction initiatives.

2.10.2 There are a number of significant gaps in the information currently available. In particular, there is no indication on how the proposed 'efficiency test' for loss reducing capital expenditure would operate, or on how this element would be distinguished from other capital expenditure. It is also unclear how the losses benchmark would be reset after the initial 5-year period.

SECTION 3 – QUALITY OF SERVICE AND OTHER OUTPUTS

3.1 GUARANTEED AND OVERALL STANDARDS OF PERFORMANCE (GOSP)

3.1.1 It is our view that GOSPs set extremely challenging targets and provide customers with effective protection. There are a number of important principles that must be recognised when considering changes to the current standards:

- the costs associated with meeting new or tightened standards must be appropriately funded;
- Overall Standards (OS) should not be set so tight so as to require networks to perform to a higher standard than required by the licence design standard P2/5;
- Guaranteed Standards (GS) should be seen as a means to compensate those customers who receive sub-optimal performance from time to time;
- the cost of GS payments that can be expected to be made by an efficient operator should be fully funded through the price control; and
- only repetitive GS failures for the same customers and not individual failures should be considered an indication of poor performance.

The issues raised in the consultation paper are dealt with in the following paragraphs.

Severe Weather Exemptions

3.1.2 Companies must remain exempt from the obligation to make GS payments during periods when they face exceptional levels of damage to their networks. The current interim arrangements should be extended to apply for the period of the next price control.

Protection Afforded to Large Business Customers

3.1.3 It should be made clear to customers that GS payments are not compensation for consequential loss as a result of loss of supply. While we agree with the principle that GS payments should be linked to the general use of system charges paid by customers, any customer seeking compensation for consequential loss should rely on insurance.

3.1.4 We believe that the GS regime should provide similar protection for all customers regardless of size and do not accept that the regime is currently biased towards smaller customers. The 'trigger period' for a GS payment for loss of supply to larger customer should not therefore be shorter than for other customers.

Scope of Exemptions

3.1.5 Our comments on exemptions for weather related events are provided above.

3.1.6 Contrary to Ofgem's view, industrial action by employees is not within a company's control. Accordingly, it is not appropriate to tighten or remove the exemption in this area.

Voltage Complaints

3.1.7 The specified timescale for investigating voltage complaints is already extremely onerous. It is therefore not appropriate to tighten this standard.

Removal of Overall Standards

3.1.8 We have previously pointed out the overlap between the existing Overall Standards and the measures incentivised under IIP. This results in a potential 'double jeopardy' from one incident. We therefore support the elimination of this overlap through removal of Overall Standards and the reporting of performance in the relevant areas under IIP.

Scope of Guaranteed Standards

3.1.9 As previously stated, Guaranteed Standards should be seen as a mechanism to provide compensation to customers who receive sub-optimal performance. We believe that these standards set extremely challenging targets and provide effective protection to customers. It is our view therefore that it is not appropriate to consider substantial revision or removal of these standards.

Priority Customers

3.1.10 We are committed to meeting the special needs of our priority customers and would be happy to work with Ofgem and the rest of the industry to further develop the services provided to such customers.

3.1.11 We note the suggestion that it might be appropriate to have shorter restoration targets for customers that require special medical equipment. We endeavour to reconnect customers that require special medical equipment as soon as possible after the occurrence of a fault and well before the GS trigger point. This action is not driven by GS targets but by a concern for the wellbeing of these customers. Therefore, we do not believe that it is appropriate to introduce a tighter GS target in this area.

3.2 REVIEWING IIP

3.2.1 Previous consultation responses have provided detailed comments on the scope of the output based incentive regime. In general, our views can be summarised as follows:

- the focus of improvements to the incentive framework must be on refining the operation of IIP (as applied to the existing output measures) rather than significantly extending the range of output measures;
- the scope of output measures should be based on measures required to protect customers' interests, informed by robust research into priorities and willingness to pay;
- the incentive mechanism needs to become more balanced, providing equal opportunities for rewards and penalties each year; and
- the costs of achieving any expected improvement in performance should be considered on a company specific basis, and would require full funding through an appropriate allowance.

Comments on the potential changes identified by Ofgem are provided in the following paragraphs.

Distinguishing Between Different Types of Customers

3.2.2 We do not believe that it is necessary or practical to report performance experienced by different groups of customers. We are not convinced of the potential benefits and believe that the costs of modifying existing IT systems (Troublecall, Prosper, connectivity models etc.) to provide this information would be prohibitive (of the order of several hundred thousand pounds).

Worst Served Customers

3.2.3 We support appropriate initiatives to improve the network performance experienced by 'worst-served' customers as companies should be funded and incentivised to target investment at such customers. Indeed, the DNO Alternative Scenario from our FBPQ submission makes provision for investment to be targeted reactively towards those customers who are consistently worst served over an extended period of time and proactively towards those communities who are most at risk of experiencing future multiple supply interruptions.

Disaggregated Data

3.2.4 We agree with Ofgem that disaggregated data should be provided on an annual basis as part of the IIP template.

3.3 FORM OF THE INCENTIVE FOR INTERRUPTIONS TO SUPPLY

3.3.1 We are pleased that Ofgem has recognised the problems with the form of the existing incentives under IIP. As previously stated, the focus for this price review should be on resolving these problems rather than extending the scope of output measures or increasing the financial exposure of companies.

Move to a Scheme with Rewards and Penalties in Each Year

3.3.2 The incentive mechanism should be symmetric, providing companies with equal opportunities for rewards and penalties in each year. However the resulting financial adjustments should be spread over a number of years to reduce year on year fluctuations in prices and revenues. This will result in a more balanced regime that should deliver benefits to both customers and companies.

Deadbands

3.3.3 The incentive scheme should be fully symmetrical with no, or very small, deadbands. We are concerned that significant deadbands would overly complicate the incentive regime and result in a non-linear relationship between performance and rewards/penalties.

Rolling Average Performance

3.3.4 It is most important to ensure consistency between the basis of target setting and the basis of performance assessment. This would imply that weather corrected performance (based on an objective assessment) should be used and that 10-year rolling averages are most appropriate for EHV and 132kV. At LV and HV there is much more consistency in underlying data and we are not convinced that rolling averages are required. If rolling averages are used then they should be based on 2 or 3 years at the most.

3.3.5 We do not accept that the assessment of performance on a rolling average basis would make it easier, or appropriate, to reduce the scope of any exemptions under the incentive scheme. Only underlying performance should be subject to the incentive due to the random nature of severe weather events and the significant impact that these events have on CI and CML performance.

Planned Interruptions

3.3.6 We believe that planned interruptions should be excluded from IIP to remove the perverse incentive to delay or curtail network investment because of the impact on IIP performance. If there is a concern that this would mean a ‘loosening’ of targets then the targets could be revised to exclude planned interruptions.

3.3.7 We are not convinced of the merits of allowing companies to roll-forward CI or CML associated with planned interruptions in 2004/05.

3.4 NETWORK RESILIENCE

3.4.1 Our response to the consultation paper of October 2003, identified four factors that determine network resilience:

- line construction;
- tree management;
- line maintenance; and
- response.

3.4.2 Our previous response further stated that network resilience can only be maintained and improved if all four of the factors listed above are adequately addressed and appropriately funded. Adequate, and in many cases, increased funding is therefore key to network resilience.

3.4.3 Due to the infrequency of such events and the unique circumstances surrounding each event, it is our strongly held view that it is not possible to define the statistical relationship between severe weather, faults and the number of customers interrupted. A benchmark approach to assessing network resilience is therefore not appropriate. It is our opinion that the various aspects of network resilience can only be measured after the occurrence of a real event. A post-event investigation should consider issues such as:

- CI/CML impact;
- response times;
- customer communication;
- weather severity and environmental conditions;
- line construction standards; and
- any other contributory factors such as availability of contracting staff, materials and specialist equipment.

3.5 INCENTIVES FOR TELEPHONE RESPONSE

3.5.1 We believe that the current Quality of Service and proposed Speed of Answering measures and incentives address the major aspects of this service. The focus should therefore be on improving the robustness and operation of the existing incentives rather than extending their scope.

3.5.2 As far as the Quality of Service incentive is concerned, we generally support the potential improvements suggested by Ofgem. In particular we support a move to address issues around survey bias and automated messaging by including all calls in the survey (including those that receive an automated message). We believe that the survey should continue to be based on relative performance.

3.5.3 As a general principle, any incentive should, where possible, be based on a measurable output and should not be based on a subjective assessment of performance. It is therefore entirely inappropriate to combine the Speed of Answering and Quality of Service incentives by the incorporation of a question on speed of answering.

3.5.4 Although there are some difficulties with comparison of performance between companies on Speed of Answering, we support the principles and objectives behind the recent changes to the Regulatory Instructions and Guidance (RIGs) to improve measurement of performance in this area. We expect these to provide statistics that, in time, will be more comparable between companies and can be used as the basis for an incentive. Rather than attempt to introduce a flawed incentive, it is our opinion that data on each company's performance should be collected over the duration of the next price control period and used to inform the formulation of an appropriate incentive from 2010 onwards.

3.6 ENVIRONMENTAL OUTPUTS

3.6.1 We are committed to our social and environmental responsibilities but do not support an extension to the scope of output measures to include performance in these areas. Performance in these areas is already reported to and monitored by a number of other regulatory bodies. We are therefore pleased that Ofgem does not intend to introduce financial incentives for environmental outputs. However, we continue to believe that the reporting of information on environmental performance to Ofgem would be duplication of effort. In addition, we are unclear as to what Ofgem would do with this information and what action might be taken by Ofgem if performance was deemed to be unsatisfactory.

SECTION 4 - DISTRIBUTED GENERATION

4.1 INCENTIVE FRAMEWORK FOR DISTRIBUTED GENERATION

4.1.1 Ofgem's current proposals are not acceptable to us due to the excessive and unmanageable financial risks that would be introduced. These proposals would, if implemented, be a major barrier to the connection of distributed generation in our licensed areas and to the achievement of Government targets.

4.1.2 Distributed Generation (DG) is a much more significant issue for our businesses than for most other distribution companies. According to the consolidated figures from the Distributed Generation Business Plan Questionnaires (DGBPQs) provided in Ofgem's October 2003 consultation paper, approximately 25% of the total anticipated volume of distributed generation will locate in our licensed areas.

4.1.3 The range of returns that would result for our businesses if Ofgem's current proposals were implemented are tabulated below. This shows that it is not possible for SP Manweb to achieve the regulated rate of return even if 100% of all anticipated generation were to go ahead. It also shows that there is significant risk that SP Distribution will earn less that regulated rate of return. Clearly this is not in line with Ofgem's stated principle that companies should not face excessive risks of returns below the allowed cost of capital on the overall DG investment.

	Option A (£2.5/kW, 70% pass-through)		Option B (£1.5/kW, 80% pass-through)	
	100% MW	50% MW	100% MW	50% MW
SPD	8%	5%	7%	5%
SPM	5%	3%	5%	4%

4.1.4 We agree with Ofgem's stated objectives in this area, namely to:

- encourage companies to undertake the investment required to facilitate distributed generation connections (and generally be proactive and positive in responding to connection requests); and
- encourage companies to invest efficiently and economically.

4.1.5 However, Ofgem's current proposals will not achieve these objectives. Rather, they will result in companies being forced to take a short-term and 'piecemeal' approach to accommodating DG and will result in:

- sub-optimal investment with connection and reinforcement costs being higher than necessary;
- some areas, such as mid-Wales, the Scottish borders and south-west Scotland, that are rich in renewable resources but require significant deep reinforcement, effectively being closed to generation due to the unacceptable low returns and financial risks that would result from the proposed hybrid mechanism;
- connections in other areas being delayed until sufficient volumes of generation are committed to allow the regulated rate of return to be achieved.

4.2 ALTERNATIVE APPROACH

4.2.1 The plans submitted in our Distributed Generation Business Plan Questionnaires (DGBPQs) can be split into two categories:

- key areas, rich in renewable resource, with a clear need for deep reinforcement in order to accommodate significant levels of anticipated generation; and
- areas forecast to have a relatively low generation impact, where it is anticipated that basic active management techniques or localised reinforcement can accommodate anticipated levels of generation.

4.2.2 We propose an approach that deals separately with each category and, in doing so, meets Ofgem's stated objectives and minimises the risks to both customers and companies. These proposals are summarised as follows:

- a programme of deep reinforcement, and the underlying assumptions in terms of the level of MW connectable, to be agreed in advance;
- the programme of investment to be secured in the RAV if delivered; and
- an amended hybrid mechanism to fund localised reinforcement.

Deep Reinforcement

4.2.3 We are pleased that Ofgem have acknowledged the need for deep reinforcement to take place ahead of DG development and realise the full potential of areas, such as ours, with high levels of natural resource. The investment plans presented in our DGBPQ submissions are based on a holistic view of network reinforcement requirements based on firm applications and enquiries from generators. This results in an overall solution that is most efficient, in terms of minimum medium/long-run costs, and most effective, in terms of available generation capacity.

4.2.4 As previously stated, Ofgem's current proposals would encourage a short-term and piecemeal approach to network reinforcement. That is, at any specific time, work would only take place in respect of those generation schemes that were committed. This would inevitably result in sub-optimal solutions and costs that are higher than necessary.

4.2.5 Under our proposed approach, companies would not receive revenue in respect of a particular reinforcement programme unless it was delivered. Allowed revenue would be calculated based on an agreed expenditure profile and any revenue received in respect of investment schemes that were not delivered would be 'clawed-back'. This would address Ofgem's stated concern that setting specific capital expenditure allowances for investment related to DG could expose customers to the risk that the investment was not undertaken.

4.2.6 Agreeing and reviewing the planning assumptions underlying the investment programme, in terms of MW of generation connectable in each area, would be in the interests of customers and companies. This would enable any significant changes, up or down, in the anticipated levels of generation to be reflected in amended investment plans and prices to customers.

4.2.7 Ofgem has expressed the view that the risk associated with a particular investment project should predominantly lie with those that are best able to manage them. However, it must be recognised when considering risk that distribution companies have very little influence over the level of DG connecting in their licensed area. For this reason, given the significant levels of deep reinforcement involved, a hybrid mechanism, even with an increased incentive rate, is not appropriate and will not deliver the necessary investment. This will effectively close areas to generation.

Hybrid Mechanism

4.2.8 We have a number of significant concerns with Ofgem's current proposals. However a hybrid approach could be acceptable to fund localised reinforcement if appropriate modifications are made:

- an increase in the pass-through component to provide a higher degree of down-side protection;
- the MW associated with specific generation schemes should be counted in the incentive mechanism as soon as a connection agreement is concluded and should remain for the assumed life of the assets; and
- the current obligation to offer terms for connection should be qualified to enable companies to delay connections until sufficient generation is committed.

Degree of Pass-Through

4.2.9 An increase in the pass-through element of the hybrid mechanism is required because, as previously stated, distribution companies have little influence over the level of DG that might connect. The levels of guaranteed return provided by the current proposals (of the order 1-3%) do not provide sufficient protection for companies. A level of pass-through of at least 90% is required. As stated in previous consultation responses, we understand that this would limit the premium return that could be earned. However we believe this to be entirely appropriate, as it is not in the interests of customers for companies to receive significant windfall gains from higher than anticipated levels of DG.

4.2.10 Companies should be given the choice of different levels of pass-through and associated incentive rate as it is not appropriate for companies to be forced to adopt a particular approach to risk and reward.

4.3 INCENTIVES FOR NETWORK ACCESS

4.3.1 It is our view that it is not appropriate to introduce an incentive scheme for network availability at this stage. Such a scheme should only be introduced once experience is gained of the operation of distribution networks with significant amounts of distributed generation.

4.3.2 Distribution networks have not been designed to provide 100% availability. Proper account must be taken of this fact when contemplating the introduction of an incentive regime for network availability. If it is decided that such a scheme is required for the next price control period then the only acceptable mechanism would be one where all generators pay some form of levy to fund the network unavailability payments made by the distribution company.

4.4 OPERATING AND MAINTENANCE COSTS

4.4.1 The expansion of our network to incorporate increased levels of generation will increase our requirement for operational expenditure in proportion to the increased capital expenditure. We have estimated this increase to be of the order of 2%. In addition, for the period 2005-2010, there will be a need for incremental operating expenditure to support the increased deployment of generation. These costs are derived from:

- increased operational complexity (removal of intertripping or voltage control schemes prior to switching);
- a need for more detailed analysis in advance of day to day operations;
- more in depth operational consideration of proposed connection arrangements and network modifications; and
- a need to monitor network performance following basic active management connections.

4.4.2 We do not agree that all of the increased operating costs associated with DG should be funded via the incentive mechanism, as companies will incur costs regardless of whether or not all of the anticipated generation is connected. Consideration must therefore be given to funding some of these costs in advance of connection.

4.5 INNOVATION FUNDING INCENTIVES (IFI)

R&D Expenditure

4.5.1 We support Ofgem’s stated objective for IFI funding as it is important that companies are enabled and encouraged to seek out new techniques and technologies. We believe that increased levels of R&D expenditure, driven by IFI incentives, will deliver benefits to customers that are not available via current regulatory incentives.

4.5.2 The December consultation paper comments on the relatively low figure for R&D Intensity (R&D expenditure expressed as a percentage of turnover) in the distribution sector compared to the UK average. This is a symptom of the pressures imposed by the regulatory regime and, in particular, the frontier approach to funding operating expenditure.

4.5.3 We have developed and maintained constructive relationships with a number of research establishments. Although our direct cash input to R&D activities has been limited by regulatory pressure to reduce operational expenditure, we have endeavoured to compensate for this by providing ‘in kind’ support. This has included allocating time from key staff for direct involvement in projects, providing comment and direction to researchers, giving access to technical data and systems and carrying out field trials.

4.5.4 Our Distributed Generation Business Plan Questionnaire (DGBPQ) submissions highlight the need for a continued and appropriate focus on developing and deploying innovative techniques for connecting generators and managing their impact on the network. Subject to the outcome of the current consultation process, we would propose to increase current levels of direct spending and increase our commitments via indirect spending (through manpower and information provision) through the next Price Control period. Projects that we intend to pursue include Power Flow Control, Alleviation of Reverse Power Restrictions and Introduction of Active Management.

Encouraging Efficient Use of IFI Funding

4.5.5 We note Ofgem’s thoughts on how best to encourage efficient use of IFI funding and are generally in agreement with the principle of open reporting and selective auditing of IFI projects.

Proportion of Pass-Through

4.5.6 We continue to believe that the proportion of pass-through of IFI funding should be at least 90% for the duration of the next price-control period. A reduced level of pass-through would not provide companies with sufficient certainty of cost-recovery.

Good Management Practice

4.5.7 We agree that it is not appropriate to attempt to force a particular management process on R&D as this could stifle innovation. This should be left to individual companies to develop in line with their own requirements.

Intellectual Property Rights (IPR)

4.5.8 We welcome Ofgem's decision not to attempt to impose rules regarding the management of IPR.

4.6 REGISTERED POWER ZONES

4.6.1 We support Ofgem's stated objectives for RPZs. As previously stated, it is important that companies are enabled and encouraged to seek out new techniques and technologies where they are appropriate and provide benefits to customers.

Granting RPZ Status

4.6.2 While we see merit in the appointment of an independent panel to advise Ofgem it is most important that clear criteria be established for RPZ approval. In our opinion decisions on RPZs should be driven by effectiveness in terms of the amount of generation that could accommodated and the potential cost savings that might result.

Incentive Level

4.6.3 We have already stated our significant concerns on the current proposals for a hybrid incentive mechanism. Assuming that a satisfactory mechanism is introduced then we agree that it is generally appropriate for the RPZ incentive rate to be up to twice the 'normal' incentive rate for a period of 5 years.

Failure of RPZs

4.6.4 A fundamental question arises on how failures of RPZs will be treated. While it should not be expected that rewards would accompany failed projects, RPZ incentives would be weakened significantly if there were no mechanism for funding a 'traditional' solution in the event of the RPZ solution being unsuccessful.

4.7 REGULATORY IMPACT ASSESSMENT

4.7.1 Our comments on the issues raised by Ofgem's draft Regulatory Impact Assessment (RIA) on distributed generation are included in Appendix 1 of this document.

SECTION 5 - ASSESSING COSTS

5.1 OVERALL APPROACH

5.1.1 As set out in previous consultation responses, we are generally supportive of the principles of the approach outlined by Ofgem for assessing costs but, based on our experience during the last review, have some concerns about the application of these principles. We would reiterate the importance of transparency of outcome. A clear audit trail must be provided to enable each company to clearly understand Ofgem's analysis.

5.2 PUBLICATION OF DATA

5.2.1 We fully support the publication of appropriate data to inform the price review process. However, we would add that data should only be published if it is relevant, accurate, comparable and complete. The publication of any data that does not pass these tests will not assist with a transparent price review process and could result in major stakeholders, including city analysts and major investors, drawing erroneous conclusions.

5.2.2 In addition, the commercial interests of companies must not be adversely impacted by the publication of detailed data on costs and expenditure. If such data were to be available to suppliers of goods and services then it could seriously prejudice our ability to procure these goods and services at competitive rates. Furthermore, detail on expenditure in competitive areas must not be published as this could seriously and prejudicially impact our ability to compete in these areas.

5.3 COST NORMALISATION

5.3.1 We agree with Ofgem that comparison and assessment of the relative performance of companies depends on the quality of the data used. It should be emphasised however, that if cost data cannot be adequately normalised, then the basis for relative comparison would be undermined and less weight should be given to the results.

5.3.2 We are concerned that removal of atypical costs would lead to an unsustainable cost benchmark. For example, costs relating to storm damage do not occur every year but do occur from time to time. It is important that Ofgem's methodology ensures that these costs are adequately funded.

5.4 BOTTOM-UP MODELLING

5.4.1 Particular care must be exercised when undertaking bottom-up modelling. Companies do not generally have common cost allocation procedures and, consequently, unit costs for individual activities will not be directly comparable. In addition, difficulties will arise as a result of different organisational structures and varying degrees of outsourcing. In our view, the most pragmatic and effective approach to these issues is to focus on 'fully absorbed' costs (i.e. inclusive of all allocated overheads) at an aggregated level rather than on an excessively detailed analysis of the overhead pool of each company.

5.4.2 Our primary concern with an excessively detailed approach is that it could lead to the setting of a lowest cost benchmark for each activity or cost category. This could result in an overall benchmark that is below that attained by any one company and is effectively unattainable. In addition, we are concerned that an excessively detailed approach will be data and resource intensive.

5.4.3 It must be recognised when carrying out bottom-up analysis that simplistic ratios, such as unit costs, are potentially misleading as they do not take into account regional and other factors inherent to companies and their licensed areas. Unit capital costs per item of equipment are also potentially misleading as an efficient company must consider lifetime costs and a complete cost-benefit analysis, including quality and environmental factors. For example, the cheapest transformers are likely to have the highest energy losses.

5.4.4 Similarly, fault repair costs and maintenance costs may be reduced by lowering the quality of supply, contrary to the interests of customers. There have been some indications that certain companies may have cut costs at the expense of customer service. Ofgem would not be protecting customers' interests by forcing other companies to sacrifice quality in an attempt to meet lowest cost.

5.5 TOP-DOWN MODELLING

5.5.1 As stated in previous consultation responses, the strict use of frontier benchmarks would result in an over-estimation of the potential for cost-reductions because of data consistency problems and comparability issues between companies. An average benchmark is more appropriate as it can be estimated with more certainty. However it should be noted that any estimate of relative efficiency will contain significant statistical noise. The weighting given by Ofgem to such estimates must take proper account of this.

5.5.2 The use of a frontier benchmark would be inconsistent with standard approaches to estimating the cost of capital. The risk adjusted market rate of return relates to average performance. In competitive industries, companies on or near the efficiency frontier earn above average rates of return.

5.5.3 We note the factors that Ofgem will consider in determining the most appropriate benchmark for use in comparative analysis and discuss these below.

Robustness

5.5.4 As previously stated an average benchmark can be estimated with more certainty than a frontier benchmark and is likely to be less sensitive to different assumptions and the position of outlier companies. It can therefore be said that an average benchmark is likely to be more robust.

Sustainability of Efficiency Targets

5.5.5 Again as previously stated, the strict use of frontier benchmarks will tend to over-estimate the potential for cost-reductions. An average benchmark is therefore likely to set more sustainable efficiency targets than a frontier benchmark.

The Impact on Incentives to Improve Efficiency

5.5.6 An average benchmark will provide incentives for all companies to improve efficiency including the most efficient companies. We note with interest that Ofgem intends to consider the position of the British distribution companies in relation to the 'true' efficiency frontier in electricity distribution. Given the recognised difficulties of using international data we would welcome confirmation from Ofgem on how it intends to establish the 'true' frontier, what data-sets will be used and the normalisation adjustments that will be applied.

The Impact of the Efficiency Targets on the Overall Incentive Framework

5.5.7 We believe that this factor is closely related to the sustainability of the efficiency targets and the need for companies to be given appropriate funding to meet their required outputs. Given that a frontier approach can over-estimate the scope for cost-reductions, there is a risk that it will not provide sufficient funding for companies and will therefore undermine the overall incentive framework.

5.6 TOTAL COST MODELLING

5.6.1 As stated in previous consultation responses, we support the use of total cost modelling to complement separate analysis of capital and operating expenditure. However, assessment of total cost is not straightforward. A number of issues are discussed in the following paragraphs.

The Definition of Capital

5.6.2 The most significant issue for total cost analysis is the definition of capital. The main alternatives are:

- regulatory depreciation plus return;
- the use of historic data to reconstruct more comparable figures from historic additions to fixed assets, using an appropriate price index and a common depreciation methodology;
- the use of MEA values; and
- capital expenditure in current or average years.

5.6.3 The most appropriate methods would appear to be the use of regulatory depreciation plus return or the use of historic data, an appropriate price index and a common depreciation methodology. However, it should be noted that neither of these methods is without its drawbacks. If regulatory depreciation plus return is to be used then the varying market to book discounts at flotation, particularly between England and Wales and Scotland, and the differences in depreciation rates would need to be satisfactorily addressed. The use of historic data is the most data intensive but is, in theory, the most accurate. However the efficiency scores of individual companies will be affected by their inherited asset base or by historic trends. These are factors over which the current owners of the company could have had no control.

5.6.4 MEA values are much larger than regulatory asset values and would dominate any other expenditure. For this reason we do not believe that MEA should be used. The use of capital expenditure in the current year or over the period of the current price control will be highly sensitive to a company's position in the investment cycle and is therefore unlikely to be appropriate. For this reason we do not believe that current capex should be used.

Cost Drivers

5.6.5 The identification of an appropriate cost driver (or cost drivers) will require careful consideration. It should not be assumed that the composite scale variable used at the last price review is appropriate. Measures relevant to assets, such as age and performance, will need to be considered when assessing the most appropriate cost drivers.

5.7 QUALITY

5.7.1 Measures of quality should be included when modelling the efficiency of distribution companies. Costs are clearly affected by the quality of service provided and any model that ignores quality would not be appropriate. The most important aspects of quality are the number and duration of interruptions to supply.

5.8 CEPA'S STUDY OF TOTAL FACTOR PRODUCTIVITY

5.8.1 We believe that the CEPA study significantly over-estimates the scope for further productivity improvements. As stated in previous consultation responses, there is considerable doubt as to the robustness of TFP studies. Past performance trends will not provide a good indicator of the future because of the significant gains that have been achieved in the period since privatisation.

5.8.2 In addition, it is not appropriate for price controls to make assumptions about the efficiency and productivity gains that can be achieved as this weakens the incentives for companies to deliver such gains.

5.8.3 Total factor productivity (TFP) studies for the US, Canada and New Zealand (detailed references are provided in Appendix 2 of this response document) have estimated improvements in TFP of approximately 1% per annum for electricity distribution businesses. These would result in very small positive X factors, after deducting TFP growth for the economy as a whole.

5.8.4 Detailed comments on the CEPA report are provided in Appendix 2 of this response document. Our main comment is that the figures presented in the report are biased upwards (i.e. the paper over-estimates the scope for future productivity improvement) as a result of a number of factors, including:

- the inclusion of the transfer of costs from Distribution into Supply following DPCR3 as an efficiency gain;
- the implicit projected continuation of the one-off ‘privatisation effect’;
- a non-standard approach to the determination of input and output weights;
- the reliance on current cost accounts which is likely to understate the growth in the capital stock and overestimate the growth in TFP;
- the fixing of the share weight assigned to each input and output; and
- undue reliance on short periods of time.

5.9 INTERNATIONAL DATA

5.9.1 The use of international benchmarking data is, in theory, attractive. International data can provide a larger data set that could be used to:

- identify relevant cost drivers;
- estimate functional form;
- derive weights for calculating compound variables (e.g. scale and quality measures); and
- test restrictions imposed on parameters (e.g. intercept and returns to scale) or functional form.

5.9.2 However, it will be extremely difficult in practice, to make meaningful comparisons with international data due to differences in a number of fundamental areas, including:

- taxation;
- exchange rates and/or purchasing power parity;
- wage rates;
- accounting conventions;
- planning standards;
- network architecture and distribution voltage levels; and
- quality of supply.

5.9.3 In addition it will be difficult to obtain suitably robust data for benchmarking purposes. In particular, data collated from published statutory accounts will not be suitable.

5.10 PANEL DATA

5.10.1 The use of panel data techniques would potentially enhance the analysis provided that the additional years of data are strictly comparable.

5.11 TREATMENT OF MERGERS

5.11.1 We note that Ofgem is reconsidering its policy on the treatment of mergers and, in particular:

- the treatment of mergers that occurred before June 2002; and
- whether or not it is reasonable to expect all merged entities to be on the efficiency frontier.

5.11.2 The following principles should be applied to the treatment of mergers:

- all mergers should be treated on a consistent basis;
- merger savings must be treated like any other efficiency saving and captured via comparative analysis; and
- it is not valid to assume that merged companies will be on the efficiency frontier as there are now more merged companies than non-merged companies.

5.11.3 We would point out that Ofgem's previous policy of reducing revenues by £12.5m has only been applied to ScottishPower/Manweb. There must be no further revenue reductions applied in respect of this transaction as merger savings will be captured by comparative analysis. In addition, by the end of this price-control period we will have paid more than any other merged entity. Consistency of approach will require that that we be allowed to recover the excess payment during the next price control period.

5.12 OFGEM'S APPROACH TO ROLL-FORWARD OF THE RAV

5.12.1 We agree with Ofgem that definitions of expenditure need to be agreed and clearly communicated and documented. We also agree entirely with the principle that customers should not pay twice for particular items of expenditure. However we would add that companies must be adequately funded for properly incurred expenditure.

5.12.2 We are concerned that Ofgem's proposed treatment of fault expenditure does not recognise the difference between fault repair and the replacement of assets as a result of faults. The December paper classifies the total cost of these separate categories of work as 'fault-costs' and makes the assertion that all such expenditure was funded as operational expenditure at DPCR3.

5.12.3 Our position is as follows:

- we have always accounted for fault repair costs as operational expenditure and for post-fault replacement costs as capital expenditure; and
- the cost of post-fault asset replacement must, like all other capital expenditure, be added to the RAV.

5.12.4 We have responded separately to Ofgem's specific request for a convincing rationale and evidence to support this position. We expect Ofgem to provide documentary evidence to support any position to the contrary.

5.12.5 Analysis of the information on 'fault costs' presented in the December consultation paper shows a wide variance in reported costs. This highlights the fact that there is no consistent treatment across companies and, in our opinion, indicates that all such expenditure could not have been funded as operating expenditure.

5.12.6 It has become apparent since DPCR3 that definitions of expenditure categories were very unclear and there were a variety of interpretations of PKF's intentions concerning the treatment of fault costs. At no time did PKF state that their intention was to transfer all fault related costs from capital expenditure into operating expenditure and the information provided to PKF was not sufficient to enable such a transfer to be made. We provided accurate data to PKF in good faith that related to a specific question on *changes* in capitalisation policy, and PKFs adjustments were made on this basis.

SECTION 6 - FINANCIAL ISSUES

6.1 FINANCIAL RING FENCE

6.1.1 We agree with Ofgem that there is no need to strengthen the provisions on financial ring-fencing that currently apply to licensees but note that consideration is being given to the codification of a formal 'cash lock up mechanism' to be applied under specific circumstances. As stated in previous consultation responses, we believe that current licence provisions are adequate and that no licence changes are required.

6.2 COST OF CAPITAL

6.2.1 It is important when considering the cost of capital to recognise the need to provide a sufficient and stable return to attract and retain funding from capital markets. Flexible and efficient access to capital markets is vital to enable companies to invest and deliver networks that meet the demands of future generators and consumers.

6.2.2 An increased cost of capital of between 7-8% (pre-tax real) is strongly supported by market evidence and authoritative academic studies.

6.2.3 There are a number of key uncertainties surrounding this review, and future investment incentives would be undermined by a cost of capital that is set 'too low'. This would have serious implications for the long-term sustainability of the electricity infrastructure and the achievement of Government targets for renewable generation.

General Method

6.2.4 As stated in previous consultation responses, we agree with the continued use of the Capital Asset Pricing Model (CAPM) and are in general agreement with the proposal of adopting a forward looking approach coupled with a longer-term view of the overall return on equity. It should be noted however that CAPM ignores the negative 'skewing' of rate of return caused by incentive regimes such as IIP. Academic research suggests that the traditional CAPM under-estimates the required rate of return because such 'skewness' is not taken into account. It is therefore important that the allowed return is set towards the upper-end of the range, rather than simply at the mid-point, to allow for this under-estimate.

6.2.5 There is considerable regulatory precedence for using the Dividend Growth Model (DGM) as a check on the results of the CAPM. Recent academic research shows that the cost of equity estimates using DGM are at the higher end of the range identified by CAPM for the distribution companies, even when a beta value of 1 is used.

Cost of Historic Debt

6.2.6 We agree with Ofgem that the allowed cost of debt should be based on an efficiently financed company that takes a balanced approach to the management of its borrowings, that diversifies its risks cost-effectively and aims at achieving a broadly stable real interest cost over time. However this is not consistent with Ofgem's apparent reluctance to take account of the cost of historic debt.

6.2.7 An efficiently financed company will have raised debt over a long period in the past, arriving at a relatively stable real interest cost over time. This will not be the same as the current cost of debt as determined by forward looking data since it is more likely to be the average of historic rates over a period of, say, 10 years. We would therefore reiterate our view that the allowed cost of debt must take account of efficiently incurred historical debt.

Treatment of Tax

6.2.8 We remain concerned about any proposal to a move to a post-tax cost of capital or to use company specific allowances for tax liabilities. Such an approach would encourage and reward a short-term approach and destroy medium to long-term incentives for tax efficiency. This would have adverse consequences for all stakeholders, including customers.

6.2.9 Ofgem must retain a pre-tax approach to cost of capital with the tax allowance set at an appropriate level based on the average industry position. This approach provides the strongest incentive for companies to maintain tax liabilities at an appropriate and stable level over the medium to long-term.

6.2.10 It is not clear from the consultation document what is meant by a post-tax approach. Ofgem should confirm the exact approach that is being suggested (i.e. post-tax debt, post-tax equity or pre-tax debt, post-tax equity). Whatever the exact method adopted we are concerned that it will be extremely complex and will create more problems than it solves.

Assumptions on Gearing

6.2.11 The level of gearing assumed when setting the cost of capital should be the same for all companies as Ofgem have previously set out in the initial conclusions to the Consultation on Monopoly Price Controls.

6.2.12 We are very concerned at any suggestion that the level of gearing assumed in setting the cost of capital should be increased. This would very likely lead to an increase in the levels of debt across the industry.

6.2.13 Distribution companies must be able to attract and retain equity funding for their capital investment programmes. All other factors being constant, an increase in the level of gearing assumed in setting the cost of capital will effectively reduce the cost of capital allowed at a time when significant increases in investment are required.

6.2.14 As previously stated, future investment incentives would be undermined by a cost of capital that is set ‘too low’ with serious implications for the long-term sustainability of the electricity infrastructure and the achievement of Government targets on renewable generation.

Upstream Debt

6.2.15 The level of upstream debt guaranteed by the assets of distribution companies is not relevant when considering the actual level of gearing. In the case of guarantees supported by the assets of SP Distribution, extremely tight restrictions are placed on the beneficiary of these guarantees under the annex to the consent issued under Standard Licence Condition 47 (Indebtedness). These restrictions include a cap on indebtedness, restriction on business diversification and an obligation to maintain a credit rating of no lower than BBB from S&P or Baa2 from Moody’s. Moreover, SP Distribution is required to be counter indemnified by a company of substance and is supported in its role as guarantor, jointly and severally, by SP Transmission and by SP Generation. It is misleading to refer to levels of gearing, including upstream debt, without reference to these restrictions and it would be wrong to use such a gearing level in calculating the cost of capital.

6.3 FINANCIAL MODELLING & FINANCIAL INDICATORS

6.3.1 We welcome the transparent approach that has been adopted by Ofgem in the development of its financial model and will be working with Ofgem and other industry participants on its further development.

6.3.2 We note the financial indicators that Ofgem intends to use and are in general agreement with this approach.

6.4 PENSION COSTS

6.4.1 As stated in previous consultation responses, we welcome Ofgem's recognition of this important issue and will continue to work constructively with Ofgem to ensure that a satisfactory resolution is achieved.

Over or Under Provision

6.4.2 Of the options set out by Ofgem, the most equitable and pragmatic will be to assume that the allowance for each company in DPCR3 was equal to the contribution actually made. While we accept Ofgem's point that this might appear to be inequitable to some companies, given the uncertainty around the level of allowances, this is the most equitable option for all companies.

6.4.3 It is our view that this rule should only be applied to DPCR3. To attempt to apply this rule to periods before DPCR3 would significantly increase the complexity of the exercise and the degree of retrospection required.

Early Retirement Deficiency Costs

6.4.4 As previously stated, the provision of enhanced benefits under severance arrangements has resulted in direct savings to customers. While we welcome confirmation that Ofgem will take account of redundancies occurring prior to March 2003 when applying its guidelines, we would reiterate that the costs, past and future, associated with the provision of these benefits must be treated as a legitimate business cost.

6.4.5 A balanced approach is required that recognises the benefits that have been delivered to both customers and shareholders from the use of surpluses to fund severance programmes. We do not accept Ofgem's view that, since there was no explicit commitment that such costs could be recovered from customers, these costs should not be recoverable. It can equally be argued that the funding of such costs from surplus is entirely legitimate and Ofgem have never given any indication that these costs could not be recovered.

APPENDIX 1 – DEVELOPING THE REGULATORY IMPACT ASSESSMENT (RIA) FOR DISTRIBUTED GENERATION, IFI AND RPZs

Our previous consultation responses have welcomed Ofgem's inclusion of an initial Regulatory Impact Assessment (RIA) for DG. We agree that it is important to identify and, where possible, quantify the costs and benefits of Ofgem's proposals.

We have endeavoured to provide answers to the questions posed in the draft RIA. However, due to the complexity of the issues involved and the limited time available to provide a response to this consultation document, we have not yet been able to quantify our answers. We consider that the most effective means of quantifying the various costs and benefits will be via some form of working group comprised of representatives from the various impacted bodies. We would be happy to participate in such a group.

Our comments on the questions posed in the draft RIA are provided in the following paragraphs.

What would be the impact of the distributed generation incentive, the IFI and the RPZ mechanism on the volume (or capacity) of distributed generation connecting to the distribution networks?

DG Incentive

As set out in Section 4 of this response document we are concerned that Ofgem's current proposals would, if implemented, effectively 'close' to DG a number of areas that are rich in renewable resource. We estimate that around 1200 MW of generation could locate in these areas if a satisfactory mechanism is put in place to fund deep reinforcement.

Innnovation Funding Incentive

IFI should increase the overall level of generation connected to the networks by leading to lower cost connection methods and methods of network operation. This would result in lower charges for generators.

Registered Power Zones

RPZ should have a small positive impact on the level of generation connections as small niche schemes that previously may not have been viable could be enabled. The effect should be shorter term than the effect of the IFI although the scale of is likely to be more significant.

What would be the expected costs of the incentive framework to distributed generators for connecting to the networks? What benefits would it provide?

The main cost elements are those associated with reinforcing and transforming networks to facilitate DG. These costs have been quantified for the period of the next price control in each company's Distributed Generation Business Plan Questionnaire (DGBPQ).

If the current proposals are implemented then companies such as ours will be forced to take a short-term and sub-optimal approach to network investment to accommodate DG. This is likely to result in higher that necessary shallow connection costs and, potentially, higher total costs. In addition, it is likely to result in a reduction in the number of connections and to act as a significant barrier to the achievement of Government targets for renewable generation.

The main benefit of a successful mechanism would be the achievement of Government targets.

What would be the impact of IFI and RPZs on research and development and network innovation? What benefits would these provide to generators and other connected customers in comparison to the associated costs that would be incurred?

R&D and innovation would benefit from IFI and RPZ because of the increased exposure and clear funding for these activities. The 'use it or lose it' element of IFI is particularly useful. The expected benefits will be more efficient network management (especially if combined with appropriate increases in base line capacity in remote areas of network) and lower connection costs.

What would be the impact of each of the proposed incentive schemes on the costs of connecting distributed generation in the period to 2010 and in the longer term – both in terms of £/kW and total system costs?

Under the current proposals, there will be little or no deep reinforcement undertaken in our licensed areas in anticipation of generation connections due to the excessive risk of returns below the allowed cost of capital. The only reinforcements undertaken would be those that follow a signed connection agreement. The overall £/kW would probably increase from that specified in our DGBPQs, with the shallow element being the most significant. Over the long run, total system costs would be higher than could be achieved by advanced reinforcement in areas rich in renewable resource.

How would you expect new technological developments to reduce the £/kW cost of connecting distributed generation over the period to 2010?

New technology would help to minimise shallow costs through combining generation output parameters with real time network parameters. Deeper reinforcement costs could also be reduced, particularly if introduced in tandem with increasing baseline capacity in popular areas, allowing fundamentally different management to be introduced.

To what extent does the connection of distributed generation require new R&D by distribution companies?

All generation could be connected by traditional solutions if required. However, as previously mentioned, R&D could help to reduce connection and network management costs.

What would be required to do in order to administer each of the proposed incentive schemes and what would be each of the associated costs?

For the DG incentive it would be necessary to register all schemes connected together with the amount of reinforcement required and the associated MW of generation. Set-up and ongoing administration costs, including IT and staffing costs, would be incurred however further work is required to quantify these costs.

For IFI and RPZ there would be set-up and ongoing administration costs associated with the recording, reporting and auditing of schemes. As with the DG incentive scheme, further work is required to quantify these costs.

What would be the impact of changes in the volume of distributed generation on quality/security of electricity supply and losses? Will distributed generation provide benefits in these areas, and, if so, can they be quantified?

As set out in our Forecast Business Plan Questionnaire (FBPQ) Scenarios and Sensitivities submission, the DG investment case has been formulated to enable the connection of DG without compromising the economic and efficient development of the network. Since the works required for DG are mainly proposed at 33kV and at the transmission / distribution boundary, it is believed that there is little scope for spin off benefits.

It is estimated that there will be a marginal improvement in resilience, through the upgrade of 120km of 33kV lines. The impact the DG Scenario will have on CI and CML performance will depend on the interaction of two opposing factors:

- by reinforcing the network in windy areas there would be an improvement in the level of weather related faults; however
- as these new lines are adding network length in severe weather areas it might be anticipated that the total level of CIs would increase.

In practical terms, these two factors will cancel each other out. It is therefore considered appropriate to assume that new infrastructure provided for DG has no impact on quality of supply.

We anticipate that increased levels of DG will potentially increase losses close to the point of connection with, possibly, a corresponding reduction in losses at higher voltages. However, further experience of the operation of networks with large volumes of DG is required before the impact on losses can be properly assessed and quantified.

How much of the increased volume in distributed generation would be of environmentally friendly types (e.g. renewables)? By how much would this be expected to replace electricity from non-renewable sources? Would such generation contribute to the reduction in emission levels and, if so, how should these benefits be quantified?

All of the generation that we anticipate will be connected in our area should be eligible for Renewables Obligation Certificates (ROCs). We are not in a position to comment on how much this can be anticipated to replace electricity from non-renewable sources or on the reduction in emissions levels that might result.

DISTRIBUTIONAL EFFECTS

We are in general agreement with the principle that costs should be borne by those that incur them but welcome recognition that exceptions may arise if investment is incurred and distributed generation does not materialise or subsequently disconnects.

In our view, it is likely that demand customers will have to bear some of the costs associated with distributed generation at least for the duration of the next price control period as levels of distributed generation increase.

Would there be significant costs outstanding if expansion of the network was not taken up by distributed generators? Could the additional capacity be utilised in another way, and if so, how should any costs be treated?

Significant costs, associated with shared and strategic assets (quantified in DGBPQs) will be outstanding if expected generation does not go ahead although deep reinforcement in some areas could provide benefits to demand customers. Options for recovering stranded costs include via the general customer base (preferably across GB) or from central Government (possibly from the ROC buyout).

Are the IFI and RPZs likely to provide benefits to all consumers connected to the network, and if so, how would these compare to the benefits realised by distributed generators and distribution companies?

It is anticipated that DG will be the first beneficiary of IFIs but it would be expected that in the long run all connectees would benefit equally. Only DG is likely to benefit from RPZs.

The Incentive Framework for distributed generation assumes an asset life of 15 years for infrastructure assets required for connecting distributed generation. Is this appropriate and how does it compare to the assumed life for other network assets?

A 15-year depreciation period seems sensible for connection assets and shared assets associated with specific schemes. It would seem logical for deep reinforcement assets to have the same regulatory asset lives as other network assets.

RISKS AND UNINTENDED CONSEQUENCES

Uncertainty and cost under-recovery from the perspective of the distribution company are the main issues that could raise potential risks to the success of the policy in meeting its objectives. As previously set out, we consider that the current proposals for the DG incentive will be a major barrier to the achievement of the policy objectives.

COMPETITION

We agree with Ofgem that an increased volume of distributed generation will have a positive effect on the general level of competition in the generation sector. This positive effect will be maximised by the timely provision of networks in high resource areas.

REVIEW AND COMPLIANCE

Our comments on the likely costs of reviewing and monitoring the proposed arrangements are provided above in response to the question on likely administration costs.

APPENDIX 2 – RESPONSE TO CEPA PAPER ON TOTAL FACTOR PRODUCTIVITY

We have a number of concerns with the use of the results of any study of Total Factor Productivity (TFP) to set revenue allowances. In addition, we have a number of specific concerns with the CEPA analysis and the associated report. Our concerns can be summarised as follows:

- it is not appropriate for price controls to make assumptions about efficiency and productivity gains, over and above the DPCR4 benchmark, that may be achieved in future, as this considerably undermines incentives for efficiency;
- while estimates of TFP can be used as a basis for the derivation of X factors for use in a price control formula, great care must be taken in the application of the results of any such study; and
- the CEPA study significantly over-estimates the potential for TFP growth.

These issues are dealt with in more detail in the following paragraphs.

EFFICIENCY INCENTIVES

We are extremely concerned at the suggestion in Section 2.3 of the CEPA report that the estimated TFP trend can be used as a lower bound or as a projection of efficiency improvement for companies on the efficiency frontier. There is no basis on which to project the shift in the frontier as there is no history of observed shifts in the frontier. In addition, there is no theoretical basis from which to project separate frontier shift and catch-up components.

In any case, it is not appropriate for Ofgem to anticipate potential future out-performance of the cost benchmark that will be established during DPCR4. The scope for future out-performance is required to ensure that the incentives for efficiency improvements operate properly. The expenditure incentive mechanisms operate by passing through efficiency gains after a pre-determined time lag. Incentives for efficiency will be significantly undermined and weakened if future efficiency gains are anticipated by further reducing the DPCR4 benchmark by the historic trend in cost reduction.

USE OF TFP STUDIES TO SET X FACTOR

Great care must be taken in the application of the results of any TFP study to derive an appropriate X factor to use in a price control formula. X should be set as the differential between the projected industry TFP growth and that for the whole economy. In this situation, if a company were to out-perform the projected industry TFP growth then it would earn an above average rate of return. This is consistent with what would happen in a competitive market.

A TFP improvement that is derived from industry data should be applied to the average company, not to the frontier. The historic improvement in industry TFP includes the catch-up of less efficient firms (as well as the one off privatisation effect for regulated utilities). To apply a TFP improvement that includes this catch-up component to the frontier would overstate the potential for improvement in the frontier and would be inconsistent with what would happen in a competitive market.

CEPA'S ESTIMATE OF TFP GROWTH

Total factor productivity (TFP) studies for the US [1,2], Canada[3] and New Zealand[4] have estimated improvements in TFP of approximately 1% per annum for electricity distribution businesses. These would result in very small positive X factors, after deducting TFP growth for the economy as a whole. These other studies indicate that the figures presented in CEPA's study are biased upwards. This results from a number of deficiencies with CEPA's study. These are discussed in the following paragraphs.

[1] Kaufman, L and Lowry, MN (1999) Price Cap Regulation of Power Distribution, Report prepared for Edison Electric Institute by Pacific Economics Group, Madison

[2] Makholm, JD and Quinn, MJ (1997) Price Cap Plans for Distribution Companies Using TFP Analysis, NERA Working Paper, Cambridge, Massachusetts, October

[3] Cronin, FJ, King M and Colleran M (1999) Productivity and Price Performance for Electric Distributors in Ontario, Report prepared for Ontario Energy Board Staff by PHB Hagler Bailly Consulting, Toronto

[4] Meyrick and Associates (2003) Regulation of Electricity Lines Businesses, Analysis of Lines Business Performance 1996-2003, Report prepared for Commerce Commission, Wellington, New Zealand, December

1) Including costs transferred from Distribution into Supply at the last price review as an efficiency gain.

CEPA's analysis includes the costs that were transferred from distribution to supply following the last price control review as an efficiency gain. This transfer of costs amounted to over 18% of the total unadjusted controllable costs and its inclusion in the estimate of the trend of TFP is not appropriate and clearly biases the estimate upwards. The CEPA report recognises that the estimate of the trend in TFP for distribution companies would be 1.1% lower if these cost reductions were not included as efficiency gains.

2) Implicitly projecting continuation of the one-off 'privatisation effect'.

It is widely acknowledged that a one-off 'privatisation effect' led to an improvement in the TFP of utilities following the change from a nationalised industry to regulated investor-owned companies. However, CEPA have made no attempt to separately identify the component of TFP improvement since privatisation that is due to this effect.

Consequently, CEPA implicitly project a continuation of the privatisation effect into the future. This is not appropriate and has the effect of over-stating the potential for productivity improvement.

3) No account is taken of risk substitution.

Estimates of TFP improvement derived from expenditure data need to be adjusted for 'risk substitution'. That is, the amount of risk borne by companies has changed at a different rate than the volume of inputs.

Since privatisation, distribution businesses have chosen to bear more risk by reducing expenditure. This substitution of risk bearing for other factors of production should be reflected in a downward adjustment to CEPA's expenditure based estimates of TFP improvements for distribution companies.

4) Reliance on current cost accounts which is likely to understate the growth in the capital stock and overestimate the growth in TFP.

The use of current cost accounts will understate the growth in the capital stock and consequently overstate the growth in TFP. The price indices used to construct current cost accounts will be moderated by the impact of technical progress in the production of capital equipment. This leads to an underestimate in the growth of capital inputs and a corresponding over-estimate in the growth in TFP.

5) Non-standard approach to the determination of input and output weights.

Standard practice in TFP analysis is to aggregate inputs and outputs by using revenue shares as output weights and cost shares as input weights. However, on page 17 of the report, CEPA state that "For the TFP calculation the two input variables were weighted by revenue (i.e. opex/revenue and 1-opex/revenue)". CEPA use attributed weights of 2/3 and 1/3 respectively to weight customer numbers and units distributed. This is clearly a non-standard approach for which no justification is presented.

6) Fixing the share weight assigned to each input and output.

When different inputs (or outputs) grow at varying rates, the weights assigned to each input (or output), in their aggregation will be critical in the calculation of TFP change. Failing to allow weights to change over time will understate the contribution of the inputs that are growing at the fastest rate, thereby understating the growth in inputs over time. Consequently, the improvement in TFP will be overstated.

7) Undue reliance on short periods of time.

Annual changes in TFP are often highly volatile and trends can only be reliably estimated over several business cycles. A number of the estimates reported by CEPA are derived from excessively short time periods, including Norwegian Distribution (six years), Water and Sewerage (seven years), BT (five years) and Railtrack (seven years).