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Dear Cemil,

Electricity Distribution Price Control Review – Initial Proposals

Thank you for the opportunity to comment on the above paper. Our detailed comments on the issues raised in the initial response are set out in the attached paper. There has been much progress on the review since the last paper in March. In particular, we welcome the clarity provided on, amongst other things, depreciation, opex allowances, capex incentives and the use of RPI. There are however many other areas of the review that require further work and we have highlighted those in the attached paper.

In our view, the top five areas that Ofgem need to focus on are as follows.

(1) Cost of capital

The relevant number to focus on is the traditional post-tax cost of capital. The so-called "Vanilla" cost of capital is confusing and is in any event simply a modelling device. Similarly, the pre-tax cost of capital is also not directly relevant because of the changes to the tax rules. Indeed, we believe that the Vanilla concept significantly complicates the process and could usefully be abandoned in the interests of transparency and consistency.

We firmly believe that efficient companies should be capable of earning more than 6% post-tax real. Assuming that there is scope for such companies to outperform the price control by 50-100 bps (which there is not at present), then a minimum cost of capital of at least 5.25-5.5% is inferred. In our view, a post-tax WACC in the range of 5.25-5.5% can be justified by the academic evidence, as well as an assessment of the requirements of equity investors. In any event, we would urge Ofgem to provide clarity on this issue in the September update.

(2) Tax

We are still unable to replicate Ofgem's tax calculation. It is nevertheless apparent that this is a serious concern and we believe that Ofgem have significantly underestimated SSE's tax bill.

It is therefore clear that much work remains to re-calculate the tax allowances for all of the DNOs. We are concerned that there is not much time to deliver that work in this highly technical area before final proposals are brought forward by Ofgem. Moreover, it is also apparent that some uncertainties exist about the exact nature of tax allowances going forward and this makes it difficult to finalise ex-ante allowances for each DNO.

It may therefore be necessary to consider a form of pass-through of tax costs, at least for the next price control period until there is greater certainty about how the new tax regime will work in practice. Clearly in considering any such arrangement incentives to ensure continued tax efficiency will be paramount. However, we believe that this could be achieved by clearly flagging up now that any inefficiently incurred tax costs between 2005-2010 risk being disallowed at the next price review, possibly coupled with the prospect of additional rewards at the next price review for those that can demonstrate tax cost efficiency. This would be sufficient to ensure that any pass-through of tax costs would not undermine tax efficiency on the part of the DNOs.

(3) Capex and Quality of Supply

We have serious concerns about the proposals for quality of supply and therefore cannot support any increase to revenue exposed under IIP or the other elements of the quality of supply package until these concerns have been resolved.

The IIP targets and the overall quality of supply package are clearly linked to the allowed capex. In SEPD's case in particular the targets as proposed are unacceptable, given the capex allowed. We firmly believe that either the target setting methodology should be re-visited to reflect the allowed capex <u>or</u> CML and CI targets should remain as proposed in the paper, but Ofgem should allow the quality of supply capex we submitted in our FBPQ. We also believe that the level of risk inherent in the quality of supply regime needs to be re-assessed.

(4) Operating cost allowances

We are broadly supportive of the overall framework for setting operating cost allowances. In particular, we continue to support an approach based on the use of 'controllable costs' plus total fault costs. We also believe that, given all DNOs are essentially the same businesses carrying out the same activities, the regression is reasonable statistically.

We also welcome the (partial) recognition for setting the frontier that the use of the upper quartile implies. However, this benefit is removed by assuming an ongoing efficiency assumption from 2005/06 of 2% p.a. We do not believe that there is any justification for this assumption. Indeed, while we included in our FBPQ an ongoing efficiency target of 2% p.a., this is an internal target set against a background of costs rising year on year. We also forecast several specific cost categories that were due to rise. Ofgem have ignored these cost increases, but have "cherry-picked" the 2% efficiency assumption from our BPQ.

In our view, it is not reasonable both to disallow future cost increases and to make the ongoing efficiency assumption. In effect, we have been set a 4% p.a. efficiency factor, not 2%. This undermines incentives to be at the frontier in future. It is also clear that this is a very challenging target for the company at the efficiency frontier to achieve. Indeed, we note that Ofgem's efficiency consultants Ernst & Young state in their report on SSE: "We do not believe that there are further substantial operational efficiencies to be achieved over the five years of DPCR4"

As a consequence, we believe that Ofgem should either recognise, in full, the cost pressures as indicated in our FBPQ or remove the 2% efficiency assumption.

(5) Incentives

We remain strongly opposed to the proposal to align incentives to reduce operating costs and capex. For the reasons set out in our response to the March document, we continue to believe that this is unnecessary and would significantly weaken incentives for operating cost efficiency.

In addition, the Initial Proposals do not provide any detail of the mechanics of the proposal. This leaves little time for consultation about the detail of such a fundamental reform to RPI-X regulation. Indeed, we would regard it as poor regulatory practice to introduce substantive new reforms so late in the regulatory review. We also believe that it will be very difficult to finalise a robust price control within Ofgem's proposed timetable if there is a major re-allocation of costs into capex.

As a consequence, we would urge Ofgem in the strongest possible terms to retain the existing incentive structure for operating costs and instead focus on finalising the RAGs before publishing final proposals in November.

I hope that you find our comments helpful. We would be pleased to discuss any of the views expressed.

Yours sincerely,

Rob McDonald
Director of Regulation

Chapter 3 – Form, structure and scope of revised price controls

Form of the price control

Revenue driver

Ofgem propose that for the next price control period there will be no volume driver attached to EHV revenues. We would broadly agree that the costs of existing EHV sites are captured within the initial connection cost and therefore, *for existing sites*, there is no need for a separate EHV revenue driver. However, the Initial Proposals do not mention the treatment of *new* sites between 2005-2010. Our understanding is that revenue from these sites would continue to be treated as an excluded service during the 2005-2010 period. We would support that approach and would therefore welcome confirmation that this is indeed the case.

Tariff basket weightings

The revised weightings set out in the document for each voltage category seem broadly reasonable.

Price index

We support retaining the use of RPI for the reasons set out in the paper. We also welcome the fact that Ofgem have clearly set out their policy on this issue early in the process, which has removed a major uncertainty about the new price control.

Scope of the price control

Units distributed out of area

We welcome the proposed treatment of units distributed on independent networks. The proposals strike a reasonable balance between encouraging competition and protecting customers by treating competitively won out-of-area networks as excluded services, but applying a relative price control to the prices charged to customers on such networks.

We do however have a concern about the application of a relative price control to embedded networks within DNO areas that may be subject to a large Po cut. Clearly in these circumstances, the embedded network developer is exposed to significant regulatory risk and in some cases could see a significant cut in income that was not budgeted for in tendering for the work.

We would therefore urge Ofgem to apply a “glidepath” to the relative prices of embedded networks in such circumstances. This would ensure that the effect of such large, unforeseen, income cuts is phased in over a period of time, providing the embedded network developer time to adjust to those new circumstances.

We also believe that the relative price control mechanism should provide price stability for new network developers over the lifetime of the assets. This has been achieved in the case of independent gas networks by, in effect, fixing the relative price control for 20 years. We believe that a similar mechanism should apply in electricity.

Business rates

We welcome the clarification that Ofgem do not intend to disallow any rates costs. We believe we have negotiated the best outcome we are able to on formula rates and have achieved significant reductions from the levels first proposed. We have written to Ofgem separately on this with details of the negotiations with the VOA. Ofgem's conclusion is therefore appropriate and the alternative would result in significant risk (and likely higher bills) for both DNOs and customers.

Hydro-benefit

We welcome the mechanism put forward by the Secretary of State to provide a payment to the distributor with highest costs, which is funded by transmission charges on all suppliers. Clearly the price control will need to reflect this and we think this is easy to achieve. In particular, we believe that the simplest approach would be to set the price control allowed revenue in the normal way, as for all DNOs, and to reflect the resulting aggregate allowed revenues within the main price control formula (again exactly as for the other DNOs). This could then be supplemented by a new licence condition which makes it clear that the amount of revenue that will be recoverable from customers will be the allowed revenue under the formula less any amount *actually* paid to Hydro-Electric Power Distribution by the GB system operator.

This would ensure a full and timely pass-through to customers of any subsidy mechanism. We would be opposed to an alternative approach based on an ex-ante forecast of any such subsidy. Such an approach would risk windfall gains or losses for customers or the DNO, depending on the difference between the actual amount of the subsidy and the forecast at the time of setting the price control. This would clearly be inconsistent with the policy intent of the new subsidy mechanism.

Revenue protection

It is apparent that under both the present and proposed price control, DNOs' allowed revenue is in part determined by the volume of units distributed. In addition, DNOs can earn higher revenues under the losses incentive term if theft is reduced and those incentives have been strengthened as part of the price review. As a consequence, we consider that there are already adequate commercial incentives on DNOs to minimise theft. We would therefore be opposed to a revenue protection "obligation of last resort" being placed on DNOs.

However, given the development of differing arrangements in the competitive supply market, it may be appropriate to consider treating revenue protection as an excluded service. This would encourage DNOs to provide a revenue protection service that is more responsive to suppliers' requirements as they evolve over time. It is also clear that suppliers always have the option of carrying out their obligations using alternative service providers (including themselves), should they wish to do so. This would ensure that any revenue protection charges are reflective of the service provided.

Allocation of costs for the incentive mechanisms

We remain strongly opposed to the proposal to align incentives to reduce operating costs and capex. For the reasons set out in our response to the March document, we continue to believe that this is unnecessary and would significantly weaken incentives for operating cost efficiency.

In addition, the Initial Proposals do not provide any detail about the mechanics of the proposal. This leaves little time for consultation about the detail of such a fundamental reform to RPI-X regulation. Indeed, we would regard it as poor regulatory practice to introduce substantive new reforms so late in the regulatory review. We also believe that it will be very difficult to finalise a robust price control within Ofgem's proposed timetable if there is a major re-allocation of costs into capex.

We also do not accept Ofgem's conclusion that "the development of robust definitions is not achievable by final proposals in November". This seemingly is Ofgem's only argument for the change in the treatment of costs. We have already committed to working with Ofgem to finalise the RAGs. Indeed, now would seem the ideal time to finalise the RAGs, with the recent experience of the cost information collected as part of the DPCR4 cost normalisation process. To delay this post-April 2005, as has been suggested, risks losing key staff from Ofgem and the DNOs who may move on to other work after the price control review. In any event, DNOs need precise definitions of what is included in the price control (i.e. exactly what is included in each of the "capex" and "opex" pots) and what is not, before they can reasonably be asked to accept the final proposals. As stated above, we firmly believe that this is achievable by November, building on the work that has been done already in this area.

As a consequence, we would urge Ofgem in the strongest possible terms to retain the existing incentive structure for operating costs and instead focus on finalising the RAGs before publishing final proposals in November.

Dealing with uncertainty

The Initial Proposals recognise two areas where significant cost uncertainty exists: costs arising from the Traffic Management Act; and the Electricity Supply Quality and Continuity Regulations (ESQCR). A re-opener and limited re-opener respectively are suggested to address these issues. While we welcome this recognition, we would wish to add two further areas which we do not believe fall within the normally recognised scope of the price control. These are:

- **Costs arising out of the Customer Transfer Project (CTP).** At the request of Ofgem/Energywatch the industry is presently undertaking a major review of the customer transfer process. We do not believe that this review should result in significant industry-wide IT systems development. In particular, we continue to believe that real improvements in customers' experience of the transfer process can be achieved with relatively modest reforms coupled with adoption of best practice in all suppliers' processes. However, it is also apparent that some solutions being considered by the customer transfer project would involve significant systems development, such as a substantive reform of the way data is stored. It is therefore possible that as a result of the CTP, DNOs will have to make one-off substantial and costly changes to IT systems. As those costs are uncertain both as to if they will arise and how much they will be (if any), then they should be treated in a similar way to that proposed for Lane Rentals and ESQCR;

- **Taxation**. As a result of the discontinuing of the Non-Load Agreement and the switch to a post-tax cost of capital, the Initial Proposals arrive at a tax allowance which we are unable to replicate, and which does not allow recovery of our expected tax payable. This may be simply a calculation difference, and we provide further details of where we think our calculations and Ofgem's are different in the Financial Issues section below. We recognise that Ofgem are (rightly) concerned about the incentives on DNOs to manage their tax affairs efficiently and that tax allowances should not be overly generous. However, the size of the difference between Ofgem's calculation and ours means that tax is a serious cause for concern. We therefore suggest that consideration should be given to treating tax as a part of the mechanism for dealing with uncertainty.

With regard to the mechanism itself, the Initial Proposals propose re-openers but with no detail of the licence modification or how these re-openers would be triggered or would operate. Reference is also made to the proposal made by the DNOs through the ENA for a formal mechanism, including draft licence conditions. We continue to regard such a mechanism as being in both the DNOs' and Ofgem's best interests, and that the ENA proposal is consistent with Ofgem's proposal for the treatment of ESQCR and line rentals cost. The DNOs have considered Ofgem's concerns with the original proposal and the ENA submitted a further letter on 22 July, which addressed these issues. We strongly endorse that letter.

To summarise, we would urge Ofgem to adopt in full the DNO's proposed licence conditions for dealing with uncertainty. We have also explained above why we believe that consideration should be given to including industry cost relating to the Traffic Management Act, ESQCR, industry sponsored change to IT systems and tax within the scope of such a mechanism.

Losses

We have generally supported the basic mechanics of Ofgem's proposed revised incentive scheme for distribution losses. A number of detailed changes and clarifications have been made since the publication of the March consultation document and we have also had the opportunity to review Ofgem's thinking on the setting of actual losses targets.

Against this background, we still have a major concern about how the expected upward pressure on losses due to the connection of certain types of DG in the SHEPD area will be dealt with under the revised arrangements. We are also not comfortable with the target setting calculations for this DNO area and have written separately to Ofgem on this issue. Furthermore, we have some comments on the new information that Ofgem has made available on the setting of the losses incentive rate. We set out our comments on these and other relevant issues below.

Distributed Generation Adjustment

We note that Ofgem has increased the level of the proposed "LAF floor" which is intended to limit a DNO's exposure to the DG contribution to increased distribution losses. This provides a better balance between the losses incentive and the DG incentive schemes, but we continue to advocate that the LAF floor should be set such that there is still some expectation for the DNO of an overall benefit from DG schemes that increase losses. Between the combination of the level of the LAF floor, the setting of targets and contractual measures available to the DNO, there should be scope for DNOs to neutralise the financial effect on the losses incentive of DG which increases distribution losses.

This is particularly important for SSE in the SHEPD area. We have made a number of submissions to Ofgem on the expected effect of some types of DG in this area on overall distribution losses. In SHEPD, LAFs are all set to unity and Ofgem's proposed LAF adjustment mechanism to cater for the effect of DG on losses would not be workable in this area for the reasons we have previously set out. Over the months of development of Ofgem's distribution losses incentive, we have put forward various approaches for dealing with this issue and now consider that an appropriate allowance in the setting of targets is the only realistic way forward for the SHEPD area.

Setting the Incentive Rate

The June paper set out a view that the losses incentive should be valued within a range from £41 to £55/MWh. This contrasts with Ofgem's previous analysis on the cost of losses in its January 2003 consultation, where the range was proposed at 2.96-3.62p/kWh. The January analysis was broadly confirmed in Ofgem's June 2003 initial proposals document, which stated that the value to be presented as part of the price control proposals, was not expected to "deviate significantly from the range of estimates presented …[in] the January document". We are therefore concerned that Ofgem's midpoint proposal of £48/MWh is significantly outwith the previous range and that the proposed level is unnecessarily high. We have the following points on the calculation outlined by Ofgem:

- We recognise the price suggested for the cost of purchasing lost units at £27/MWh but consider that environmental costs are already factored into this price. Ofgem is therefore "double-counting" in adding a further £3/MWh to this figure. In particular, any government figures on the cost of carbon are estimates whereas market prices have already factored in these costs. There is no justification for using anything other than market prices in this respect; and

- The transmission cost element is given a range of between £1 and £4/MWh and distribution costs a range between £10 and £21/MWh. In the previous analysis, transmission costs were given a range between 1.08p/kWh and 0.15p/kWh and a point estimate was made of distribution costs at 0.56p/kWh. There is thus a substantial upward revision to the overall estimate of transportation costs with very little explanation of how these particular figures have been calculated.

In summary, the suggested range and its component seem high to us, and inadequately justified. At this stage in the review process, we would not expect substantially different figures for the incentive rate compared to the range signalled in the earlier documents referred to above.

Other Points

EHV volatility. We continue to advocate that EHV units are excluded from units entering and leaving the distribution system due to the volatility in this volume.

Rolling retention mechanism. We note that Ofgem has amended the proposed mechanism to carry forward incentive payment amounts rather than target adjustments. We agree that this approach will preserve benefits/losses at a consistent incentive rate to that in which the saving/increase in losses was made. We also welcome the clarity brought by the worked examples, but continue to consider that the algebra will be complex. There may therefore be some merit in allowing the present value of the benefit or penalty to be rolled up into a one-off calculation in the year in question, or the following year. We are also not clear about the relevance of the year 2004/05 to the proposed incentive calculations. We would expect the new incentive mechanism and targets to be self-contained within the next price control period.

Proposed targets. In the information that Ofgem has provided separately to each DNO on target setting methodology, indicative targets were set to 2 decimal places. In the price control initial proposals, the same indicative targets are presented to 1 decimal place. We would welcome clarity about whether the final targets will be set at 1 or 2 decimal places as this does have an appreciable impact on the financial effect of the scheme. Perhaps to give a greater degree of granularity, without spurious accuracy, rounding of targets to 0.05% intervals should be considered.

Capital expenditure on losses. We note that Ofgem propose that efficient expenditure related to losses will be allowed in the regulated asset value and welcome this commitment from Ofgem. To give DNOs sufficient confidence to make such investments in the next price control period, the amended criteria for assessing efficient capital expenditure will have to be clearly signalled before the next price control period begins.

Meter Asset Provision (MAP)

We support limiting the price caps to basic domestic credit meters and basic prepayment meters, supported by a non-discrimination approach to other types of meters. We also agree with the statement in Paragraph 3.46 that effective competition provides the best protection to consumers.

We are surprised therefore that the indicative range for MAP price caps shown in Table 3.3 are at a marginal rate which would not encourage new entrants to the MAP market. Indeed, we would question whether suppliers would be able to unbundle

MAP services to third party providers against the background of the MAP tariff caps published in the paper.

We believe that this issue has arisen as a consequence of the traditional "building blocks" approach used by Ofgem to setting the MAP tariff caps. Each DNO's indicative cap is based on marginal meter purchase prices, annuitised over 18 or 20 years. We agree with the period used which reflects the useful economic life of a meter, takes into account early-failure rates and leaves the decision to re-certify or replace to the company. However, assuming that DNOs purchase meters efficiently, basing the MAP cap on the marginal purchase price of the meter would allow no headroom/margin to encourage new entrants to compete in the market.

This general concern is exacerbated by the margin allowed within Ofgem's MAP caps. By basing the allowed margin on the depreciated replacement cost which has been excluded from the distribution price control, Ofgem are in effect only allowing the margin on a part-depreciated meter. Although it could be argued that this is sufficient for existing meters, it does not allow the full return on a new meter. Since DNOs are expected to retain the obligation to provide new meters on request for at least another two years, this is unacceptable. It would also clearly distort competition for MAP services.

We also do not see any reason for the wide differences in MAP allowances across DNO regions. Indeed, we see no justification for regional variation in the cost of purchasing a meter.

As a consequence, we would strongly suggest that the MAP cap should be common to all DNOs and based on the highest price paid by a DNO, plus a margin. MAP "tariff caps" set on this basis would provide a much better balance between encouraging competition and providing a backstop protection for suppliers until Ofgem is sufficiently confident that competition is developed.

Our other main concern with the MAP cap is that we have still not been fully protected against stranding of assets through early replacement of an existing meter. Under current arrangements, if a meter is replaced before the end of its useful life, for example by a new supplier on change of supplier, the DNO can recover the outstanding cost of the meter and its installation through the distribution price control, subject to a reduction in allowed revenue to take into account costs avoided. However, the use of depreciated replacement cost, although reducing the exposure to stranding, still leaves that element exposed to the risk of premature replacement. This leaves DNOs in a worse position than they are currently. In adjusting the main RAV to reflect separation of metering from the main price control, we would urge Ofgem to bring forward proposals which provide DNOs with better protection from stranded assets than the depreciated replacement cost approach.

Meter Operation (MOp)

We are disappointed that the Initial Proposals did not provide enough information on MOp to enable us to judge what our total allowed revenue under the proposals would be (i.e. total distribution and metering).

We continue to believe that competition in MOp is established. Indeed, several suppliers are in process of de-appointing DNOs. However, with regard to the price cap proposals we have serious concerns about the methodology suggested. For example:

- We do not believe it will be possible to arrive at a robust average revenue cap, whether based on the numbers of meters or the number of visits. The drawback with basing the cap on the number of meters (incidentally, we assume this means the number of meters for which MOp is provided, not MAP), is that the workload associated with the average meter varies hugely from year to year. Meter re-certification programmes can vary dramatically, for many reasons, as can the requirement by suppliers for functionality changes. A 'K'-type adjustment would therefore be required each year, which could be significant and volatile and which would, in turn, make the predictability of prices difficult;

- For similar reasons, the number of visits varies significantly year on year;

- We are concerned that the opex costs shown in Table 3.4 are not on a like-for-like basis between DNOs. It can be clearly seen from the table that there is little correlation between the costs and the number of meters; and

- In any case, the metering opex costs in 2002/03, which were before the introduction of transactional charges, have little relevance to MOp costs going forward. Many MOp costs are now recovered directly from the customer on a transactional basis.

We therefore see no reason why similar price control principles could not be applied to MOp as suggested for MAP i.e. apply a cap on a basic service and relate other services to this basic service through the use of a non-discrimination provision. The basic service which we would suggest is used is the installation of a new basic domestic credit meter. Each DNO could readily provide its cost, to which a margin could be applied which would not only provide a return but would also allow headroom to encourage new entrants into the market (i.e. the cap should be set at market rates). It has been suggested that there are market-based contract rates available from those DNOs which have already sold or outsourced their MOp business. In our view, these would have to be considered carefully to take account of any agreements in those contracts which relate to the original sale rather than ongoing business.

The specific methodology for the setting of MOp caps notwithstanding, we are still not clear that DNOs will be allowed to recover their short-term fixed costs, which are stranded through loss of market share. The costs of the infrastructure in place to service the licence 'meter operator of last resort' obligation, are significant. As market share is lost it will not be possible to quickly re-deploy staff or re-utilise buildings and other assets. Indeed, there could be additional costs involved in severance payments. In our view, it will not be possible to arrive at a mechanism through which these costs can be recovered through the metering price control, and therefore the only option is to allow recovery through the main distribution price control.

Definition of a basic service

With regard to the suggestion that a basic service could be defined as that provided at 1 April 2003, it should be remembered that MAP and MOp were not split at that time and therefore only a bundled service was provided. The definition of a basic service should therefore relate to current service provision

One-way door

We welcome the proposal that once a supplier has de-appointed a DNO for a certain class of meter the licence obligation is lifted. However, careful drafting of the licence will be required to define 'de-appointment'. In particular, it would be unacceptable if a supplier were to leave one or two of each class in order that the obligation is retained.

Chapter 4 - Quality of service and other outputs

We have serious concerns about the proposals for quality of supply and therefore cannot support any increase to revenue exposed under IIP or the other elements of the quality of supply package until these concerns have been resolved.

The IIP targets and the overall quality of supply package are clearly linked to the allowed capex. In SEPD's case in particular the targets as proposed are unacceptable, given the capex allowed. We have set out below our detailed comments on the quality of supply package. In short, however, we firmly believe that either the target setting methodology should be re-visited to reflect the allowed capex <u>or</u> CML and CI targets should remain as proposed in the paper, but Ofgem should allow the quality of supply capex we submitted in our FBPQ. We also believe that the level of risk inherent in the quality of supply regime needs to be re-assessed.

Summary of results from the consumer survey

In our view, the consumer survey clearly shows a customer willingness to pay for improvements in resilience, yet the Initial Proposals ignore this. We believe that there are clear and measurable benefits from enhanced resilience, particularly in storm conditions. We therefore included amounts in our FBPQ which we believe represent value for money for customers. We are disappointed that Ofgem has not reflected these amounts in the initial proposals.

Revenue exposure to quality of service incentives

We have a number of concerns with the parameters of the quality of supply package, as summarised in Table 4.1 of the Initial Proposals, which are set out below.

- **IIP**. As noted above, we could not accept an increase in revenue exposure under the IIP scheme unless our issues about the targets and the scheme risks are addressed.

- **Storm compensation**. We see no reason why exposure to storm compensation arrangements is proposed to double. There is no evidence that any change is required, but it is clear that a doubling of the cap would significantly increase risk to DNOs. We are also not aware that the current 1% cap has been hit by any company.

- **Standards of performance**. It is clear that the revised quality of supply package will result in significant additional risk to DNOs to the extent that an overall cap of 4% of revenue is proposed. We support the concept of an overall cap, but we see no reason for excluding other standards of performance from the cap.

- **Quality of telephone response**. In our view, the quality of telephone response incentive serves no useful purpose. However, if Ofgem insist on such an incentive mechanism, we would expect the possible rewards and penalties to be symmetrical. In particular, we do not see any logical justification for making the potential penalties for this scheme, and this scheme alone, harsher than the potential rewards.

- **Telephone response in storms**. We have reservations about how the quality of telephone response in storm conditions can be effectively measured. We therefore support no financial incentives being associated with this mechanism, at least initially. In addition, we believe that the introduction of any such financial incentive in the future should be subject to a separate licence modification (i.e. not part of the distribution price review package).

- **Discretionary reward scheme**. We support the logic for this scheme.

- **Overall cap**. We strongly support the concept of an overall cap on exposure of DNOs to penalties. However, we regard the proposed 4% cap on downside exposure as unacceptably high. For a typical DNO, 4% of revenue could equate to around 1% on the cost of capital. We believe that this is an excessive degree of risk to expect DNOs to accept and may not be consistent with the duty to ensure that licensees can finance their functions. We believe that a figure of 2% would be more reasonable.

Standards of Performance

Semi-automatic payments

The proposal that DNOs should be more pro-active in making compensation payments will mean that DNOs will not only make more compensation payments but will also incur significant administration costs. No allowance has been made in the price control going forward for these additional costs, other than an allowance for storm costs, which is insufficient. We regard this as unacceptable. As a consequence, if Ofgem are determined to pursue semi-automatic payments (which we do not support), then the additional costs of this need to be fully reflected in cost allowances.

The proposal to impose a penalty equivalent to 'all customers affected by GS2 or the severe weather arrangements' writing in requesting compensation also increases DNOs' potential costs. As noted later in this response, the allowances to recover efficient costs are unacceptably low.

Severe weather standard

We support retention of the 18 hour standard for normal weather conditions.

Route for payments to customers

It seems sensible that DNOs should have the option to make payments directly to consumers.

Compensation for HV connected business consumers

We agree that the existing arrangements for compensation to HV business customers should remain the same.

Overall standards of performance

We support removal of the Overall Standards.

Interruptions incentive scheme

As noted above, we cannot agree to increasing financial exposure under this scheme to 3% until our concerns about the target setting and the detailed operation of the scheme have been resolved.

Form of the incentive scheme

We are generally supportive of a scheme with annual rewards and penalties, provided it is applied symmetrically and takes full account of exceptional events, including those relating to non-severe weather events. Indeed, we regard it as particularly vital that the IIP scheme for the next price control period properly provides for genuine exceptional events that are outside of the DNO’s direct control. Otherwise, the risks inherent in the IIP scheme will be excessive.

We also believe that the concept of a 50% weighting for planned CIs and CMLs provides perverse incentives. For example, DNOs may be encouraged to shift fault repairs into planned work, to reduce the impact of faults. Furthermore, planned CIs and CMLs have a direct relationship to work programmes, and this should be taken into consideration.

Setting targets

We would contrast the approach that has been taken to setting CML and CI targets with the approach to setting operating cost allowances. In the latter case, it is apparent that Ofgem’s model is statistically robust and hence suitable for the purposes of assessing relative efficiency. The same can not be said of the benchmarking which underpins the CML/CI target setting.

As Ofgem are aware, we support the work that has been carried out on disaggregation, and it is providing scientific and useful information based on a pragmatic approach. Overall, it is a useful tool in understanding gaps between the DNO's performance and how these might be closed, especially going forward when we have several more years' of data. However, we are very concerned at how the benchmarking process has been superimposed on disaggregation, drawing conclusions from incomplete analysis and understanding. It is also of paramount importance that we should discuss and explain the DNO specific issues that will transform the simple mechanistic approach to benchmarking and produce far more accurate benchmarks, and hence targets.

Some of the key issues for SSE which must be taken into account are set out below.

- **LV -** We support using current LV CI benchmarks based on each company’s current level of performance, as the cost to influence LV CIs nationally would be unreasonable. However, to use the national CML per CI level of performance to arrive at the CML benchmark concerns us greatly. The proposed process takes no account of SEPD's Consac issue, and until SEPD's Consac network is substantially overlaid, this will be impossible.

To illustrate the importance of the issue, 19% of SEPD's LV network is Consac cable yet it accounts for 51% of faults. We believe that our Consac network causes an additional 5 CI and 10 CML p.a., which must be taken into account in our benchmark and targets. The issue about 'response CML/CI' is compounded by the fact that our Consac networks generally have no interconnection.

Analysing the issue, the national benchmark CML/CI is 196, and SEPD's ratio is 200 i.e. at the benchmark. We estimate that SEPD's response on non-Consac faults is 140 CML/CI, and this is supported by our performance in SHEPD's area, which has identical management focus and processes, which is also 140 CML/CI and frontier. This infers that our average response on Consac faults is c. 300 CML/CI.

This poor performance for Consac faults does not reflect our frontier operational management focus. Furthermore, Consac often faults several times before the fault becomes permanent, enabling the location of the fault to be positively identified. This 'multiple fault before permanently faulting' behaviour incurs an estimated additional 4 - 5 CI. Obviously replacing all Consac cable is both uneconomic and unnecessary. Instead, as Consac cables develop faults we overlay not only the faulty section of cable but we will also extend the overlay as necessary if we assess that the surrounding cable is also likely to fault in a similar way.

There is clearly an additional cost in repairing Consac faults, for example all work on Consac cable involves excavation and subsequent reinstatement. This factor, in addition to the lack of interconnection results in restoration performance considerably worse that the benchmark. It is therefore not sufficient just to allow the extra cost of replacement, but it is also necessary to allow for extended response times. In our estimate the SEPD LV benchmark should be around 29 CML not 18.9 CML.

- **HV.** The disaggregation work at HV level has identified that SEPD has a problem with CI per fault in mixed and overhead network groups (i.e. the number of customers affected by each incident), whilst it demonstrates that SEPD is operationally a good performer (response / faults per km). As we have shared with Ofgem before, the observed negative CI per fault is due to the inherited topography, particularly the network layout variations within a group of circuits. For example, in many parts of the SEPD region where there has been high economic growth as urban catchment areas expand into rural areas, the numbers of customers connected further down circuits increases.

  This development means that reasonably dense communities are supplied by a predominantly rural network, with large numbers of customers connected mid-way or towards the ends of radial circuits. There can therefore be significant differences in the numbers of customers affected by an incident for circuits placed within the same group. The "gap" between actual performance and benchmark can only be addressed by significant investment to reduce customers per circuit (i.e. install more circuits), or sectionalisation and providing additional protection zones.

- **Tree cover.** Disaggregation shows that SEPD is a good performer on overhead fault rates. Yet SEPD is one of the most densely wooded regions (as Ofgem demonstrated in the October 2002 Storms Determinations), and tree cutting is creating an increasing negative public reaction. This implies that SEPD's overhead performance must be frontier (this will be partly due to the sound investment made in BLX, particularly in densely wooded areas). It is not sufficient simply to allow the extra costs of tree cutting, although this is important. Without adjusting/disaggregating for density of tree cover, we believe that SEPD's benchmark has been prejudiced. For example, had we reduced our tree cutting in past years, and allowed fault rates rise to the national average, we would have saved money and at the same time set an easier benchmark.

- **Inherited factors.** Some DNOs have inherited 'gold plated' networks e.g. fully fused HV overhead networks in one company and unit protected HV underground networks in another. These factors bias both upper quartile and average CI and CML and similar performance is unattainable without huge investment.

- **Remote networks.** We believe that the benchmarks and targets should reflect the challenges arising from the remoteness and lack of interconnection of the HV network in Scotland. It is unreasonable to expect the same performance levels for these networks, and the disaggregation process as is, does not recognise this issue.

- **Atypical data.** The entire disaggregation process has been based on three years of relatively benign weather, and the period also included the foot and mouth epidemic which reduced planned work. In addition, a significant storm such as that experienced in October 2002 will 'shake out' weakened trees and branches which would have fallen a some point in the future. However, the Exceptional Event process has removed the CIs and CMLs arising from this incident. Consequently, we genuinely do not believe these years represent the true underlying performance of our networks, and using the skewed data without applying some sense checking undoubtedly increases our risk and financial exposure.

The proposed 2020 targets include an improvement in performance of 0.5% pa, i.e. almost 10%, which is a very significant amount based on an assumption that ongoing generalised improvement is possible, unrelated to any additional expenditure that may or may not be available.

The proposed glide slope to achieve 40% of the 2020 CI target by 2010 is based on the presumption that there are some quick wins available in the first five years. It is our view that the toolbox of quick win solutions for the SSE networks (new technology and best practice) is almost exhausted, and long term significant investment is required, which may not be 'front end' loaded.

Without the increase in targets outlined above, SEPD would require an increase in the Quality of Supply capex allowed above that included in the Initial Proposals. We have written to Ofgem separately with comments on the PB Power reports and the capex allowances, but in summary it appears to us that Ofgem have ‘cherry picked’ programmes from our toolbox of Quality of Supply solutions and have not recognised the fact that some lower cost programmes (like automation) are finite and coming to an end and others are higher cost and subject to diminishing returns. We cannot therefore deliver the proposed target for the allowance given.

We propose two possible solutions:
1. Increase the Capex to a value that will deliver the published targets; **or**
2. Reduce the targets to reflect the existing capex.

We do not have a particular preference as to which solution is chosen but reiterate our previous point that our company case delivered a reasonable quality of supply improvement to our customers at an acceptable cost.

Rewarding current best practice

In paragraph 4.45, it is noted that: “Both WPDs have achieved very good levels of performance in terms of average restoration times i.e. compared with their benchmark”. As a consequence, they will each be given an additional reward of 1% of revenue to reflect this. We believe that Scottish-Hydro has done equally well, comparing average restoration performance to both the 2005 target and / or the benchmarks. Scottish-Hydro has achieved an average of 88.9 unplanned CML against a benchmark of 98.4 CML. We therefore request an equivalent £1m reward for Scottish-Hydro.

Furthermore, we feel it is unreasonable to identify CML performance alone. There should be some consistency with the treatment of CIs and telephony. We believe that an outstanding CI performance also deserves a special award. Hydro has achieved an average of 89.1 unplanned CI against a benchmark of 106.7 CI. We therefore believe that an additional reward for Scottish-Hydro's exceptional CI performances would be reasonable.

Finally, we believe that outstanding telephony performance should also merit an additional reward. Scottish-Hydro has consistently pioneered the frontier, being significantly ahead of the other DNOs for over two years. Again, we request a special reward for this outstanding performance.

Setting incentive rates

We would support the top-down approach, a graduated incentive, to a bottom-up calculation. We believe that this would be a more transparent approach.

Audits and adjusting data for inaccuracy

We believe these three paragraphs are inconsistent. Para 4.51 recommends retaining the streamlined audits, whereas the subsequent paragraphs will require a higher confidence level in the audit process, which will require more intensive audits.

We support the streamlined audit process, and believe that this could be taken further in future with DNOs conducting their own audits, with 'dipsticking' by external auditors.

We are very concerned that a DNO's data may be adjusted to take account of an inaccuracy identified in the audit - an audit process that carries only a 95% confidence level. Considering the financial exposure - say £230k per CML, this proposal represents an unacceptably high risk.

We also do not support the tightening of the overall accuracy requirements. This again would require an increase in the overall sample size to gain a higher level of confidence in the audit process. We regard the 95% lower accuracy threshold as being a backstop.

Frontier performance for this price control period

We support the proposal to allow the top four performers on CI and CML/CI to still be able to participate in the outperformance scheme.

Storm arrangements

We do not believe that Ofgem have made any case for tightening the storm compensation scheme and we are not aware of any evidence that the Interim Arrangements are not working. We are therefore firmly opposed to the doubling of DNOs' exposure under the scheme.

This point notwithstanding, we have a number of comments on the detail of the enduring arrangements for storm compensation, which are set out below.

- **Highlands and Islands**. In the interim arrangements for storm compensation it was recognised that the Highlands and Islands of Scotland were an exception due to the remoteness, the enormous geographic area and the exceptional severity of the snow and ice storms. Those areas are consequently excluded from the exceptional events compensation arrangements and we believe that this arrangement should be continued.

- **Gates for exceptionality**. We are very concerned that the proposed 'very large' severe weather event has a gate set at 50% of exposed customers. For SEPD, this would be an event with three times more impact than the October 2002 storm, and yet compensation would become payable after only 48 hours. It is important to consider that when an event of this magnitude occurs, national (and international) resources will play a major factor in restoration performance. Additionally, the complexity caused by the huge number of incidents has a 'square law' effect. This factor coupled with the inevitable reduction in the effectiveness of the restoration process after a number of days due to exhaustion, means that this threshold is unreasonably high.

  From our experience and historic performance (which was considered to be benchmark by the Energy Minister in 2002) we believe that a well prepared and well managed company dealing with a storm of 2002 proportions could reasonably invoke compensation payment after 48 hours. For SEPD 225,000 customers were affected i.e. 18% of exposed customers. On this basis, we would suggest that setting the gate at 20% of exposed customers would be more reasonable.

- **Annual allowance for exceptional events**. The allowance suggested would hardly cover the cost of fault repairs following a major event. In addition, at the same time Ofgem propose increasing DNOs' exposure under the storm arrangements to 2% of turnover. As noted above, we do not support such an increase in the scale of the scheme, but it is clear that the additional risks to DNOs could in part be mitigated by a more reasonable cost allowance. In addition, we believe that the annual cost allowance proposed in paragraph 4.61 for SEPD is based on incorrect data. We have reviewed the data extraction and have generated the following outputs.

SEPD Exceptional Event History

Year start	**Lightning event > 62.4 incidents**	**Any event between 63 and 101 incidents**	**Any event between 102 and156 incidents**	**Any event > 157 incidents**
2000				1
2001		1	1	
2002				1
2003		2		
Freq	0	0.75	0.25	0.5

We would ask that the table 8 in the 'Further details on storm arrangements' paper be amended for SEPD.

Finally, we believe the process and thresholds for major one-off events needs to be developed. We would be happy to work with Ofgem to achieve this.

Incentives for the speed and quality of telephone response

As noted above, we firmly believe that the rewards and penalties under this incentive scheme should be symmetrical. Indeed, we believe that the incentives to retain and retrain telephony staff to maintain our excellent service levels is significantly weakened by the proposal. We continue to put considerable effort into training our staff, as well as undertaking callbacks both during and post event. These are some of the reasons SSE is at and near the top of the league. Reducing the incentive to do well increases the risk that performance will slip providing poorer customer service. We believe that the existing scheme should be retained until 2010 with equivalent incentives.

We are also concerned that changing the format or content of the questions introduces a risk to companies. These issues need further development and consideration, and we would be happy to assist Ofgem in delivering that area of work.

Undergrounding in Areas of Outstanding Natural Beauty

We agree that wholesale undergrounding in areas of outstanding natural beauty can not be justified. However, there are some locations where it would be prudent to underground these lines, particularly where network resilience is an issue that can not be resolved by more severe tree felling, and diverting the line is not possible. We would be happy to put forward proposals for undergrounding for visual amenity reasons, should Ofgem decide that such expenditure would be included within the capex programme.

Environmental reporting

We suggest that the requirement to report on environmental issues is a duplication of other agencys' responsibilities. We would therefore urge Ofgem to keep any reporting requirements to an absolute minimum.

Discretionary reward

We support the proposal of a discretionary reward, although in our view, if this reward is to have the desired incentive properties it should be treated completely separately from the rest of the IIP scheme.

Chapter 5 – Distributed generation

As in previous responses, it is worth noting initially that we do not support the development of a complex scheme in order to incentivise DNOs to connect DG. We continue to believe that the scheme will lead to sub-optimal and delayed investment in DNO networks to accommodate DG due to the risks to cost recovery that DNOs will face under the proposed scheme. However, recognising Ofgem's commitment to the scheme, our remaining comments will focus on specific issues with the proposals as they currently stand.

There have been some useful amendments and clarifications to the scheme, but SSE remains concerned that some significant areas of risk remain. In particular, the mechanism for setting an allowance for operations and maintenance (O&M) costs does not adequately remunerate costs associated with a portfolio of higher than average cost schemes and the proposals for the network access incentive are in our view, not practicable.

We set out our detailed comments on these aspects below, followed by some comments on other parts of the proposals.

O&M costs

We are concerned about several aspects of Ofgem's proposal on O&M costs.

i) **£/kW basis where costs are higher than average**
O&M costs are incurred in relation to the actual assets that are used to allow the DNO's network to accept the output of DG installations and industry practice has tended to relate these costs to the value of the assets installed. Ofgem's proposal to provide an allowance for these costs on a £/kW/year basis introduces a systematic risk that those DNO areas with higher than average connection costs will not recover sufficient revenue to cover the relevant O&M costs.

ii) Ofgem's proposal for O&M cost recovery, set out in the March 2004 consultation, is based on the assumption that the average investment to cover both the sole use and shared assets used to connect DG is about £82/kW. This is "rounded up" to £100/kW and a 1% (of asset value) allowance made to produce the proposed figure of £1/kW for O&M.

iii) In SHEPD's area, which has been acknowledged to have higher than average costs for connecting DG, the "central case" figures from the DG-BPQ submissions show a total sole use and shared asset cost of about £120/kW. It is clearly inequitable for expected O&M costs in the SHEPD area to be remunerated on the basis of an average calculation of £/kW costs which demonstrably lie below the expected £/kW costs for this area. A comparable approach to that used for other DNOs would result in a figure of £1.3/kW.

iv) **Level of O&M allowance**
The second element in the £/kW calculation described above is Ofgem's assessment of the appropriate percentage of capital costs to use. Although we

recognise that Ofgem intends to review the O&M rate at each succeeding price control review, there has been no justification for taking the low end (at 1%) of the typical quoted range of DNO O&M costs of 1-2% of capital value. We expect that there will be additional operating costs, compared with current levels, as more DG connects and this view is supported by Ofgem's consultants. In our view, a figure of 2% would be appropriate.

v) **Risk on sole-use and "high cost" asset O&M costs**
Sole use assets and reinforcement costs in excess of the "high-cost" threshold will be borne by DG schemes in their connection charge. However, Ofgem propose that all O&M costs, including those associated with these particular assets will be carried by the DNO and funded by the £/kW O&M allowance. We cannot see any justification for including the O&M costs within the DG incentive scheme in these situations. To the extent that DG connections have relatively expensive sole-use asset costs or exceed the "high-cost" threshold, a DNO will be subject to the risk of the higher than average associated O&M costs. We expect a relatively high proportion of such schemes in the SHEPD area where long system extensions or reinforcements to remote areas are likely to be needed to accommodate many DG schemes.

vi) This risk could be mitigated, in the case of sole-use assets, by using a realistic overall £/kW figure for O&M that reflects the nature of the DNO territory and its expected costs, as discussed above. For "high cost" reinforcement that will be reflected in a DG scheme's connection charge, it would in our view, be equitable for the associated O&M costs to also be covered in the connection charge rather than funded by the DG incentive mechanism. These schemes are, by definition, judged to be outside the scope of the incentive mechanism. There is also a parallel in respect of any specific aspects of a connection that are requested above the minimum scheme determined by the DNO. O&M on any such additional assets would be expected to be covered in the connection charge as an additional allowance and we see no reason why O&M associated with "high cost" reinforcement should not be treated in the same way.

Network Access Incentive

We remain fundamentally opposed to the introduction of this element of the overall DG incentive scheme. As we have commented before, there is in our view no requirement on Ofgem to introduce such a scheme and we believe it drives an unnecessary distinction in treatment between demand and generation customers of the distribution networks. In relation to network interruptions, the interests of demand customers are protected by means of standards of performance and we see no reason why generation customers should be treated differently in this respect.

Ofgem has argued that the scheme is required in order to balance the premium rate upon which the DG incentive is based, and hence the rate reflected in the charges paid by DG connecting under these new arrangements. In response to this, we would comment that the premium rate (for the expected *average* scheme) is supposed to compensate DNOs for the real risks they face that the actual schemes that materialise could have higher than expected average costs. This risk/reward balance is undermined if Ofgem seek to impose mechanisms such as this to reduce the overall revenue from the DG schemes. Secondly, Ofgem has referred to the likely need to cap the use of system charges faced by generators. We welcome this approach and it demonstrates that generators will not necessarily bear the total DG incentive scheme costs.

We therefore urge Ofgem to consider, as an alternative to these proposals, making amendments to guaranteed standards arrangements such that DG schemes can qualify for payments under the supply interruption standards. This would have the merit of addressing Ofgem's concern while making use of existing DNO administrative arrangements.

If Ofgem nonetheless persist with the scheme that has been outlined in some detail within the Regulatory Instructions and Guidance (RIGs) document, then the time and cost involved in calculating unavailability payments on a DG by DG basis must be considered. For example, for a 50kW generator, network unavailability would have to extend to 20 days in a financial year (which is extremely unlikely) before the unavailability payment would amount to about £50. Even for a 1MW generator, a network unavailability payment of £50 would be generated by a total of 25 hours unavailability. Existing billing systems are not set up to use performance data to calculate bills and £50 is the sort of level of administrative cost we would envisage in any manual calculation of the rebate payment per DG scheme. We hope that these examples illustrate the disproportionate cost and effort involved in DG by DG scheme calculations. In our view, the cost of calculation would outweigh the payments made in the majority of cases. For the smaller DG schemes, payments are likely to be small and as such, these schemes would be better off under a standards compensation regime such as applies to demand customers.

We have the following suggestions to make the administrative costs more proportionate to the sums involved (for the avoidance of doubt, we would not support higher payments).

- By analogy with the arrangements for interruption standards payments for demand customers, we believe that eligible DG schemes should be required to claim a rebate payment within a month of the outage concerned. The DNO's role would then be reduced to verifying the claims actually made; and

- The licence conditions (and if necessary, the RIGs) should only refer to the amount of rebate paid out to eligible DG leaving the detail of each DNO's rebate scheme to be covered, after appropriate discussion with Ofgem, in the charging methodology statements. It would still be open for Ofgem to suggest the overall features of the scheme, but this could be done through consultation. Indeed it would be helpful for Ofgem to put views into the public domain on the expectation of how "baseline network interruption duration" would be calculated. DNOs should be allowed to propose ways of meeting the general objective of this arrangement without being bound by specific rules set out in RIGs or licence conditions. De minimis levels, banding of generator sizes and definition of baseline levels are all areas where DNOs might naturally have different approaches to the proposed overall methodology.

Other Points

These follow the same order as they are mentioned (if at all) in the DG Appendix.

i) **High Cost Projects.** We continue to believe that the high cost project threshold should be lower than £200/kW to guard against the risk that a greater than expected number of projects have costs between the "average" portfolio £/kW cost and the high cost threshold. Such an outcome, which is not unlikely due to the fact that DG schemes will no longer see the full reinforcement cost in their connection charge, would mean that portfolio returns would be lower than expected. It would be prudent, in our view, for Ofgem to reduce the high cost threshold to take account of this effect.

   In addition, we do not support the suggested additional criteria that "individual total project cost" should also be greater than £100,000 in order for a project to qualify as a "high cost project". This proposal adds unnecessary complexity to the already complex incentive mechanism and amounts to a proposed subsidy for smaller generating schemes.

ii) **Ancillary Service Costs.** We agree that ancillary services from generation, which assist in network operation, are likely to become more significant as the penetration of DG increases. We note that no allowances have been made for these but do not consider, as Ofgem suggests, that such costs will necessarily yield savings in opex or capex. As noted in our discussion of O&M costs, we expect that there will be additional operating costs, compared with current levels, as more DG connects and this view is supported by Ofgem's consultants. As distribution system operation becomes more complex, operating costs will rise and services from DG may help to mitigate the increase but they are not likely to reduce costs from current levels.

iii) **Updated Connection Boundary.** Ofgem discusses two options to cater for the fact that the DG incentive parameters have been set on the assumption that only sole-use assets were to be covered in the DG connection charge. Ofgem rightly note that the "shallowish" boundary definition developed through the structure of charges workstream and the "high cost project" mechanism both mean that some element of reinforcement costs will, in fact, be remunerated through the connection charges. We support Ofgem's preference to cater for these developments by adjusting the price control formulae such that the DG's contribution to reinforcement costs through the connection charge is netted off the capital sum entering the pass-through arrangements under the incentive scheme. The alternative of recalculating the parameters of the scheme, based on further information requests, is not one that DNOs would welcome at this stage of the review process.

iv) **Profile of Pass Through Revenue.** We continue to support a "DG-RAV" approach to profiling the pass-through element of the incentive scheme, although Ofgem has favoured an annuity approach. Apart from the advantages of the RAV approach that we have outlined previously, it appears that there may be some difficulty in specifying, with the annuity approach, the calculation whereby the undepreciated element of DG investment is transferred to the main RAV in the event that assets become stranded.

v) **Treatment of Tax.** We welcome Ofgem's commitment to align the DG incentive parameters with the cost of capital assumptions that are finalised for the main price review. On the matter of tax treatment, we have advocated that the DG incentive parameters continue to be based on a pre-tax cost of capital, which is derived from the post-tax figure by adding the average marginal tax rate across companies.

vi) **Stranded Assets.** We believe that there are still risks for the DNO with the current proposals, that the MW expected from a particular DG scheme do not materialise or disappear within the depreciation life of the assets. It is inequitable, in our view, for DNO investment to be at risk of returns less than the cost of capital due to risks affecting their DG counterparties. The commercial environment in which DG developers operate requires rates of return considerably in excess of those of regulated utilities to cover their risk profile.

Ofgem's proposal, set out in the RIGs, is for a "connection start date" to be agreed between the DNO and the DG scheme. This would define the point at which: the DNO system is ready to accept the DG output; the DG scheme starts paying use of system charges; and the DG MW are eligible for the £/kW element of the DG incentive scheme. We acknowledge that this definition largely protects the DNO from delays affecting the DG scheme's readiness to generate at the agreed connection start date.

However, it does not protect the DNO from situations where the DG scheme fails to materialise (due, for example, to insolvency) once a connection start date has been agreed. In our view, if it is not possible to accommodate this concern within the parameters of the DG incentive scheme, then it will be necessary for the DNO to require security from DG developers for an appropriate proportion of the cost of any reinforcement works. This security would be held until the schemes produce their full expected output. Similarly, termination payments will have to be considered to cover the situation where a DG scheme fails part way through the assumed depreciation life.

vii) **Price Control Reopeners**. There is no mention in any of the DG-related papers issued in June, of provisions to allow a DNO to appeal to Ofgem for a re-opening of the price control due to issues associated with the DG incentive scheme. In our view, due to the uncertainties associated with DG and the operation of the incentive scheme itself, there is a strong case for both a general re-opener and one linked to shifts in government policy on renewables, such as a major reform or revocation of the ROC scheme. In the latter case, we believe that 100% RAV funding should be provided for any outstanding investment. In both this and the general case, the DNO should have rights of appeal to the Competition Commission in the event that Ofgem refused the DNO's application for the re-opener.

Innovation Funding Incentive (IFI)

We welcome the continuing clarity on the way that this scheme is intended to work but are disappointed that there has been no improvement on the profile of the pass-through rate, which continues to average 80% over the next price control period.

We also welcome the continuing dialogue with Ofgem aimed at maintaining the momentum of potential IFI developments by allowing some projects to be initiated from October 2004. I can confirm that SSE's DNO companies do intend to initiate IFI projects before 1 April 2005. We would welcome clarity on the exact reporting requirements and price control treatment of such projects.

A remaining issue for the IFI scheme in our view, is the requirement for DNOs to be certain that, once funds are committed to IFI projects, the appropriate pass-through element will indeed be added to allowable revenue. The RIGs document outlines a two-stage information process for IFI schemes, whereby budget information is presented before the start of the relevant financial year and outturn financial information is provided after the end of the financial year. It will be important, for the purpose of reducing regulatory uncertainty in this area, that Ofgem commits to a process of formally accepting the projects put forward by DNOs for pass-through of all expenditure at the appropriate rate. In our view, this process should be set out in the licence conditions.

Finally, we welcome the additional flexibility proposed on the proportion of internal costs that can be included in eligible IFI expenditure. We expect that any network projects up to *and including* 132kV networks would be included in the IFI scheme, although paragraph 2.2 suggests only "up to 132kV".

Registered Power Zones (RPZs)

As with the IFI schemes, we welcome the continuing clarity on the way that this scheme is intended to work, particularly in the proposed application and registration process. There are still some elements of this process to be confirmed, such as the eligibility criteria and the proposed application form. These could be contained within the RIGs document.

We recognise that Ofgem has increased the incentive rate for RPZ schemes to three times the rate used in the main DG incentive scheme. We assume that this multiplication factor will apply to the actual DG incentive rate used in each DNO area and specifically that the base rate used in SHEPD's area will be £2/kW as in the main DG incentive proposals for this area. Ofgem have improved prospective rates of return compared with previous proposals but we would still welcome a longer timeframe than five years for the application of this premium rate. As noted before, the greater the prospective revenue stream associated with RPZs, the greater will be the incentive for DNOs to seek out marginal opportunities for connecting additional MW.

We note that Ofgem has proposed a limit of two RPZ applications per year for each DNO for the first two years of the scheme's operation. We understand the rationale for limiting such schemes initially to allow all parties to gain experience of the scheme and the issues arising. However, we are still concerned about the relatively low level of the proposed funding cap per DNO per year (at £0.5m). The initial limitation on applications proposed by Ofgem adds weight to our previous arguments that there should be a "carry forward" mechanism of unused "headroom" under the proposed cap. Given that projects are likely to build up gradually over the price control period, we suggest that a "carry forward" mechanism is not limited to the immediately following year as in the IFI scheme, but becomes, effectively, a rolling "correction factor" for any under-recovery in the earlier years of the price control.

RIGS

We have set out detailed comments on the RIGS in appendix 1 to this paper.

Chapter 6 - Cost Assessment

Operating costs: normalisation

We agree with Ofgem that robust benchmarking requires good quality comparable data. We therefore understand in principle the desire to normalise costs between DNOs to arrive at an underlying ongoing efficient cost. However, the level of costs arrived at through the normalisation process does not represent a "real" DNO. Indeed, even the frontier company's costs are below its actual costs in 2002/03. This is not necessarily an issue in terms of comparing relative efficiency. It is however, absolutely vital that the costs that have been adjusted to ensure comparability (e.g. storm costs) are added back to each DNO at the end of the process to arrive at the allowed costs going forward and that the amounts allowed fully reflect those costs.

In terms of the specific adjustments made, we firmly believe that despite the move to CSV3 and the £1.6m allowance, the regional costs for SHEPD have been significantly understated. We have written to Ofgem separately on this specific issue and would welcome a response to that letter.

We also continue to believe that inter and intra-company margins should not be disallowed, certainly not for contestable activities such as telecoms and transport. Where these services are being provided efficiently, the margin should be allowed. However, clearly Ofgem should remove any excessive margins over market rates for the purposes of the normalisation work, but not the whole margin.

Top Down Benchmarking

Composite Scale Variable

We believe that the choice of CSV3 remains appropriate and is a closer proxy for the cost drivers than the alternatives considered. The assets are the prime driver of costs for a DNO, therefore it follows that the prime driver in the variable should be a proxy for the number of assets.

We also note that repeating the regression using alternative formulations produces odd results. In particular, applying the CSV used at the last review to the normalised data results in a broadly similar statistical fit, but DNOs under the same management groups show a very different position relative to the frontier. We do not believe that this is a credible conclusion. We also do not believe that this is consistent with the findings of the Ernst and Young report. As a consequence, we believe that Ofgem should continue to apply CSV3 to the normalised data for the purposes of assessing relative efficiency.

Basic regression

We continue to support an approach based on the use of 'controllable costs' plus total fault costs. We also believe that, given all DNOs are essentially the same businesses carrying out the same activities, the regression is reasonable statistically. It will always be possible for the statistical "purist" to argue that the lack of observations undermines the robustness, but in our view that is more than countered by the underlying comparability of the companies and the knowledge and understanding of the costs.

The fact that there has been convergence since DPCR3 also supports the basic regression, as does the "qualitative" report by Ofgem's efficiency consultants Ernst & Young.

Alternative regression analyses

As noted above, we are of the view that the basic regression is robust. In addition, the use of the upper quartile allows for any doubts as to the validity of the frontier. We therefore agree with Ofgem's conclusions that there should be no specific adjustment for merger savings, there is no adjustment necessary for quality of supply and that total cost measures are not a good indication of operating efficiency. We also agree that the main regression should form the basis for setting operating cost allowances.

Glidepath

We support catch-up by 2005 for the reasons set out in the paper. In particular, we agree that extending the glidepath would create perverse incentives by rewarding the high cost companies.

Total opex allowance

Although we welcome the (partial) recognition for setting the frontier that the use of the upper quartile implies, this benefit is removed by assuming an ongoing efficiency assumption from 2005/06 of 2% p.a. We do not believe that there is any justification for this assumption. Indeed, while we included in our FBPQ an ongoing efficiency target of 2% p.a., this is an internal target set against a background of costs rising year on year.

However, Ofgem have not allowed the increases in day to day running costs which in practice are met by the efficiency target (i.e. we also forecast that several costs were due to rise). Ofgem have ignored these cost increases, but have "cherry-picked" the 2% efficiency assumption from our BPQ.

We have set out these disallowed costs in the attached appendix. In our view, it is not reasonable both to disallow these costs and to make the ongoing efficiency assumption. In effect, we have been set a 4% p.a. efficiency factor, not 2%. This undermines incentives to be at the frontier in future. It is also clear that this is a very challenging target for the company at the efficiency frontier to achieve. Indeed, we note that Ofgem's efficiency consultants Ernst & Young state in their report on SSE: "We do not believe that there are further substantial operational efficiencies to be achieved over the five years of DPCR4"

As a consequence, we believe that Ofgem should either recognise, in full, the cost pressures as indicated in our FBPQ or remove the 2% efficiency assumption. The detailed cost increases are set out in appendix 2 to this paper.

We also note that Ofgem claim that the work commissioned on Total Factor Productivity from Frontier Economics supported an ongoing efficiency assumption in excess of 2% p.a. We do not accept this interpretation. It is equally possible to interpret the Frontier Economics work as indicating that there are no further productivity savings to be made. In addition, it is clear that the TFP assumptions apply, by definition, to the industry average and not to the upper quartile or frontier. We do not therefore believe that the TFP work provides any justification for setting a 2% ongoing efficiency assumption to the upper quartile companies.

Historical capex and RAV roll forward

SSE note that work is still ongoing on final calculation of the RAV at 31 March 2005. However, we would urge Ofgem to provide final clarity on this important issue as soon as possible in the process.

We support the adjustment made to include meter recertification into the RAV from 1st April 2000. However we still have a number of areas of concern on adjustments made to the RAV in the June paper and potential adjustments that may still be made. These are as follows:

Fault Capitalisation – Since publication of the June proposal paper Ofgem have issued a clearer definition of fault costs that should be capitalised and included in the RAV. We welcome this clarification and have resubmitted figures to Ofgem based on this revised definition. In the HBPQ and our regulatory accounts we had excluded from the RAV all capitalised fault expenditure that had been incurred on line and cable repairs. We were disappointed to note that this had not been done by all DNOs. We would expect Ofgem to consistently apply this revised fault capitalisation definition to all DNOs without exception. Alternatively, the same rules as adopted by these companies should be applied to SSE, which would imply an increase in the RAV

Intergroup Margins – As we have said above, we disagree with the exclusion from the RAV of all inter group margins on services provided from within our Group that could be obtained from third party service providers. We would ask that Ofgem include the margins excluded from our RAV in Table 6.6 of the June proposals within the revised calculation of RAV planned for the September paper.

Overhead adjustment – We await discussions on any adjustment that Ofgem propose to make to the RAV figure for overhead capitalisation. We recognise that this is a difficult area to assess given the different structures and accounting policies adopted by different DNO’s over the last few years and the availability of detailed accounting information for earlier years. It is our opinion that any adjustments that Ofgem propose should be clear and fully understood by DNOs.

Other Capitalisation adjustment – A reduction of £8M for Southern and £5M for Hydro has been made in Table 6.6 of the June paper. We believe that this refers to meter recertification costs prior to 1st April 2000 and “other capitalisation” adjustments going back to 1st April 1998. We do not understand the basis of the “other capitalisation” adjustment and we have asked for clarification on this. If this refers to adjustments in order to apply accounting policies suggested by Ofgem in the

Regulatory Accounting Guidelines (RAG's) then we believe these adjustments should only be made to accounting periods after 1st April 2000 when these policies were first outlined. If Ofgem believe that these accounting policies should apply retrospectively to 1st April 1998 then we strongly believe that the adjustment to include meter recertification costs in the RAV should also be applied retrospectively to that date. To do otherwise on areas where regulatory accounting policies have changed would be inconsistent.

Review of future capex

Forecast review adjustments

We have had the opportunity to review the PB Power draft report underpinning the Initial Proposals. We broadly support the conclusions of the PB Power Report. For the most part it uses reasoned and robust arguments and analysis to reach its conclusions. However, we still remain disappointed our Company case was not adopted as the accepted requirement as we still believe it provides a more balanced package for customers. We have submitted more detailed comments to PB Power. We look forward to meeting with PB Power and Ofgem to discuss the report.

Setting capex allowances and investment incentives

We broadly support the introduction of the sliding scale mechanism. We believe that the mechanism is complex, but we welcome the maintaining of current incentives to invest efficiently for those companies that submit realistic forecasts. The mechanism also recognises that overspends may be necessary, provides an additional reward for those that spend up to their allowance and puts in place a framework to enable a DNO to make an informed decision on levels of investment.

Mechanics of the sliding scale approach

We have yet to see the detailed mechanics of the sliding scale mechanism, but presume that once allocated to an incentive rate band, then underspends/overspends are treated in the same way as the current capex roller.

Chapter 7 - Financial Issues

Cost of capital

We are disappointed that Ofgem have not moved any further forward on the Cost of Capital in the Initial Proposals. We have written to Ofgem in detail with our views since the March document, as have others, and the ENA has also submitted on 23rd July further market-based evidence in support of a cost of capital above the top end of Ofgem's proposed range. We would have expected at least to have seen the range narrowed by applying a collar to the range, as Ofwat have done in the water periodic review. In any event, we would urge Ofgem to clearly set out their proposals for the cost of capital in the September update document.

The relevant number to focus on is the traditional post-tax cost of capital. The so-called "Vanilla" cost of capital is confusing and is in any event simply a modelling device. Similarly, the pre-tax cost of capital is also not directly relevant because of the changes to the tax rules. Our shareholders and the analyst community will therefore focus on the traditional post-tax cost of capital. Indeed, we believe that the Vanilla concept significantly complicates the process and could usefully be abandoned in the interests of transparency and consistency.

As noted above, we have written separately to Ofgem about the cost of capital and there seems little merit in repeating those points in detail here. However, in short:

- With the significant capital requirements and potential negative cash flows for some DNOs, it is essential that the cost of capital is set at a level sufficient to attract equity investment;

- We consider that this requires a return on equity in excess of 10%, if DNOs are to be able to compete in the international capital markets. This figure is also supported by assessing the dividend growth model;

- We therefore believe that efficient companies should be capable of earning more than 6% post-tax real. Assuming that there is scope for such companies to outperform the price control by 50-100 bps, then a minimum cost of capital of at least 5.25-5.5% is inferred;

- It is clear that academic evidence can justify a wide range of possible answers for the cost of capital. For example:

Ofgem CAPM	4.2-5.0%
NERA	5.5%
OXERA	3.8-5.5%

- A post-tax WACC in the range of 5.25-5.5% can therefore be justified by the academic evidence, as well as an assessment of the requirements of equity investors.

Finally, we note that Ofwat has recently published initial proposals for the periodic review of the water companies. We are still assessing the detail of that paper, but Ofwat have seemingly adopted a post-tax WACC of 5.1% rising to 5.5% by 2010 (reflecting financing issues). We do not consider any logical reason for a lower cost of capital to be applied to the water industry than in electricity and indeed we would regard electricity as more, not less risky.

We recognise that Ofgem is an independent regulator and is not bound in any way by decisions Ofwat have made in the water sector. Nevertheless, the fact remains that under current proposals water companies will be operating at a base cost of capital of 5.5% by 2010 compared to 4.6% in electricity distribution. This spread would distort equity markets and is in our view not justified by the evidence.

Tax

We are still unable to replicate Ofgem's tax calculation. We therefore welcome the DNO tax managers meeting with Ofgem to try to bottom-out the differences. We believe this is mainly due to errors in Ofgem's calculation, but there are some uncertainties. It is nevertheless apparent that this is a serious concern and we believe that Ofgem have significantly underestimated SSE's tax bill.

Possible areas of difference are:

- Capitalised faults and non-operational capex are assumed to be opex. In practice, this is not how these items are treated for tax purposes;

- With regard to the opening tax pools and how capital additions are allocated to the tax pools, we are not convinced that Ofgem have actually used our tax computations, as claimed, as the basis for these numbers. We also have reservations as to the opening balances used and the capital expenditure split between short and long term life. In particular, we believe that metering expenditure may have been included both in the pool value brought forward and capital expenditure, which will significantly understate the tax allowance;

- Ofgem have calculated interest by applying a nominal interest rate to a nominal RAV. This is not consistent with how the debt element of the return is calculated and our debt balance is not inflated each year. As above, this would tend to understate the tax due;

- Ofgem have not included any adjustments for disallowable opex and capex in revenue. These are necessary adjustments required to calculate a tax charge, and if excluded this would understate the tax liability;

- Ofgem appear to have imputed a debt level based on 60% gearing. The actual debt used for the tax allowance should be based on our actual forecast of debt; and

- Ofgem have (deliberately we understand) not allowed any tax in respect of rewards under the various incentive schemes (including the sliding scale and rolling capex mechanisms). We regard it as unacceptable that these incentive payments have not been grossed up for tax purposes. The practical effect of this approach is to significantly weaken the incentive properties of Ofgem's incentive mechanisms and this was never made clear when these issues were consulted upon.

It is therefore clear that much work remains to re-calculate the tax allowances for all of the DNOs. We are concerned that there is not much time to deliver that work in this highly technical area before final proposals are brought forward by Ofgem. Moreover, it is also apparent that some uncertainties exist about the exact nature of tax allowances going forward and this makes it difficult to finalise ex-ante allowances for each DNO.

It may therefore be necessary to consider a form of pass-through of tax costs, at least for the next price control period until there is greater certainty about how the new tax regime will work in practice. Clearly in considering any such arrangement incentives to ensure continued tax efficiency will be paramount. However, we believe that this could be achieved by setting a separate tax efficiency incentive scheme.

At its simplest, this could involve clearly flagging up now that any inefficiently incurred tax costs between 2005-2010 risk being disallowed at the next price review, possibly coupled with the prospect of additional rewards at the next price review for those that can demonstrate tax cost efficiency. This would be sufficient to ensure that any pass-through of tax costs would not undermine tax efficiency on the part of the DNOs.

An alternative approach might involve the mechanism for dealing with uncertainty put forward by the DNOs. That scheme involves formally recognising the explicit allowances for certain categories of cost and provides for a narrow re-opening of the control where actual costs deviate from those ex-ante allowances. It may be possible to include tax as one such category of costs, which would provide some protection to DNOs in the event of a significant variation in tax costs from the Ofgem allowances.

In any event, given the scale of the difference between the DNOs and Ofgem on tax allowances, it is of vital importance that Ofgem focus their efforts on resolving these issues before the September update.

Regulatory asset value and depreciation

We support moving to the same 20-year depreciation profiles for all DNOs where the Vesting assets have become fully depreciated. Accelerating depreciation in this way avoids the 'cliff-face' fall in cash flows as vesting depreciation runs out. It also avoids some of the financing problems which some DNOs are experiencing. However, consideration needs to be given, in our view, to the value of some DNOs, for example those that have a low RAV and low capex, in the future. We believe that accelerated depreciation is a short-term solution and does not avoid the real need for a sufficient cost of capital.

Pensions

We welcome the significant progress to date on pensions issues. The main outstanding area is the treatment of ERDC costs. We still view disallowing ERDC costs as unacceptable and intellectually incorrect. In particular, Ofgem must recognise that customers have benefited from staff cost reductions, and that the up-front investment costs to achieve those savings have been efficiently incurred. It is therefore reasonable for customers to pay a proportion of the investment costs necessary to achieve those efficiencies.

However, we welcome the reference in the paper to a possible compromise on this issue based on only disallowing 30% or so of those costs on the basis of the NPV share of efficiency savings. We would urge Ofgem to confirm that approach as a way forward in the September update document.

Financial indicators

The DNOs have already submitted a paper to Ofgem about the appropriate financial ratios going forward, which we would urge Ofgem to consider. To the extent that the work on financial ratios indicates that some or all DNOs will have difficulty financing their respective investment programmes, we believe that this should be addressed by an upward adjustment to the industry-wide cost of capital, as Ofwat appear to have done for the water companies.

Appendix 1

Comments on Version 1 of DG Regulatory Instructions and Guidance (RIGs)

Our comments on the above document, published at the same time as the June proposals document, are set out below.

Definitions

A general comment about the main DG incentive and the IFI and RPZ schemes is that definitions affecting the allowable revenue from these schemes should be part of the price control licence condition rather than the RIGs. We understand that Ofgem has accepted this point in discussions subsequent to the publication of the proposals.

Chapter 1

Paragraph 1.3 sets out Ofgem's intention to make changes to the RIGs as infrequently as possible. We support this intention but would also note that care needs to be taken, in framing the initial RIGs, not to place too great a regulatory burden on DNOs in the first place. We are concerned that the information requirements associated with two areas in the RIGs – namely network interruptions and O&M costs – could be significant and out of proportion with the value of that information to Ofgem. We comment on these aspects more fully below.

Chapter 2: Main DG scheme

Definitions

We note that there are no definitions relating to "high cost projects" and the way that costs relating to these will be treated. Similarly, although the term "assets transferred from DG capex to demand capex" is defined, it is not sufficiently clear how such a transfer will work. The mechanism around both of these points needs to be set out in detail in the price control licence condition.

Network unavailability

Our strong concerns in this area are set out at length in the part of our response to the main price control document that deals with DG issues.

Operation and Maintenance (O&M) costs for DG

We have already commented that it will only be possible to estimate these costs, as systems to record such costs throughout the year do not exist and are not, in fact, practicable. This point was raised by other DNOs at the recent meeting to discuss the RIGs document. We share the concern expressed at that meeting that placing an obligation to provide this information in the RIGs could imply that it effectively becomes a licence obligation on DNOs to have recording processes in place to measure this quantity. We therefore propose that Ofgem either makes it clear within the RIGs that it is only an estimate that is required, or asks for the estimate as a separate information request outside the RIGs.

Definition of DG capacity

2.6 Following the meeting to discuss the RIGs, we understand that different definitions of DG capacity have been considered: for example, the authorised capacity agreed with the generator or the name-plate rating of the generator. In our view, the name-plate rating is the best measure of DG capacity since network issues with DG are mostly driven by fault levels, which are driven in turn by DG name-plate ratings. The definition should make it clear which measure should be used for the purposes of the scheme.

Definition of connection start date

2.5 In its current form, the definition could be undermined by events outside the control of the DNO. For example, if wayleaves required for necessary system reinforcement are delayed, then a connecting DG scheme might have the capability to achieve some, but not its full level of output capacity. In such a situation, it would still be appropriate for the full level of output to count towards the DG incentive mechanism and for the DG scheme to pay appropriate use of system charges. This issue could probably be addressed within the definition by referring to levels of output "agreed" between the DNO and the DG scheme.

Other Points

2.3 There is a reference to chapter 5 in the third bullet point, but the material in chapter 5 does not actually appear to clarify the comment being made.

2.4 In our view, the wording of the first sentence here could be clarified as it could currently be interpreted to mean that the upgrading or expansion could exist before 1 April 2005.

2.5 The "registered" in this sentence should be "regulatory", in our view.

Chapter 3: IFI

Turnover

We suggest that it is clarified in these RIGs whether the turnover figures required at 3.2 and 3.8 is turnover for the regulated business or total turnover for the licensed entity.

Eligible IFI project

We suggest that the qualification in brackets in the first sentence of this definition should read "(up to *and including* 132kV)" to make if clear that 132kV projects can be included within the scheme.

Eligible expenditure

It is important that DNOs have certainty that once funds are committed to IFI projects, the relevant costs will be allowable as defined under the scheme. It will therefore be important for the process set out under the licence to clarify that once Ofgem has "confirmed the acceptability" of the projects and budget information provided by a DNO in March each year, that the expenditure under those projects will unequivocally be counted as eligible IFI expenditure.

Chapter 4: RPZ

General

We suggest that the application forms and associated guidance for RPZs should be included in the next version of the RIGs.

RPZ starting year

It is not clear what the definition at 4.4 is referring to with the addition of the phrase in square brackets. Once an RPZ has been registered and perhaps given a reference name, we do not see the value of continuing to report the starting year in each successive reporting period.

Chapter 6 – Reporting Arrangements for DG Incentive

In paragraph 6.3, the date of 31 June (should this be 30 June?) is given as the date by which the required information under the RIGs is to be provided by DNOs. This lines up with the licence requirements for other information relating to price controls. However, in recent years, the deadline for price control and other financial information has been put back to 31 July. We would request that, where an extension is given on the latter information, that the DG-related information is also given an extension in order to keep year-end processes in step. On a minor point, there is a spelling mistake "capes" in the fourth bullet point in this paragraph.

Chapter 7 – Reporting Arrangements for IFI

We would comment that the term "project schedule" listed at paragraph 3 as part of the information required before 1 March each reporting year has not been defined. In addition, there will not be very many days between the time that Ofgem states that it intends to publish RIGs ("normally in February") and the date by which it requires the beginning of year information for the IFI scheme ("on or before 1 March"). To address this, we suggest that the part of the RIGs relating to the beginning of year information is published by at least the end of the previous December.