Inveralmond House
200 Dunkeld Road
Perth
PH1 3AQ

Nienke Hendriks
Senior Price Control Review Manager
OFGEM
9 Millbank
London
SW1P 3GE

Telephone: 01738 456400
Facsimile: 01738 456415

10 February 2004

Dear Nienke

Electricity Distribution Price Control Review – Second Consultation.

You have invited views on the above document published in December and I am pleased to attach our comments.

I hope that you find our comments helpful. We would be pleased to discuss any of the views expressed. In the meantime, we look forward to continuing to play an active and constructive part in the ongoing work on the price control review.

Yours sincerely

Rob McDonald
Director of Regulation

Electricity Distribution Price Control Review – December 2003 Consultation

Response by Scottish and Southern Energy plc

Timetable

In our view, there is still much work to be done on costs, both historic costs to assess comparative efficiency and forecast costs, in order to arrive at initial proposals for the price controls in June which are robust and consistent between DNOs. The areas we believe require urgent focus and early resolution (i.e. by the March consultation paper) are the normalisation adjustments required to compare DNOs on a like-for-like basis and the metering costs which are to be separated from the distribution price control. We would therefore suggest that these areas should be the main priority over the next few weeks.

More generally, we are becoming increasingly concerned that the project timetable looks tight. As a consequence, we would urge Ofgem to set out its position on as many of the policy issues as possible in the March paper to ensure that the overall project timetable is achieved.

Form, Structure and Scope of the Price Controls

Revenue Drivers

Provide revenue to reflect changes in costs due to load growth. The intention of the volume-related revenue driver was to protect DNOs against volatility in units distributed (compared with the forecasts assumed in the price control) and against increases in costs as a result of load growth. We see no evidence that this underlying logic has changed and therefore see no reason to change the current revenue driver. We would also agree with Ofgem's conclusion that there is no energy efficiency argument for removing units distributed from the revenue driver.

Capacity component. Although we recognise that many of the costs are actually driven by capacity, we do not believe it will be possible to arrive at a meaningful and robust measure of capacity which could be used as a revenue driver. Capacity varies by voltage level, hence units distributed and customers have historically been used as proxies to capacity.

NGC Exit Charges

We remain of the view that exit charges should continue to be subject to full pass-through for the following reasons.

i) Exit charges are not a controllable cost for DNOs. The charges are set by NGC and approved by Ofgem. DNOs have no direct influence over that process.

ii) We would firmly disagree with the statement that now that NETA is well established, the review of transmission charges "no longer constitutes a barrier to change.” By contrast, it is clear that transmission charges are subject to substantial regulatory uncertainty. In particular, NGC has recently adopted a fundamental change in its pricing methodology by moving towards a “plugs” connection charging approach and a DC loadflow model for TNUoS. Taking Southern Electric’s DNO area as an example, we believe that this will reduce exit charges by around £10m compared to current levels of £20m.

It is thus clear that a change in NGC’s pricing methodology – which Ofgem approved – has led to a significant (50%) change in DNOs’ costs. There is no guarantee that other changes will not be implemented by NGC/Ofgem before 2010. Accordingly, DNOs cannot reasonably be exposed to this regulatory risk.

Indeed, we note that the transmission charging methodology generally, and the specific tariffs, are subject to a new consultation under Ofgem’s BETTA project. We would therefore firmly reject any suggestion that there is greater certainty now about the level of exit charges going forward.

iii) Given Ofgem’s role in the charge-setting process and the existence of NGC’s overall price control, it is clear that exit charges are already subject to detailed regulation. There is therefore no consumer protection argument for changing the treatment of exit charges.

Wheeling Charges

Ofgem claim that the different treatment of wheeled units and NGC exit charges could create perverse incentives between the development of connections to the transmission system and development of local distribution networks. We firmly believe that this separate issue provides no justification for moving away from full pass-through of NGC exit charges. In particular:

i) We are not aware of any specific examples where such a distortion has occurred in practice. If distribution level voltages are used for large power transfer, significant electrical losses result and the actual transfer capacity is limited. While there may be some inter-DNO 132kV links for historic reasons, the transmission system would be the medium of choice for, as its name suggests, the bulk transmission of power. We therefore believe that the potential trade-off between distribution and transmission connections is overstated;

ii) It is clear that the scale of the wheeled units issue (at £2.75m in 02/03) is an order of magnitude less than that of NGC exit charges (which were £247m in 2002/03). We therefore believe that fundamentally changing the incentive regime on exit charges to address a much smaller perceived (but unproven) problem with the treatment of wheeled units would be a dis-proportionate regulatory response; and

iii) There are, in any event, other solutions to any potential problems with the treatment of wheeled units for the recipient DNO. The charges for the service could be capitalised rather than expensed in lieu of the investment avoided.

This would address any residual incentive to "avoid" wheeled units as an alternative solution where it is practical to do so.

EHV Charges

Excluded service. We do not see how bringing EHV charges within the price control would improve protection to EHV customers. DNOs are already required by their licences to apply to EHV charges the assumptions underlying the current price control. DNOs have a one-to-one relationship with EHV customers and we are aware of no complaints about this principle having not been applied. In addition, it is clear that EHV customers are further protected by their right to have Ofgem determine disputes which, as stated in the paper, is now subject to a simplified procedure.

EHV charges are treated as an excluded service because charges vary considerably between customers according to the assets installed and the proportion of those assets which the customer wished to finance up-front rather than through ongoing charges (i.e. they are site specific). As a consequence, moving EHV charges into the main price control would require revisiting each individual EHV site to assess what assets should be included in the RAV and the ongoing cost of operation. This would be a considerable task and could lead to some movement in charges for particular customers (up and down) if a single charging methodology was to be applied going forward.

For these reasons, we believe that EHV charges should continue to be treated as an excluded service.

DNOs publish basis of charges. We could not support Ofgem publishing guidelines on setting EHV charges given the site-specific nature of such charges. Indeed, we believe that the application of a uniform charging basis could lead to disturbance to existing customers' charges (both up and down). However we could accept publishing additional information about our methodology for arriving at our charges, if customers would find this information useful.

Non-Contestable Connection Charges

We would see the regulatory arrangements for new connections going forward as follows.

- *Contestable work*. This should be removed from regulation as it is a competitive activity and there is a real danger that the introduction of price controls would distort competition. Indeed, it would be particularly bizarre for Ofgem to introduce price controls into an area that has been an excluded service since privatisation at the point in time when competition is developing.

- *Reinforcement*. Where not paid for by the customer, this would continue to be capitalised. With the move to shallower connection charges, the 25% rule will have to be reviewed so that the customer only has to pay for his share of the reinforcement required. It is also vital that allowances for future load-related capex fully reflect the change in connection charge policy.

- *Non-contestable work*. This should continue as an excluded service. Some activities may be charged on a transactional basis (e.g. approval of designs), but such charges will not produce significant revenue and volumes will be unpredictable. Other non-contestable activities, for example reinforcement required to be paid for by customers, will vary significantly according to the size and type of connection. Claims of excess returns being made by the DNOs are unsupported, and in any case customers already have a right to seek a determination from Ofgem. As a consequence, rather than bringing these charges within the price control it may be more appropriate to develop one or two further service standards.

  With regard to the determination process, we are particularly concerned that customers may use Ofgem determinations simply because they want the DNO to carry out the work but at the price a competitor has quoted. This is an inappropriate use of the determination process and we would therefore propose that customers should not be allowed to seek a determination where they are able to obtain an alternative quote.

- *Cross-subsidising competitive business*. We do not understand the comment made about DNOs cross-subsidising their competitive business. This would imply making low returns in the non-contestable work, not excess returns. In any event, there is no evidence to support either (conflicting) claim.

Business Rates

Business rates are set for five years, coincident with the price control period. Once set, and this looks likely to be before the DPCR4 Final Proposals, then these are no longer a controllable cost for the remainder of the price control period and should continue to be treated as a pass-through cost. It should also be noted that the appeal mechanism is not robust (i.e. if the Business rate does not raise the income required by the Valuation Office then they can revert to prescription). Against this background, it would be unacceptable to expose DNOs to a significant risk that they are not able to manage.

Dealing with Uncertainty, New Obligations and Costs

It is apparent that DNOs are facing a large number of new obligations over the next price control period which will have significant implications for costs. We do not regard the promise of “comfort letters” as acceptable protection from such legitimate costs. Some of the potential cost liabilities are large and could threaten a company’s ability to raise finance (e.g. Lane Rentals). However, other sources of additional cost, while maybe not substantial on an individual basis, can accumulate to large amounts. For example, the cost of making the IT changes required as a result of regulatory changes to the processes underpinning competition in supply which frequently occur during the price control period (examples that have happened in the current price control period are the changes required to allow private networks and to allow the development of competition in metering).

We firmly believe that there must be a robust mechanism for potential recovery of these costs. We believe that in broad terms this could be achieved by setting out, formally, in the licence, a process for appeals on new costs which were not anticipated at the price review. This would clearly need to include a de-minimus limit. It would also, in our view, need to include a right to appeal Ofgem decisions to a third party, probably the Competition Commission.

Ofwat Approach to Uncertainty

We would firmly reject the comment in the paper that differences in Ofgem's and Ofwat's statutory duties would prevent Ofgem from introducing a formal mechanism for dealing with cost uncertainty between reviews. Ofgem too has an obligation to secure that companies can finance their functions and this is clearly consistent with the principal objective to protect customers. We do not believe, therefore, that there is any material difference in law between the obligation on Ofgem to secure that companies can finance their functions, and the similar obligation placed on Ofwat by its statutory duties.

Incentive Framework

- *Average costs*. We remain of the firm view that the frontier costs/glidepath methodology used to set allowances going forward in DPCR3 significantly weakened efficiency incentives compared to the average costs methodology used previously. Not only does it fail to reward the frontier companies for "revealing" the efficient level of costs but perversely it rewards the inefficient companies. We attach a paper (Appendix 1) that we have previously submitted on the incentive properties of the "average costs" methodology and would welcome Ofgem's views. In essence, the advantages of the average costs methodology are that it better replicates a competitive market. The main features are set out below:

(i) A firm will always be better off than it would without a cost reduction, whereas under a frontier approach, if a company performed well it received a tougher target. Therefore there is no incentive to delay savings (i.e. it fully resolves periodicity concerns);

(ii) Allowances are related to factors exogenous to the individual company's performance;

(iii) Companies that perform well make higher returns; and

(iv) Customers pay the same whether served by efficient management or inefficient management.

- *5 year fixed retention period for opex efficiency savings*. We have a number of concerns about this proposed mechanism, which are set out below.

(i) It is clear that the five year retention mechanism will not resolve the periodicity problem. So long as there is any regulatory uncertainty about past performance influencing future targets, there will be a residual incentive to delay cost savings. As noted above, this issue does not arise with the average cost methodology.

Moreover, it is clear that the five year retention period, in conjunction with the frontier methodology adopted at the last review, will weaken incentives for frontier companies. In particular, since the "laggards" were only required to move 75% towards the frontier at the last price review (and given four years to do so), they received a positive benefit relative to the frontier companies. That is, they were able to retain 25% of the reduction that the efficient companies had already achieved. It is apparent that the five-year retention mechanism will allow those companies to benefit twice from this 25%, further undermining incentives on the efficient companies.

(ii) Putting this aside, we firmly believe that if the five-year retention term is to have any effect on incentives at all, it needs to be reflected in the price control formula, rather than "rolled-up" for inclusion in the 2010 review. In particular, we believe that the regulatory risk associated with a possible "reward" in 2010 will mean that DNOs in practice will not take the mechanism into account in making decisions before that date.

(iii) We support the reasons for not introducing an eligibility test for applying the new incentive term for the remainder of the current price control. However, going forward, there has been no discussion to date about how such a test might work (e.g. the developing of relevant outputs or the linking to capex). It is also apparent that under Ofgem's approach, DNOs will not actually receive additional revenue under this scheme until the 2010 review. Accordingly, if the mechanism is to work as intended and encourage efforts to reduce costs, DNOs will need to be confident that their efforts will not be undermined (i.e. savings "disallowed" from the new mechanism) at the next review. We therefore believe that vague and subjective "eligibility" tests will undermine the effect of the incentive mechanism.

(iv) We fail to understand the point being made about the exclusion of exceptional/atypical items. The document states that these items will not be excluded because "it is difficult to define ex ante what qualifies as an exceptional/atypical item". Exceptional/atypical items vary from year to year and between companies. Failing to exclude them risks significantly weakening the incentives to continually seek out efficiency savings and in fact runs counter to the intention of the rolling opex incentive.

- *Efficiency multiplier*. We note that Ofwat have recently concluded that a significant multiplier for the five year retention period is justified to reward frontier performance. As we have previously stated, we are firmly of the view that the frontier companies (and by this we mean lowest cost) should be rewarded for continuing to drive the cost frontier down.

  As discussed above, the "glidepath" methodology introduced in DPCR3, although it forced the "laggards" to reduce costs, still allowed those companies to earn higher returns than were available to the frontier companies (i.e. the "laggards" had only to catch up 75% of the way to the frontier and the 25% "cushion" represented significant amounts of additional return). The frontier companies were not allowed the 25% "cushion" in reverse; instead an arbitrary 1% of additional revenue was allowed. This in our view did not adequately reward the frontier companies.

Ofgem recognise that they would expect frontier companies to be earning higher rates of return. We believe this will be found not to be the case in practice (i.e. the DNO returns will support our argument that the frontier methodology is unfair by showing that the efficient companies at both DPCR3 and the current period are not those earning the highest returns). As a consequence, if Ofgem do not adopt the average cost approach, another mechanism will need to be put in place to recognise the performance of the frontier companies. The Ofwat multiplier approach may be such a mechanism.

- *Treatment of capex overspends*. We note that some DNOs have proposed large increases in capex spend in their business plans. We are not in a position to comment on the plans of other companies, but there is without doubt a need for some increased spend by most companies to avoid networks deteriorating and to maintain current levels of performance. We believe also that there is justification for a modest increase in expenditure to improve performance (although we continue to believe that the benchmarks assumed by Ofgem are unrealistic) and network resilience (which Ofgem's survey revealed that customers are prepared to pay for). Our submitted business plans explain and reflect this view.

  However, Southern Electric Power Distribution at DPCR3 was penalised 1% of allowed revenue per annum for having carried out the investment in resilience which some companies are now proposing. We still firmly believe that this expenditure was efficient and the benchmark performance of the network in the October 2002 storms was strong evidence of this. We believe, given other DNOs plans, that it would be grossly unfair not to reimburse that penalty, for example by adding c. £15m to SEPD's RAV.

  Going forward, we agree that it would be appropriate to clarify the rules on future overspend of capex allowances. Our preferred approach would be some form of "logging up", probably for large overspends. However, we are particularly concerned at the suggestion that Ofgem may need to re-think its policy on the rolling capex incentive mechanism, which was one of the few areas within the review where the policy had seemingly been clarified.

  We firmly believe that the 5-year capex incentive should be retained in substantially the form put forward by Ofgem. However, as with opex, we believe that the incentive term should be a substantial part of the price control formula rather than "rolled up" for inclusion in the 2010 price review. In addition, to avoid regulatory "gaming", any significant increase in capex should be accompanied by clear output targets, rather than new and complicated "sliding scale" incentive mechanisms.

Price Controls for Metering Services

For the reasons set out in previous correspondence, we continue to believe that there is no justification for separate price controls on metering services. Putting this aside, separate metering price controls imply removing costs from the main distribution price control. We have put forward to Ofgem our view of those costs as part of the business plans and, as part of the business planning process, would welcome confirmation from Ofgem that these figures will be used in making any such adjustment. We believe that our proposals would ensure that sufficient costs remain in the distribution price control to cover the potential stranding (i.e. premature replacement) of assets, and the fixed costs associated with DNOs' licence obligation as Meter Asset Provider and Meter Operator "of last resort".

We have been concerned for some time that there is still much to be done in this area and welcome the recent setting up of Ofgem's working group to take forward the issues surrounding the separation of metering from the distribution price control. It is nonetheless vital that Ofgem progress this work as a matter of some urgency if the overall timetable for the price review is to be met.

- *Stranding*. The Depreciated Replacement Cost methodology for valuing the assets to be removed from the distribution RAV does not fully protect DNOs from stranded costs. Unless DNOs are able to recover their investment in existing meters, installed under a licence obligation, this will raise significant issues of regulatory risk. It will also damage incentives to invest going forward.

- *Competitive market review*. We welcome the removal of price controls, wherever appropriate. However, we remain opposed to the separation of metering from the distribution price control which we do not believe delivers benefits to the end customer which outweigh the additional complexities and costs involved. All that is being achieved is to make metering an increasingly risky and unattractive activity to DNOs, with the likely outcome at some point in the future of the regulated DNOs being replaced by unregulated monopolies.

- *MAP price cap / MOP average revenue cap*. We are not clear how an average revenue cap would take into account changes in the mix of activity or loss of market share (e.g. would the cap be per transaction or per customer?) A simpler approach might be to simply establish a price cap for the basic main activities (i.e. the rental charge and the installation charge for a basic domestic meter), with any other activities subject to commercial negotiation with suppliers.

Quality of Service and Other Outputs

<u>Overview</u>

We are concerned that the development of quality of service regulation is becoming increasingly complex, costly to administer (both for DNOs and for Ofgem) and is exposing DNOs to significant additional financial risks. We have set out comments below on the detailed issues raised in the paper. However, in general terms we believe that there should be an overall cap on DNO financial exposure of 2% of allowed revenue. This should include exposure to IIP, guaranteed standards, storm compensation and any other quality of supply output measures. Any exposure above this level would raise significant issues of regulatory risk which were not present at the last review and which would need to be fully reflected in the allowed cost of capital.

In addition, to ensure that the cost of administering the various quality of supply incentive mechanisms is not excessive, we would propose a simple "sense check" test that Ofgem's monitoring of the new quality of supply regime should not involve greater staff numbers than presently employed in that process.

Finally, it is apparent that the final suite of quality of supply standards will have implications for DNOs' investment plans and ongoing operating costs. The price control review process will therefore need to include the opportunity for DNOs to re-state business plans in the light of the standards package imposed by Ofgem.

<u>Guaranteed and Overall Standards of Performance</u>

- *Replacing interim arrangements*. We are firmly opposed to any proposal to remove the Force Majeure exemption. The right to claim Force Majeure represents is an important cap on DNOs' financial exposure to events that are outwith their control. Its removal would result in a significant increase in the risk to which DNOs are exposed and would have to be compensated for elsewhere.

  We also see no need to tighten the interim arrangements for compensation payments in storms. They clearly need formalising through the licence but the arrangements in their present form represent a workable solution accepted by all parties and it is premature to propose changes. In particular, any suggestion of a link to performance places a considerable additional risk on DNOs. That is, DNOs could be exposed to penalties through the Guaranteed Standards, IIP and interim arrangements (companies could also be penalised through any eligibility test to the rolling incentives). This is unjustified, complex and unacceptable.

- *Splitting GS2 into normal weather and severe weather*. This is unnecessary given the above arrangements.

- *Business customers*. It is not practicable to have quicker response times for business customers, as most business customers are embedded in the LV network alongside domestic customers. It is not possible, and we do not believe this can even be defended, to favour them in supply restoration over other classes of customer.

  With regard to compensation payments, the Guaranteed Standards were intended to compensate customers by exception where an expected level of service was not met: they were never intended to compensate for consequential loss. Clearly, any substantial increase in compensation amounts would increase the financial exposure of DNOs which, either through the cost of capital or more direct means, would be paid by other customers. We do not consider that such a cross-subsidy would be acceptable and hence the appropriate protection is for customers to take out insurance.

- *Semi-automatic payments*. While we acknowledge that customers would seem to prefer automatic payments, there is no evidence that they are prepared to pay the resultant significant costs to improve customer / network connectivity to identify when such payments would be due. This applies equally to the 'semi-automatic' payment of compensation. In addition, the suggestion of making payments semi-automatic is impracticable and would carry a considerable administrative burden and cost. For example, Ofgem's suggestion would involve – literally – sending out millions of letters to customers over the course of the year. Neither would such an approach reflect customers' expectations of compensation. In our view, customers should therefore continue to be required to claim compensation.

- *Priority consumers.* We understand the logic for considering what additional steps could be taken to protect priority customers. However, in the event of severe interruptions to supply, it would be impractical for DNOs to be able to separately identify such customers when their main aim is to get as many customers as quickly as possible back on supply. In addition, the existing priority register is complex and relies on other parties to keep it up to date. Thus, in our view, the appropriate parties to initiate or respond to needs to protect such customers are suppliers, the caring agencies and hospitals.

- *Scope of exemptions*. Removing the exemption for industrial action by a DNOs employees will actually have the opposite effect to that intended. It will increase the likelihood of industrial action as a lever against management and will correspondingly increase costs.

- *Voltage complaints*. We are not aware of any customer dissatisfaction with the current standards.

- *Role of the overall standards*. We would support removal of the Overall Standards, since they have been superseded by IIP and Ofgem's other quality of supply initiatives. However, we are not convinced that the overall standards need to be brought within IIP. The reporting requirements under IIP are already considerable, and we would expect to see a robust justification, and recovery of the costs involved, of extending those requirements.

- *The scope of the guaranteed standards*. The fact that some Guaranteed Standards do not have many payments made against them does not mean they are not working. The original intention of these Standards was that companies should be able to avoid payments by efficient management action. However, the Multiple Interruption Guaranteed Standard represented a radical departure from this principle, imposed by Ofgem. This standard has an implied/expected failure rate and this exposes DNOs to excessive risk. It is our firmly held view that this standard should be removed.

<u>Reviewing IIP</u>

- *Distinguishing between types of consumer*. As noted above, we would be opposed to any increase in reporting requirements without a robust justification of the aims and benefits. We would also be opposed in principle to discriminating between customers as to the underlying level of service provided.

- *Protecting worst-served customers*. Bringing worst-served customers into IIP risks introducing an incentive which conflicts with the underlying aim of IIP (i.e. to incentivise performance delivered to the average customer). It would also introduce substantial complexity into the scheme and increase administrative costs. We would therefore not support any such extension of IIP.

- *Disaggregated performance*. We recognise the need to formalise the collection of disaggregated information within IIP and we support the aims of disaggregation. However, we remain concerned that there are several outstanding issues associated with disaggregation and there is therefore still much work to be done before we could accept the targets coming out of this work. We have written separately about our concerns in this regard.

- *Moving to a symmetric scheme*. We support moving to a symmetric scheme with rewards and penalties in each year. This was always our expectation of IIP, which Ofgem have yet to deliver on. As noted above, we believe that DNO exposure (and reward) should be limited to a 2% overall cap (including exposure on guaranteed standards, storm compensation and any other quality of supply measures).

- *Use of deadbands*. It is possible that a DNO could fail its annual targets due to underlying weather performance, not within its own control. Perversely, it is the companies which perform better in storms that are most exposed here. For example SEPD, which is recognised as having benchmark network resilience, will have less events excluded from IIP than a poorer performing company. The use of a limited deadband would help account for this distortion.

- *Rolling average performance*. The use of rolling averages seems unattractive for the prime reason stated in the document i.e. poor performance in one year may make it difficult to meet targets for several years and therefore weaken incentives.

- *Targets, incentive rates and financial exposure to the incentive scheme*. There is, in our view, no justification for increasing the amount of revenue exposed to IIP. Indeed we believe that all the various risks under GSs, IIP and the interim arrangements should be in aggregate within this 2% cap.

- *Planned interruptions in final year of the current scheme*. This additional incentive seems complex and entirely unnecessary. Programmes involving planned interruptions are already in place for the final year. It also seems unlikely that DNOs will risk deferring planned interruptions, to put them at risk to penalties in the first year of the revised incentive scheme when they do not know yet what that scheme will look like (and will not do so with certainty until the financial year is almost over).

Network Resilience

- *Existing incentives relating to network resilience.* By in effect disallowing SEPD's spend on resilience in DPCR3, Ofgem sent a very clear message that resilience was not a major aim for Ofgem. We substantially cut back our planned spend on resilience in response to that message. However, we continue to regard resilience as very important and therefore we have included an amount in our business plan to increase the resilience spend going forward. However, Ofgem could send a clear signal to DNOs about the importance of network resilience (and hence improve incentives) by rewarding those companies that achieved a benchmark performance in the October 2002 storms. In the case of SEPD, this could be achieved, in part, by returning the £15m penalty imposed by Ofgem at the last review for investing in the network to improve resilience.

- *Improving the ability of the network to withstand severe weather*. To gather the statistical information to link the performance of the network to weather will clearly take some time. Although our internally developed model provides a reasonable prediction of damage levels, it can be inaccurate. For example, if the storm is slow moving or contains a complicated series of fronts within the weather system, the model could be greater than 50% in error. We propose to continue the development of our model to assist our assessment of likely network damage, but believe it is unlikely to ever be robust enough to ascertain actual performance comparisons.

  We therefore favour an input based approach. The key issue regarding wind storm resilience is the proximity of the network to trees, and there are only three fundamental actions that can be taken at high impact points on the network to reduce the risk:

  1. Clear the trees back to falling distance;
  2. Divert the network to a tree-less route or underground the section; or
  3. Install covered conductor technology.

  Each option has its merits and costs. If we are going to improve network resilience for the national interest, then we need to undertake a combination of the above activities, which are measurable and reportable, and do not require intrusive monitoring or detailed management of DNOs' plans by Ofgem.

- *Ability of a company to respond to a severe weather event*. We have commented on this above. Our prime concern is that companies exposure to these several incentive schemes i.e. GSs, Interim Arrangements, IIP, Rolling Incentive, should be capped overall and we suggest the appropriate cap to avoid placing more risk on the DNOs is to use the current IIP cap i.e.2% of allowed revenue;

- *Management of communications during an event*. Our comments in the paragraph above apply.

<u>Incentives for Telephone Response</u>

- *Scope of consumer survey*. Companies' performance is already very good. It is also converging. As a consequence, there is an increasing risk of penalties simply because the range of performance is narrow and hence there is a risk that DNOs could be exposed due to, for example, measurement error. We would therefore support removal of this financial incentive. Indeed, we believe that the survey serves no useful purpose going forward and inhibits good customer service. Of particular concern is the requirement for data protection reasons to include an automated message to the effect that customer details may be passed to Ofgem. This causes delay in the transfer of vital information during a fault. It also causes considerable (and understandable) irritation to customers. Finally, it is apparent that the telephone surveys involve significant cost to Ofgem and the companies. We would therefore urge Ofgem to consider abandoning the routine telephone surveys.

If necessary, this could be replaced by occasional “mystery shopper” surveys, which is an approach that has been adopted by other departments within Ofgem. Any DNOs with poor performance under these “mystery shopper” surveys could be “named and shamed” which, again, is an approach which has been successfully adopted by other departments within Ofgem.

- *Survey bias*. We do not believe that there is any objective evidence to support the contention that survey results are biased by differing customer expectations.

- *Automated messaging*. Automated messaging is a fundamental requirement to deliver good customer service when faced with extremely volatile call volumes. Although we would not oppose the principle of including RVA calls in the customer survey (should it continue), it will be very difficult to achieve. Some of the challenges include:

  1. Data protection;
  2. Some service providers being unwilling or unable to provide CLI information;
  3. Risk of duplicated surveys for callers who have heard the RVA; and
  4. The inability to identify who actually made the call.

Environmental Outputs

We believe that environmental considerations are already covered by other agencies, and there will be an inevitable duplication of effort and resource if Ofgem seek to impose further environmental regulation. The issues raised in the consultation need further discussion. For example, it is unclear what measurable effect the insignificant amounts of SF^6 used in the industry have on the environment.

Other Issues

We do not believe there are any additional outputs on quality of service which should be measured or incentivised. It is, in our view, important to focus on a few key outputs, in order to avoid complex and confusing incentives.

Distributed Generation

We continue to believe that the proposed “hybrid” mechanism is overly complicated and unnecessary. With a licence obligation to offer terms for connection, DNOs will carry out all the necessary reinforcement to accommodate DG in their areas without requiring a complex incentive scheme.

This mirrors the situation for load-related capital expenditure, which has continued since privatisation at a generally higher level, in each DNO area, than the future forecasts of DG-related expenditure. Load-related expenditure is regularly reviewed as part of the periodic price control reviews, has not been subject to complex incentives and no evidence has been put forward of any “gold-plating” of assets.

Connecting parties are further protected by their entitlement to request the Authority to determine the terms of any connection where there is a dispute between the customer and the DNO. We therefore do not believe that Ofgem have put forward a sufficiently robust case for experimenting with a new price control regime for connecting DG.

Moving away from the existing framework for RAV funding of DNO investment towards an alternative mechanism inevitably requires DNOs to assess the overall risks and rewards of the new scheme. In our view, while the main financial assumptions of the proposals are clearly set out in the consultation document, there is still a great deal of uncertainty about exactly how the scheme would operate. This uncertainty makes it difficult at present for DNOs to evaluate the risks of the proposals and make a judgement on these new risks and rewards.

We believe, however, that there is a very great danger, where DNOs perceive a risk that any of their potential investment will be rewarded at less than the cost of capital, they will delay that investment. Such a delay in investment would inevitably result in delays in MW connecting and adversely affect the Government's targets for the growth of renewable generation. Investment would also probably take place in an incremental, less than optimal manner as DNOs would, by definition, be incentivised to invest only where there is certainty that the resulting MW will connect. We also note that similar incentive schemes recently introduced in gas have not yet proven themselves to be effective.

For these reasons, we would urge Ofgem to re-think the overall approach to investment to connect distributed generation. However, putting these wider concerns aside, we agree with two of the characteristics of a successful incentive scheme that Ofgem outlines at section 5.16 of the document. These are that:

- DNO's should, on average, earn a return above the cost of capital for DG investments, but not excessively so; and
- DNOs should not face risks of returns below the cost of capital on their overall investment in DG connections.

To these, we would add the requirements that:

- There is a fair balance of risk and reward for each DNO;
- The likely costs of connecting DG in each DNO area is recognised; and
- DNOs are only exposed to risks which they can control.

Our comments below are therefore aimed at ways in which the incentive proposals can be clarified and refined taking the above points into account.

<u>Comments on Ofgem's Proposals</u>

We have modelled the effects of Ofgem's proposals on the overall return to a DNO under various scenarios and would make the following comments on the detail of the proposals.

- Ofgem have carried out their modelling on an annuity basis, which overstates the present value of the return actually obtained from pass-through funding. This is explained more fully in Appendix 2, but the practical effect is the reduce the minimum guaranteed return of the incentive scheme from the 1.4% and 3.2% for options A and B respectively to 0.87% and 2.85%.

- The following table shows the range of overall returns obtained under options A and B as the average reinforcement cost of the scheme varies. A further distinction is made in the table between a scenario where 100% of the expected MW appear, compared to the scenario where only 50% of the expected MW appear.

Illustrative variation in overall project return under Ofgem's DG incentive proposals, depending on average £/kW DG cost and % of expected MW that actually connects

	Option A (£2.5/kW)		Option B (£1.5/kW)	
£/kW	100% MW	50% MW	100% MW	50% MW
20	18.97%	11.01%	14.16%	8.99%
30	13.80%	8.01%	10.79%	7.09%
40	11.01%	6.40%	8.99%	6.09%
50	9.24%	5.39%	7.86%	5.48%
60	8.01%	4.69%	7.09%	5.06%
70	7.10%	4.18%	6.53%	4.76%
80	6.40%	3.79%	6.09%	4.53%
90	5.84%	3.49%	5.75%	4.35%
100	5.39%	3.24%	5.48%	4.20%
150	3.98%	2.48%	4.63%	3.76%
200	3.24%	2.09%	4.20%	3.54%

- The table illustrates the wide variation in DNO returns depending on the average cost of connecting the DG schemes. The information provided in Ofgem's October update paper shows that projected average reinforcement costs to accommodate DG in the "Future Forecast" scenario vary between DNO areas from about £15/kW to £90/kW. SSE's Scottish Hydro-Electric DNO area is towards the top end of this range and, under Ofgem's proposals, faces average returns below the cost of capital even if all expected MW connect. Other DNO areas with lower average costs, on the other hand, would enjoy returns above the cost of capital – in some cases even if only 50% of expected DG MW appear. Such a wide range of returns is unacceptable. Incentive rates will therefore need to be tailored to each individual DNO's expected £/kW reinforcement cost.

- We would challenge Ofgem's comment, in paragraph 5.20, that some of the variation in DNO costs "may be due to differences in categorisation of costs or connection policies". It is reasonable to expect that the combination of different geographical areas and different potential DG technologies will result in different £/kW reinforcement costs in different DNO areas. In particular, the cost for schemes in the Scottish Hydro-Electric area are well founded on actual connection schemes with a total of 5GW of active developer interest across the transmission and distribution systems in this area. We also note that Ofgem's consultants concluded that "that the efficient level of connection cost per kW of DG is very variable". This further supports the use of specific figures for each DNO.

- Ofgem's discussion in the consultation paper centres around the effect of the proposed incentive scheme on the "typical DNO portfolio costs of £50/kW". As noted above, actual DNO costs vary widely around this average figure. We do not agree that operating and maintenance (O&M) costs should be converted from the typical 1-2 per cent of capital cost to a £/kW figure using the "typical" £50/kW costs and then applied uniformly to all DNOs. As with the main incentive scheme, this penalises DNOs with higher than average costs to connect DG. Instead, O&M costs should be subject to the same recovery mechanism as the capital costs with a percentage passed through and a smaller percentage added to an appropriate DNO £/kW incentive rate.

- There are some "infrastructure" investments that should not fall under the hybrid mechanism as the investment required is typically much larger than the average reinforcement required for a single DG connection and the risk that expected MW may not appear is much greater than in the cases of specific connections. Examples might include connection to specific island groupings. Moreover, that risk is not within the DNO's control. Such investment should be discussed as part of the price control review and passed through into the RAV, either by explicit allowances in advance, or some form of "logging up" for investment undertaken between price control reviews.

- Ofgem suggest that DNOs could choose a risk/reward package appropriate to their business. We welcome this aspect of choice in principle, but the options available will have to be extended to provide similar risk/reward packages for all DNOs. If options are provided, and DNOs make a choice, then we agree that the choice should not be capable of being varied until at least the 2010 price review.

- We still have concerns with Ofgem's proposals for incentives on ongoing network access that have been mentioned in publications on the DG incentive and also within the documents concerned with the development of distribution charging. We note that Ofgem refers to the Renewables Directive (2001/77/EC) as justification for this type of "compensation" mechanism. However, the Directive only comments that financial compensation "**may**" be included in arrangements to ensure that transmission and distribution operators guarantee the output of generation from renewable generation as set out under Article 7. It does not actually require a compensation regime.

  There is no doubt that the payment of compensation to generation sites would increase the potential financial liability of DNOs, particularly in areas with large amounts of MW forecast to connect, and this factor would need to be considered as part of the price control settlement (i.e. DNOs would need a baseline "allowance" for anticipated costs).

  The proposal for a £/kW/hour compensation rate brings with it the complications of assessing whether generation sites were actually seeking to use their connection (and at what load factor) when the interruption occurred. There seems no justification for multiplying the hybrid scheme incentive rate by 10 to arrive at the proposed rate of £2/MW/hour. This is also roughly four times higher than the maximum generator use of system charge of about £5/kW (5000/8760 £/MW/hour) that Ofgem has put forward in charge structure discussions. The proposals seem arbitrary and we do not support the development of this type of incentive mechanism.

- Ofgem will be aware that we have strong concerns that certain types of DG connecting in the north of Scotland will increase distribution losses. It should be recognised within the distribution losses incentive scheme under development that this will be the case in certain DNO areas where renewable resource is situated well away from the robust, interconnected distribution network already serving high levels of load.

- Ofgem have based the indicative figures on an assumed cost of capital of 6.5% pre-tax. We believe that this is in sufficient and that a post-tax cost of capital should be applied in the next price control period. As a consequence, we agree that the specific figures for the incentive scheme will need to be revisited to ensure consistency with the other elements of the price review.

Way Forward on Hybrid Mechanism

Our main concern in developing the DG incentive proposals are to establish a fair balance of risk and reward for each DNO and to clarify the operation of the scheme so that risks can be assessed. We have five specific proposals to achieve this.

Firstly, we propose that DNOs should not be exposed to a risk that any investment will earn less than the cost of debt – at around 5% (using Ofgem's illustrative cost of capital of 6.5%), with a maximum return some 1-2% above the cost of capital. This would provide a reasonable range of investment returns, consistent with the legitimate expectations of DNO shareholders. Our modelling suggests that a pass-through rate of 92%, coupled with an incentive rate of £0.8/kW/annum would provide a guaranteed minimum return of 5.08% with a correspondingly narrower range of total project returns.

At the extremes of the table above, for example, an average cost of £20/kW would give a range of return from 8.3 to 11.2% as actual MW varied between 50 and 100% of expected MW while an average cost of £200/kW would show a variation between 5.4 and 5.8% in the same circumstances. While this represents a more acceptable spread of returns, it would still be necessary, in our view, for £/kW incentive parameter to be tailored to individual DNOs' expected costs in order to provide similar incentive properties to all and avoid windfall gains for some.

Our second proposal relates to the treatment of particularly expensive schemes. We do not believe it is reasonable for DNOs to see the unlimited risk of particularly expensive schemes being included in the scope of the incentive scheme. These schemes should not be subject to the incentive mechanism, given the inherent risks. Rather, the schemes should be subject to a separate Ofgem process which (if appropriate) provides for the costs to be "logged" up for inclusion in the RAV.

To clarify and contain risk to DNOs, our third proposal is that MW should be "counted" for the incentive scheme as soon as the generator signs a connection agreement. This is both readily audited and coincides with the point at which the generator makes a legal and financial commitment to the project. It is also the point at which a DNO would normally start any necessary reinforcement works, consistent with the project timetable. It is difficult to see any other point in the process that would combine these advantages. While there can be a delay between the date of signing of the connection agreement and the actual electrical connection being commissioned, it is precisely this period in which the DNO's capital investment has to be delivered. This approach would therefore match the start of the incentive term revenue stream with the financial year in which the investment is made. Ofgem must recognise, however, that even this approach is likely to result in a delay in bringing forward investment to accommodate new renewable generation (unfortunately, this is an inevitable outcome of any scheme which provides for less than 100% pass-through).

Fourthly, once the MW have been counted for the incentive scheme, they should remain as part of the incentive for the full 15 years irrespective of the continuation of the actual DG schemes. If this were not the case, DNO returns would be subject to all the risks facing DG developments. In our view, it is unacceptable for DNOs to be exposed to the range of economic considerations affecting the viability of the generation market, including the path of renewable benefits such as ROCs, which may be key to the economics of some schemes. Such risks are not within DNOs' control and cannot be fully compensated by the narrow range of returns around the cost of capital discussed above. Thus, in our view, once a DG scheme has connected, the appropriate MW should stay in the incentive term for the appropriate term irrespective of whether the scheme subsequently stops operating.

Finally, there is an area of regulatory risk relating to the duration of the incentive scheme. We support the 15 year timescale proposed but note that this extends the mechanism over 3 different price control periods. Ofgem should provide a commitment to the finalised DG incentive scheme proposed as part of the 2005 price control in the 2010 and 2015 reviews.

In summary:

- Incentive scheme parameters should reflect the projected DG connection and O&M costs in each DNO area;

- With a pass-through rate of 92%, no DNO would see a return on investment lower than the current cost of debt, at about 5%;

- Strategic investments should not be incentivised through the hybrid mechanism but be fully RAV funded;

- Schemes with particularly expensive reinforcement costs should not be subject to the incentive scheme. The schemes should be subject to a separate Ofgem process which (if appropriate) provides for the costs to be "logged" up for inclusion in the

RAV; and

- Risks associated with MW connecting and leaving the system together with regulatory risk should be explicitly addressed as discussed above.

If these elements of the proposed hybrid scheme are suitably tied down, then it is possible that DNOs will be able to accept such an incentive scheme. If these are not acceptable to Ofgem, then a further possibility would be to relax a DNOs "duty to connect" in circumstances where the price control incentive scheme will not allow legitimately incurred costs to be recovered.

Registered Power Zones and Innovation Funding

Ofgem has developed its thinking on the Innovation Funding Incentive (IFI) and Registered Power Zones (RPZ) concepts. Against the background of DNOs connecting and operating systems with potentially much larger quantities of DG than at present, we agree with the objectives for IFI to incentivise R&D activities and for the RPZ to encourage the demonstration of novel connection and operating strategies. We also agree with the approach of open, public reporting of activities under these schemes, supplemented by selective audit, as required.

In relation to the IFI, there will not be much incentive for DNOs to come forward with R&D projects unless the percentage of pass-through funding is virtually 100%. As Ofgem has observed, DNOs currently show a low level of R&D expenditure compared to overall turnover. There will be no reason for DNOs to change this behaviour, unless they have reasonably certainty that the costs of the additional expenditure will be covered in full. If Ofgem want to see more R&D carried out by the industry in relation to DG, the IFI will have to be kept simple and the funding will have to be near 100% for all the years of the price control period.

In relation to RPZs, Ofgem has taken some steps to simplify the proposals, which is welcome. What is needed, in our view, is a clear statement of the funding that will be available for RPZs, plus details of the registration process supplemented by guidelines on the types of characteristics that will be considered for allowing an RPZ. It would be counter-productive for Ofgem to be too prescriptive about what an RPZ should contain as this might rule out some feasible projects. In our view, an RPZ might consist of an area or project where investment is proposed that might exhibit some or all of the following elements:

- Relaxation of the connection offer timescales;
- Relaxation of standards of performance;
- Relaxation of engineering standards;
- trial of a different approach to technology or process of connecting DG;
- greater "active management" of generation / load balance; and/or
- increased risk of DG MW not connecting, but **not** any additional risks of stranded assets or liquidated damages towards generators.

Each DNO bringing forward a proposed RPZ project would have to clarify what relaxations were required, as well as the technical details and the potential for further adoption of the technology that is being trialled. The proposed project could be reviewed by an independent expert advisory panel as Ofgem proposes. On the panel, it would be appropriate to have some DNO and some generator representatives. The terms of reference for the panel should include a brief to check that proposals represent genuinely novel ways of connecting or operating the system but should not try to take a view on the likelihood of success for the proposal or the "degree of innovation" it represents. In other words, we favour having only one category of RPZ scheme and one incentive rate.

In the case of SSE's north of Scotland DNO area, the main connecting DG technology is expected to be onshore wind farms. The sort of areas, in this context, in which we expect to develop investment and operating approaches are in intertrip schemes, power flow management and voltage control. These will also apply at the 132kV voltage level which we assume will qualify for RPZ status.

In terms of the incentive level for RPZs, we agree with Ofgem's intention to link this to the main DG incentive. However, as there is still uncertainty on how the main incentive will operate, RPZ funding is still similarly uncertain. In our view, the premium incentive rate should apply for the full term of the main DG incentive i.e. 15 years and a doubling of the incentive rate is the sort of level where a clear premium will be seen. This clear additional funding above the main DG incentive will encourage DNOs to seek out the more marginal opportunities to connect DG. However, the incentive element should be available to the DNO, as we have argued in the main incentive scheme, as soon as a connection agreement has been signed by the generator, not linked with any commissioning dates.

We understand Ofgem's wish to put in place an overall cap per DNO on the amount of RPZ funding available. However, the proposed level of £0.5m per DNO per year is, in our view, too low and a figure ten times greater than this should be considered.

<u>Points Raised in Appendix 1</u>

In this section of the consultation document, Ofgem raises various questions associated with the production of a Regulatory Impact Assessment for the main DG incentive mechanism, the IFI and the RPZ funding. Our comments on the issues raised are as follows.

The amount of DG connecting to DNO networks over the 2005-2010 period is one of the more uncertain elements of that period. As noted in our discussion of the main DG incentive, we are not convinced of the need to develop a complex incentive scheme in order to encourage the efficient connection of DG to DNO networks. The wider political and economic climate for generation, and particularly renewable generation, will be the major influence in determining how much DG seeks to connect to DNO networks. Much will also depend on planning criteria and the capability of transmission networks to cater for the increased flows expected at transmission level. There is also a planned change in distribution charging structure which is intended to bring a "shallower" connection charge boundary for DG, as well as the possibility of generator use-of -system charges, from 2005.

Against this background, it is difficult to make any concrete predictions on the likely effect, cost and benefit of the three incentive mechanisms. However, there will inevitably be challenges in accommodating DG, particularly with the less familiar technologies. In such a climate, incentives to innovate and try out different approaches are likely, all other things being equal, to lead to a greater quantity of DG being successfully connected. The benefits of innovation may also extend to developing more cost-effective ways of connecting generators and may also lead to operating cost benefits that will be seen by all customers. While Ofgem has proposed limits on the overall funding of the IFI and RPZ schemes per DNO (and for RPZs, we think this should be higher), it is difficult to predict what the take up will be across individual DNOs.

Ofgem has signalled that it expects generators to fund the costs of all the DG incentive schemes. We do not consider that it is necessary to do this as the costs could be spread, in common with most other DNO costs, across demand customers. On this basis, we do not believe the cost per customer would be material and it would remove one potential element of uncertainty in the proposed new generator DUoS charges.

Straightforward incentive schemes, with minimal bureaucracy and clarity on the additional funding that a DNO can expect for undertaking the innovation concerned are pre-requisites for a wide take up of the incentive schemes. By providing an enabling framework, Ofgem will contribute to the growth of innovation and developments in practice. It is perhaps not until the individual schemes are brought forward that an assessment can readily be made of the costs, benefits and impact of each.

We consider that, in the north of Scotland, much of the new DG will be renewable, with the benefits that this will bring in terms of emission levels. Some of this will contribute to P2/6 security standard compliance and may therefore defer reinforcement. Techniques such as inter-tripping would, at the cost of some operational developments, allow more MW of DG to connect without the need to reinforce the system. This will lead to lower cost DG connections than would otherwise be the case. We expect that, in areas where connection of further DG is difficult, there will be more willingness on the part of developers to engage in trial "active management" schemes rather than face an expensive reinforcement, whose costs will, to some extent, be reflected in their "shallowish" connection charge.

Assessing Costs

Cost Normalisation

As Ofgem are aware, we do not support the use of total costs as an indicator of efficiency because of the inherent difficulties in adjusting for capex inputs and outputs, given the limited degrees of freedom in the statistical analysis. In particular, it will not be possible to arrive at a measure of capital consumption which adequately:

- takes account of the different states of the networks at privatisation;
- which reflects the differing capex spends in the 1980's as a result of differing External Financing Limits; or
- which reflects the many additional drivers for capex other than numbers of customers or length of line.

In terms of general capex, we do not believe that efficiency can be benchmarked on a per customer/km basis given the legitimate reasons for large differences across DNOs (including quality of supply and historic spend) and limited degrees of freedom in the statistical analysis. Instead, efficiency has to be judged by means of a rigorous assessment of each company's investment policies.

We do, however, support the assessment of operating costs with fault costs including capex. It is apparent that DNOs have differing approaches to categorising which costs are classed as "fault costs" and which are not. It is also clear that DNOs have differing approaches to capitalisation. These differences are evidenced by the low R-squared term (42%) in regressions based on operating costs excluding fault costs. We do not believe that the "normalisation" work will ever be able to adjust for all of these differences and, as a consequence, we support the use of controllable cost plus total (i.e. opex plus capex) fault cost as the basis for the efficiency assessment. We also note that this approach produces a very high R–squared term of 80%.

With regard to opex there is a significant risk that the more that costs are disaggregated the less the comparability or "fit" between the companies. The reason for this is that at each lower level of costs, differing accounting policies (e.g. overhead allocation) have a greater impact. We continue to believe that DNOs are essentially the same businesses and therefore to compare Controllable costs, including total fault costs, on an adjusted customer basis as was used in DPCR3, is a robust methodology.

We believe however, that account needs to be taken of the higher costs per customer associated particularly with operating in the remote North of Scotland, and to some extent operating in and around London. We do not believe this was adequately reflected in the allowance at DPCR3 and we will be writing separately on this.

Review of Actual Costs

- *Related party transactions*. If internal margins are to be removed to compare efficiency, it would be necessary for an allowance to be added back in for the purposes of setting allowed revenue going forward.

- *Fixed operating costs*. We would estimate that fixed costs lie toward the lower end of the £14m-£22m range and that the upper limit of the range is artificially high due to the failure to take sufficient account of the higher cost per customer of operating in Scottish Hydro Electric Power Distribution's area, as mentioned above.

Bottom-up Modelling

We have one major concern here, related to the point made above about data becoming less comparable the more it is disaggregated. There is a significant danger of adding together a series of benchmark costs such that a "virtual" DNO is created that is perceived as "best in class" on all cost categories, but in fact, all that Ofgem would be capturing is differences in cost allocation between the various cost categories that Ofgem requested DNOs to use in reporting the data. Due to this measurement error, in our view frontier benchmarks cannot be used with such a disaggregated approach because of the resultant unreliability of the data.

Top Down Analysis

We have provided our views on cost categories, benchmarking techniques and total costs above. However, we would wish to make the following additional observations.

- *Frontier or average costs*. We have repeated above our strong reservations about the incentive properties of the frontier cost methodology and continue to support the use of "average costs". We have also attached a detailed paper supporting this view. In particular, we would urge Ofgem to de-link the benchmarking of current performance (on a frontier basis) from the setting of allowed revenue going forward (on an average cost basis).

- *International and panel data*. It is our experience that obtaining robust and comparable international data is impossible, due to the often vastly different conditions in which oversees companies operate and the differing company structures. We would urge Ofgem not to divert resources away from other more important areas of work.

  We do not believe that the inclusion of panel data i.e. the use of previous years to 2002/03, will aid the robustness of the analysis. There is not time, even if it were possible or detailed information available, to carry out a robust and acceptable normalisation of prior years. For example, different regulatory accounting guidelines were used in earlier years.

- *Inclusion of quality of supply in the analysis*. We do not believe it is realistic or practicable to include quality of supply in the analysis. Quality of supply is subject to separate incentives. There is also a considerable risk that inefficiency could be double-counted i.e. the cost regression already picks up the higher costs associated with higher levels of faults and associated CIs/CMLs. How also would account be taken of the time lag between capex and observable improvements in quality?

  More fundamentally, we do not believe that there are sufficient degrees of freedom in the statistical analysis to take account of opex, current capex and all the inherent variables that affect quality of supply (topography, historic capex, legacy issues, weather, tree coverage, etc). In addition, quality is much more than CIs and CMLs. In particular, unless any analysis includes a robust measure of network resilience, the inclusion of quality adds no value at all.

Productivity Growth

CEPA's TFP study. We believe that CEPA have significantly overestimated the potential efficiency savings still available. The study appears to be mainly based on historic savings and does not make adjustments for capitalisation and distribution/supply split. We will submit a more detailed response after CEPA's presentation on this subject in March. More generally, however, we are concerned about the use to which this information will be put. In particular, it is important to recognise that TFP relates to the industry or average DNO and should not be applied to the frontier.

<u>Mergers</u>

It is still not clear to us how Ofgem intend to avoid double-counting of merger savings.

- *Continue to reduce revenues by £12.5m p.a. (in 1997/98 prices) for each merger.* At DPCR3, there was no indication that the £12.5m deduction from allowed operating costs would continue past the price control period. It was expected that this would be taken account of in the efficiency regressions at DPCR4. This expectation is also consistent with the comment applied to subsequent mergers that merged companies would be expected to be on the efficiency frontier at DPCR4. Now that the majority of DNOs have merged, the efficiency regression will automatically recover merger savings and therefore it makes no sense to us to continue to deduct £12.5m from the allowed costs of the merged companies. In any event, the £12.5m was an amount equivalent to half a fixed cost at that time and Ofgem have recognised in this document that this is clearly a much lower number now.

- *Deduct merger savings to offset the loss of a comparator.* It is not good regulatory practise to retrospectively apply this principle to mergers that happened before the principle was established. Companies could not have factored this into their merger decisions. With regard to those companies that have had this revenue reduction applied, once the £32m one-off payment to customers has been recovered (spread over 5 years), then noted above merger savings are no different to any other saving and are revealed in the cost efficiency regression.

In our view, there is no need to make any merger adjustment other than, possibly, to adjust the costs of the sole non-merged company (in 2002/03) i.e. Aquila.

<u>RAV Roll Forward</u>

We firmly believe that, whichever policy is adopted by Ofgem, it should apply equally to all DNOs, irrespective of the claimed interpretation of the last price review.

Financial Issues

<u>The Financial Ring-Fence</u>

- *Proposal not to strengthen the financial ring-fence.* We see no reason for setting a maximum gearing level or for strengthening the credit rating requirement. In particular, we would agree with Ofgem that companies must be allowed the flexibility to put in place the most efficient financing arrangements appropriate to their circumstances. We also agree with Ofgem's view that this is for the market to decide.

- *Contingent 'cash lock up' mechanism.* For the reasons set out in the paper, we would support a mechanism of the type put forward by Ofgem.

The Cost of Capital

- *CAPM / forward looking data v historical data*. It is clear that against the background of significant additional investment requirements during the next price control period, the cost of capital allowed by Ofgem will be vital for incentives for DNOs to undertake that investment. We believe that unless the cost of capital is set at an appropriate level, shareholders will simply not be prepared to deliver the capital necessary for these investment programmes.

  To that end, it is clear that the CAPM methodology is particularly sensitive to the underlying assumptions and hence can produce a wide range of possible outcomes. We would therefore urge Ofgem to avoid placing too much emphasis on backward looking academic studies, which in our view historically underestimate the cost of capital. In particular, it will be important that Ofgem fully take into account the cash position of DNOs going forward.

- *Embedded debt*. Embedded debt costs are no different to any other sunk cost, incurred prudently at the time. There will be a cost to re-financing debt and DNOs must either be allowed the cost of historic debt or the costs of re-financing. This last point should not be underestimated. Many DNOs as well as other regulated businesses in water, railways and elsewhere in energy will be cash negative during periods of heavy infrastructure investment programmes. They will all be seeking to raise finance from the same capital markets. Such demand will increase costs and if no allowance is made of embedded debt these pressures will be exacerbated.

- *Pre-tax or post-tax approach*. We remain in support of moving to a post-tax approach, with an ex-ante allowance for expected tax liabilities. For the reasons set out in previous correspondence, we believe that this is not only the preferred methodology to recognise the changes in tax allowances, without increasing risk, but also maintains incentives on DNOs to manage their tax positions efficiently. We also agree with Ofgem that an industry-wide post-tax cost of capital should be applied, rather than individual company numbers.

- *Gearing*. We would be firmly opposed to a change in the assumption of 50% gearing in deriving the cost of capital. In particular, the use of higher levels of gearing will simply mean that over time companies will converge on the new assumed level, and that gearing levels will rise. This "ratchet" effect will undermine the incentive to seek out the efficient level of gearing. It will also exacerbate any concerns about DNOs' ability to finance their investment programmes going forward. Finally, we do not consider that it is appropriate to take into account upstream guarantees in calculating the average gearing and hence the 70% figure quoted by Ofgem overstates the actual position. We do, however, agree with Ofgem that a single gearing assumption should be used for the industry in setting an industry-wide cost of capital figure.

Financial Modelling and Indicators

- *Financial model*. Our comments on the financial model were presented at the workshop on 28 January and were captured in the notes of that meeting. Our main concern is that the incentive schemes have been included as costs within the NPV calculation. In our view this is inappropriate as these will then influence the financial ratios output from the model. The financial viability of companies should be assessed before the incentive schemes. Additional reward under these schemes should be additional, not a requirement to meet the financial ratios.

- *Financial indicators*. We note the list of indicators Ofgem intend to use, but we are unclear exactly what purpose these indicators will serve in setting the price control. In particular, how will the set of financial indicators tie in with the "building blocks" approach (allowed capex, plus opex, plus cost of capital times RAV) to setting revenue allowance. For example, the financial model provides no indication about how they will influence the process, which implies they will be used as a "sense check" only. Just to be clear, we support the use of the indicators listed, but we would welcome clarification from Ofgem about how those indicators will be used in the process and the specific values that Ofgem consider appropriate.

Treatment of Pension Costs

There are five main issues on pensions and we comment on each in turn below.

- *The Allocation Between Price-Controlled and Non-Price-Controlled Activities*
  We agree that there is a need to split liabilities of the distribution businesses from the liabilities of the non-regulated businesses. In practice, it is not possible to split employees and liabilities accurately, as records do not always exist about past employment. However, estimates can be drawn from the data that is available and comparison across the industry can give assurance about the validity of those estimates. On this basis, we estimate that approximately 80% of the liability for the deficits falls upon the distribution business.

- *The Treatment of Over/Under Provision*
  As above, we understand the logic for an adjustment for over/under provision of pension contributions compared to the allowances at the last price control. However, it is not clear what was allowed in DPCR 3 for pension contributions. An allowance could be inferred for each DNO from published data but DNOs were allowed neither their own costs nor the costs of the average DNO. Rather, future cost allowances were based on the frontier costs as set by two DNOs, one of which was on a pension contribution holiday and therefore had no pension contribution costs. This suggests that the derived pensions allowance used in calculating any over/under provision should be based on the average "allowed" pension costs of the two frontier DNOs. Otherwise, the frontier methodology at the last review (and relative positions of the DNOs) will be undermined.

In addition, in comparing actual contributions with any derived allowance, Ofgem must take into account the pension contributions actually being made by DNOs in the years up to 2005. Contribution rates of 15 to 20% of salary are currently being made and, in our view, at this level the cash injected into schemes during DPCR3 will outweigh any value Ofgem may assert was included in the DPCR3 settlement. Any under/over provision should therefore be two-way, with DNOs receiving additional cost allowances post 2005 for over-provision.

- *The Treatment of Early Retirement Deficiency Costs*
  We would be particularly opposed to any adjustment in respect of early retirement deficiency costs. Pension scheme rules have been unchanged since privatisation and under protected persons' legislation these rules cannot be changed to the detriment of the members. Use of surplus is in some cases defined in pension scheme rules and in any event is not in the sole gift of the companies: actuaries, trustees and independent trustees have a say.

  Some surpluses were irrecoverable, i.e. there could be a permanent pension contribution holiday and the surplus would remain. It would have been incorrect to allow such surpluses to continue to grow. There are Inland Revenue limits on the allowable size of a surplus and surpluses cannot be allowed to breach those limits. We would therefore reject any suggestion that DNOs have used past surpluses inappropriately in incurring early retirement costs.

  It is also clear that customers have benefited from the redundancies that have given rise to these early retirement costs. Companies shed staff using the pension scheme surpluses to meet part of the cost. These staff reductions resulted in cost savings that OFGEM have ensured, and will continue to ensure, are enjoyed by customers. Yet customers have not paid for these savings, as there was no allowance for pension costs associated with redundancy in past price controls. Accordingly, if these costs are in some way retrospectively "disallowed" by Ofgem, DNOs would retain significantly less that the target 25% of the NPV of past efficiency savings. This would undermine incentives to reduce costs going forward.

  In summary:

  - The costs incurred by the Schemes were efficiently incurred;
  - Customers have seen and will continue to see benefits arising from these costs and customers ought therefore to bear these costs; and
  - Customers have not already borne these costs as no allowance has been made in previous controls.

- *Schemes in Surplus*
  We believe that, following the valuation this summer, some DNOs schemes may be in surplus. Since these DNOs will not be making a claim in respect of past deficiency costs, we do not believe that the proposed rules in relation to over/under funding or early retirement deficiency costs should apply to these schemes.

- *Retrospective Adjustment*
  Ofgem have suggested that the rules on over/under funding and early retirement costs would apply right back to privatisation. Our general views on these issues notwithstanding, we would be firmly opposed to *any* adjustment for years before the current price control period. Concerns about this approach include the following.

  i) Adjustments in respect of years before 2000 would be based on arbitrary allowances. As noted above, it will be difficult enough to derive pension cost allowances for the last review. We therefore believe that it will be impossible to derive figures for years prior to 2000 and hence any "allowance" derived by Ofgem will be arbitrary.

  ii) This would raise significant issues of regulatory risk and investor confidence in the stability of the regulatory regime going forward. To Ofgem's credit, it has hitherto avoided retrospective regulation where possible (e.g. the RAV has been consistently calculated from one price review to the next). That reputation would, in our view, be undermined if over/under provision or early retirement adjustments were made for years prior to 2000.

  iii) It would also damage incentives to reduce costs going forward. Indeed, it is clear that a number of the new incentive schemes that Ofgem are developing for the current review require confidence in the regulatory regime going forward. For example, the five year retention mechanism for opex and capex efficiency savings, as currently proposed, requires DNOs to have confidence that they will indeed receive the flagged-up reward for efficiency in the 2010 review. Similarly, the hybrid mechanism for distributed generation requires DNOs to be remunerated for investment over 15 years. We firmly believe that these new schemes will be undermined if Ofgem, in effect, re-open the 1995 review and the privatisation settlement by making adjustments for early retirement costs and under/over provision back to 1990.

APPENDIX 1

The Incentive Properties of the "Average Costs" Methodology

Introduction

1. In determining the revenue each company needs to cover its operating costs, Ofgem will need to consider two questions:

   - How quickly should efficiency savings be passed on to customers? and

   - How should companies be incentivised to continue to seek out efficiency savings, especially when those savings are becoming harder to find?

2. As Ofgem have recognised in the work on incentives, these questions are linked and (potentially) conflicting. It is also apparent that these issues do not arise in a competitive market.

3. In DPCR3 Ofgem introduced the "frontier" costs approach to assessing operating cost efficiency and projecting future costs. This paper argues that this approach has significantly weaker incentive properties than the "average" cost methodology used in previous price control reviews, and which better mimics a competitive market.

Background

4. The "frontier" costs methodology was introduced on the premise that companies had to be allowed their own costs at the start of the price control period, and that companies not on the frontier should be allowed a catch-up period ("glidepath"). These companies were allowed four years to catch up 75% of the way to the frontier. Presumably the 25% discretion was to allow for perceived uncertainties and inaccuracies in the estimation of the frontier.

5. The frontier was not expected to improve over the price control period, but remained at the 97/98 level of base costs for the frontier companies. However, it can be argued that this represented no reward comparatively for the efficient companies in recognition of their frontier status and hence did not provide any incentive for those companies to further strive to improve efficiency during the next price control period. The glidepath that was introduced for the "laggards" provided a generous grace period before those companies were required to achieve frontier performance. In effect, therefore, the glidepath approach provided the inefficient companies with the opportunity to gain benefits from efficiency savings that were not available to the frontier companies that had already achieved those savings. This produced a further disincentive to efficient companies to continue to drive the frontier forward.

6. Ofgem made a token recognition of frontier performance by allowing at a late stage in the review an arbitrary 1% additional allowed revenue to the three companies on or near the frontier, for the duration of the price control. Not

only was this not symmetric with the benefits available to the laggards but such "within range" adjustments are not consistent with Ofgem's declared aims of transparency and predictability of regulation.

7. It is noted that the importance of rewarding the frontier companies has been recognised by OFWAT in the current price control review in the water industry. This is particularly important, since it is the performance of those companies that determines the price control outcome for the whole industry and hence all customers.

8. Ofgem have since committed to an additional fixed retention period for opex savings made after 1 April 2003, ostensibly to solve a perceived periodicity problem. However, it can be argued that this mechanism alone will not completely resolve the periodicity problem. In particular, as long as a company's allowed future costs are dependent on past performance there will always be a residual incentive to consider the effect on future allowances of delaying individual efficiency improvements.

9. Ofgem also assert in the July consultation paper that the application of fixed retention periods on their own will not weaken incentives on companies that are at the frontier. As noted above, the glidepath adopted at the last price review rewarded inefficient companies by providing them with additional revenue for failing to achieve the standard of the frontier companies. The fixed retention period works in the same way as the glidepath and there is a real danger that it will further reward those companies in contrast with the frontier companies.

10. This arises because there is significantly more scope for the inefficient companies to reduce costs compared to companies that were at the frontier at the last price control review. Indeed, as noted above, the frontier approach at the last price control review only required those companies to achieve three quarters of the difference in cost with the frontier companies over the price control period. There is thus a greater prospect for additional returns for less efficient companies under the fixed retention period than for companies that have made identical savings earlier in the regulatory cycle. As above, this reinforces the poor incentive framework for frontier companies.

11. However, the fixed retention period for operating cost savings is welcome, particularly given the fact that the marginal investment necessary to achieve future savings is likely to be much greater than in the past. This paper argues that this cannot be combined with a frontier costs approach but that this methodology should be supplemented by an average cost approach to setting future operating costs allowances. Otherwise, elements of the periodicity problem will remain and incentives on the frontier companies will be weakened further.

<u>The "Average" Costs Methodology</u>.

12. The benefits of competition depend on reward for winning and penalty for losing. Those companies that are efficient survive, those that are not make

low returns and have their management replaced. This creates an ongoing pressure to maximise efficiency.

13. Under competition, prices are set by the market and individual firm's costs have a negligible impact. A drop in prices only occurs if all companies reduce their costs. A firm will always be better off than it would be without the cost reduction and will keep the benefits until its rivals catch up. This can be contrasted with the frontier costs regulatory approach, whereby if a company performs well it receives a tougher target (i.e. the "ratchet" effect).

14. Under the average costs methodology, a company's allowed costs are based on the industry average for a firm of their size (this has been arrived at in the past by regression analysis, although there is no reason why other suggested statistical techniques should not be used to find the average as well as the frontier). This better replicates how a competitive market works, by relating operating cost allowances to factors that are, as far as possible, exogenous to the individual company's past performance.

15. Under this approach, since no individual company could be expected to materially affect the industry-wide regression line (i.e. the average), there is no incentive to delay efficiencies. An average cost approach would thus resolve the periodicity problem and the regulator would no longer have to worry about the speed of transfer of efficiency savings to customers. It would also mimic the outcome of competitive markets where companies with lower than average costs receive higher returns and vice versa. Such an approach would therefore provide the strongest possible incentive on all companies to reduce operating costs.

16. Basing allowed costs on the industry average would also be consistent with an industry cost of capital (i.e. set for the average company). An inefficient company would earn a return less than the cost of capital for as long as they under-performed the average.

17. In aggregate the use of average costs produces the same allowed cost for the industry as the total of companies actual costs, with the added benefits that customers pay the same whether served by an efficient company or an inefficient company. An average cost approach would also avoid benchmarking against the frontier, which was heavily criticised at DPCR3.

18. The rolling opex incentive "bolted on" to the average cost methodology would then provide a catch-up mechanism and link back to companies' actual costs at the start of the period, replacing the glidepath.

19. The benefits of the average costs approach were also recognised by Ofgem's consultants Frontier Economics. In their report they point out that companies will eventually reveal the efficient level of costs through the level of profits made. However, assuming that companies have differing levels of efficiency, they argue that benchmarking provides additional information about how far costs can fall and therefore allows earlier price reductions. If benchmarking is based on the average, then as we have also argued above, a company should

not be worried about reducing costs and benchmarking because the change in its own costs does not affect the average.

To illustrate this, Frontier calculate that under a five year fixed retention mechanism a company keeps 29% of its opex efficiency savings. The proportion retained increases as the number of firms increases, for example with 14 companies the retention is 29% + (71%*13/14) = 95%, because under an average costs methodology a company's own cost reduction is weighted by 1/14 when calculating the industry cost reduction.

The attraction is that all firms face this same high incentive, however the incentive power has increased without reducing customer benefits. For example, if they all make the same cost reductions then each firm's price falls at the price control review by the full amount of the cost reduction, and customers receive the full 71% of the benefit.

Conclusion

20. We have discussed above the strong incentive properties of an average cost approach to setting operating cost allowances, which in our view should be used to supplement the five year retention period. There is a real danger that alternative approaches, including a repeat of the frontier methodology adopted at the last price review, will significantly blunt incentives for the efficient companies to constantly strive to reduce operating costs. We would therefore urge Ofgem to commit to the use of an average cost approach at the earliest opportunity, with subsequent discussions about the detailed approach to setting the average line following the work by Cambridge Economics.

APPENDIX 2

Analysis of Minimum Return under Ofgem's Proposed DG Incentive

Ofgem's approach considers an investment of, say, £100m. If the proportion covered by the incentive element of the scheme is 20%, 80% of the investment will be RAV funded.

On an annuity basis, the spreadsheet function PMT(6.5%, 15, 80) gives £8.51m as the fixed annual revenue required over 15 years to fund an initial investment of £80m at the cost of capital of 6.5%.

If this revenue represents the total return on the £100m investment (i.e. no revenue from the incentive element at all – the "worst case" position), the spreadsheet function RATE(15, -8.51, 100) shows the effective rate of return is 3.22% as in Ofgem's paper.

However, for RAV funding, the revenue is generated in a profiled manner – being given each year by the depreciation plus a 6.5% return on the net book value of the investment: a total revenue which declines year on year. This can be modelled as follows:

RAV funding		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Opening RAV		80	74.67	69.33	64	58.67	53.33	48
Depreciation		5.33	5.33	5.33	5.33	5.33	5.33	5.33
Closing RAV		74.67	69.33	64	58.67	53.33	48	42.67
Return		5.2	4.85	4.51	4.16	3.81	3.47	3.12
cash (dep'n + return)	-100	10.53	10.19	9.84	9.49	9.15	8.8	8.45

	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Opening RAV	42.67	37.33	32	26.67	21.33	16	10.67	5.33
Depreciation	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33
Closing RAV	37.33	32	26.67	21.33	16	10.67	5.33	0
Return	2.77	2.43	2.08	1.73	1.39	1.04	0.69	0.35
cash (dep'n + return)	8.11	7.76	7.41	7.07	6.72	6.37	6.03	5.68

Using the spreadsheet function IRR on the final "cash" line of the above investment profile gives a value of 2.85% as the "worst case" outcome of only receiving pass-through income on 80% of the value of an investment. 0.85% can be modelled in a similar manner as the "worst case" outcome for a 70% pass-through scenario.