

Cemil Altin
Head of Price Control Reviews
Ofgem
9 Millbank
London



9 August 2004

Dear Cemil,

Electricity Distribution Price Control Review: Initial proposals - June 2004

We welcome the opportunity to comment on Ofgem's initial DPCR proposals. This response by EDF Energy is on behalf of the three distribution licensees, EDF Energy Networks (EPN), (LPN) and (SPN).

EDF Energy remains committed to working with Ofgem to achieve an agreed outcome to the Distribution Price Control Review (DPCR4). We have a shared responsibility to customers to achieve this.

As you are already aware, EDF Energy has some serious concerns about Ofgem's Initial Proposals. We do not believe that the Initial Proposals are in consumers' interests and we consider that they do not provide enough money for us to meet our obligations. Some of the key areas for concern have already been the subject of various meetings and letters between our respective organisations. Our response to the Initial Proposals addresses these key areas and refers, where relevant, to earlier EDF Energy correspondence to Ofgem. We also present additional evidence and analysis in support of our response where this is required.

The key points in our response, under four main sub-headings, are as follows:

Timetable and consultation process

- We do not believe that Ofgem's process for DPCR4 has been sufficiently robust for it to be able to demonstrate the fulfilment of its relevant statutory duties in a number of key respects.
- We consider that important elements of our submission (and other evidence) have not yet been given the due level of consideration by Ofgem, necessary for it to demonstrate that it has met its statutory obligations. These include:
 - Base Case submission on capital expenditure and the deficiencies of PB Power's capex report;
 - Detailed evidence of regional cost factors;
 - Evidence of significant accounting differences between DNOs and the lack of accounting definitions going forward;

- Many deficiencies of Ofgem opex benchmarking (use of a crude regression model, lack of robust/understood cost drivers, poor recognition of long term capital substitution, limited recognition of error and the associated unsubstantiated assertion of inefficiency); and
- DNO Case capex submissions generally.
- We are concerned, given that many crucial elements of the price control were not defined in the Initial Proposals, that resolution of important issues is being pushed to the back end of the process. This increases the likelihood of DNOs not being given sufficient time to carefully consider the full proposals.

Operational expenditure

- We consider that Ofgem’s operating cost (opex) benchmarking conclusions are not reliable and must be reviewed. It seems certain to us that the opex numbers used in the regressions are not based on standard definitions. It would not be acceptable to EDF Energy that such differences could give any DNO an unfair advantage or disadvantage (which would clearly not be in consumers’ interests). It is essential that standard definitions, to be used from 1st April 2005, are agreed as the basis of the final proposals at the end of 2004. It is unacceptable that DNOs should suffer the consequences of the absence of such definitions. Indeed, we consider that such a policy would be inconsistent with Ofgem’s duty to “secure that licence holders are able to finance [their] activities”¹.
- Ofgem is implicitly assuming that its fixed weighting composite scale variable (CSV) fully explains the impact of differences in “normalised” opex costs and acts as a complete proxy for the underlying “real” cost drivers DNOs face. Asserting that differences are wholly due to inefficiency is not credible. We are unaware of Ofgem carrying out any robust analysis of cost drivers – which obviously impacts the accuracy of Ofgem’s benchmarking model. Of equal concern to us is the use of fixed weightings, despite the fact that underlying cost drivers are bound to vary between DNOs. A fixed weighting between the CSV components would create a windfall for some and a penalty for others, which cannot be in customers’ interests. Modelling approaches that allow the mix of variables to be optimised will give a fairer result that is more consistent with Ofgem’s financing duties. We welcomed the opportunity to discuss these views at the 5th August CSV workshop. We will be writing separately with our thoughts on the outcome of this workshop and the evidence that was presented.
- Inadequate regional cost allowances have been made in the Initial Proposals. Ofgem’s failure to properly take account of regional costs for Greater London (for all three of our DNOs) contributes significantly to the erroneous perception that EDF Energy’s DNOs are relatively

¹ S3A Electricity Act as amended by the Utilities Act 2000.

inefficient. It is inappropriate for Ofgem to replicate the restricted adjustment (for LPN only) made in the previous price control review in the face of the Oxera study formally submitted by us on regional costs factors.

- The efficiency glide-path proposed by Ofgem is extreme and does not provide sufficient time to adjust costs; nor is any account taken of the costs of achieving such savings. Ofgem is proposing to disallow costs at a faster rate than the long-term rate of efficiency growth. This is without justification and is not supported by the evidence available to Ofgem. In addition, Ofgem's decision to disallow costs from 2005 is unprecedented and inconsistent with good regulation and, we believe, Ofgem's statutory obligations.
- The proposed best practice award in quality of supply is not consistent with incentive regulation. It is also unfair since, if such retrospective awards are to be granted, there is an equally strong case for rewarding the excellent achievements of LPN – which is a frontier performer in respect of not interrupting customers in the first place.

Capital expenditure

- Ofgem's approach to assessing capital expenditure (capex) forecasts has serious limitations. Our Base Case capex submissions include measures specifically directed towards maintaining "appropriate", rather than "constant", levels of risk. We do not believe that PB Power's modelling reflects this important objective. Similarly, we consider PB Power's view of the amount of capex required to be inconsistent with our general duty to develop and maintain efficient, co-ordinated and economical systems of electricity distribution. In addition, we are disappointed that PB Power seems prepared to ignore their own model results for load-related capex – with arbitrary and unsubstantiated cuts to both LPN and SPN model outputs.
- We are confident that, if the process is sound, we can close the capex gap between us and find an acceptable solution. As we have informed you previously², we have asked BPI to provide independent verification of our load related capex plans, which we are sharing with Ofgem. We are prepared to fully accept BPI's findings, which are based on a thorough analysis of each major reinforcement project rather than a top-down modelling approach.
- We acknowledge Ofgem's helpful decision to remove oil-filled cable replacement expenditure from the initial NLRE analysis pending further consultation. We intend to continue to work closely with Ofgem to develop a regulatory and financial framework that will allow us (and other DNOs) to undertake this work at a rate that is commensurate with the environmental and operational risk that these assets present.

² Presentation to GEMA 15th July 2004. Letter to Martin Crouch 30th July 2004.

- A robust review process for capex plans would remove the need for a sliding scale mechanism and therefore you should assume that we are not supportive of such a mechanism being a substitute for arriving at appropriate, verifiable and specific capex plans. From the above, it is clear that we do not regard PB Power's views as a robust basis for Ofgem's proposed sliding scale mechanism.
- There is an inconsistency between quality of supply targets for 2010 and the proposed incremental capex allowances for SPN and EPN. Significant capex for quality of supply has been disallowed without apparent reason and there does not seem to be an equality of treatment between DNOs.

Financial aspects

- We consider the assumed cost-of-capital to be too low, and inconsistent with what is being proposed for the water sector (which we do not accept is the higher risk activity). We have submitted evidence from OXERA and NERA and believe that it is essential for Ofgem to include an update (and upward movement) to its thinking in the September document, rather than wait until the final proposals in November.
- Under Ofgem's Initial Proposals, SPN has a "major financing issue" and so a solution must be found to this. We believe that, to be consistent with its financing duty, Ofgem's approach to this issue should be non-discriminatory and consistent over time. Ofgem's current stance seems to pass neither of these tests.
- Pensions funding must be adequate. We welcome Ofgem's acknowledgement that the treatment of ERDCs was not clear in previous price controls and that it was efficient for companies not to make contributions to pension schemes that were not needed at the time. EDF Energy still believes that the only objective and sound regulatory assumption that Ofgem can make is that previous price controls made allowance for all the contributions actually made. Our position remains that ERDCs should be allowed in full.
- Our response refers to further detailed analysis we have conducted to improve the accuracy of the price controlled/ non-price controlled split of pension liabilities. This more thorough analysis increases the allocation to distribution for SPN and LPN compared with the currently proposed figures.

We recognise that the outstanding issues will require considerable joint effort by us and Ofgem to fully resolve. We are absolutely committed to playing our part in achieving such resolution and we look forward to the continuing ongoing dialogue.

Attached is our detailed response, which we hope you find an informed and helpful contribution to the review and forthcoming discussions.

If you have any questions or comments on this response, please do not hesitate to call me on 020 7752 2114 or Paul Delamare on 0797 1152317.

Yours sincerely,

A handwritten signature in black ink, appearing to read 'Paul Cuttill', is written above a solid horizontal line.

Paul Cuttill
Chief Operating Officer - Networks

Timetable and consultation process

EDF Energy has strong concerns regarding a number of key aspects of Ofgem's conduct of the current price control review and does not believe that its process has been sufficiently robust for it to be able to demonstrate the fulfilment of its relevant statutory duties.

Use of evidence

In order to be able to demonstrate that it has fulfilled its statutory duties (particularly with regard to protecting the interests of existing and future consumers, to financing the functions of licensees, and to the physical environment) Ofgem is obliged to consider relevant evidence submitted to it. EDF Energy believes important elements of its submissions have not yet been given the level of due consideration by Ofgem, necessary for it to demonstrate that it has met its obligations. In particular:

- Our Base Case submission on capital expenditure, which is vital to the interests of our current and future customers, has been the subject of a superficial review/modelling by Ofgem's consultants with the result that many genuine and important investment drivers have simply been ignored.
- The results of PB Power's own model have been discarded in a number of key areas for some companies, but not others. Ofgem should clearly state how such an approach is consistent with its statutory duties to protect consumers' interests.
- We consider PB Power's view of the amount of capex required to be inconsistent with our general duty to develop and maintain efficient, co-ordinated and economical systems of electricity distribution¹.
- Our DNO case submissions, which set out our views as to what improvement our customers want and what we can deliver to them, have not been considered.
- Our detailed evidence of regional cost factors² has also been largely ignored despite the obvious relative cost disadvantage for DNOs operating in the South East/Greater London area.
- Evidence of significant accounting differences between the DNOs (which Ofgem acknowledges in its paper) have been ignored when setting cost allowances that require full catch-up to the frontier (upper quartile) level.
- Evidence of long term capital substitution (opex/capex trade offs), particularly with regard to SPN, has been ignored. This results in the absurdity of the lowest

¹ Refer to Paul Delamare's letter to Martin Crouch dated 30th July 2004 for more details on the rationale for this assertion.

² We have provided, in the Oxera Report, compelling evidence of the regional factors increasing our costs, and believe that due allowance of the clearly higher Greater London cost drivers must be made in the benchmarking. For the record, Ofgem was sent Oxera's report on regional cost factors in December 2003. To date, EDF Energy has not received any comment from Ofgem on why it has chosen to ignore this compelling evidence.

price DNOs³ being regarded as some of the least efficient companies in Ofgem's benchmarking.

- Ofgem is asserting, through its top-down benchmarking, that three explanatory variables explain all cost differences (with respect to the upper quartile companies) despite it having no evidence to support this contention. Furthermore, Ofgem is also asserting, without evidence, that a fixed relationship between these variables is equally appropriate to all DNOs including the highly urban LPN and the very rural SSE - Hydro.

Ofgem still has time to rectify these significant defects. In particular, we recognise a number of steps it is currently taking. However, it is essential that its actions in the coming months represent a proper consideration of the evidence put before it. The main actions we expect to see are:

- A detailed response by Ofgem to EDF Energy's critique of PB Power's work, together with revised capex allowances;
- Proper consideration of DNO Case capex submissions;
- A detailed response to Oxera's paper on regional cost factors and the incorporation of adjustments into all relevant aspects of Ofgem's cost assessment processes;
- A clear, robust and unambiguous definition of the accounting practices underpinning Ofgem's proposals;
- Use of evidence based scale variables within Ofgem's top-down benchmarking; and
- Use of a properly constructed total cost function model.

Remaining timetable

We are concerned that there is no provision for dialogue/iteration after companies have responded to Ofgem's September update document at the end of October. Given the amount of work still required, we consider that it may be ill-advised to prematurely close channels of dialogue between Ofgem and EDF Energy. This is particularly pertinent given that Ofgem's timetable only provides DNOs with three weeks to respond to the September document. We welcome the additional one week response time suggested by Ofgem at the ENA-PCG meeting in July – this does not however negate the need for dialogue once DNO responses have been submitted.

In addition, from the Initial Proposals it is clear that much work remains to be done on critical elements of the price control, including RAV roll-forward, pensions and cost of capital. Ofgem's timetable does not allow significant time for discussion on these critical issues that will shape the DPCR4 proposals. We are concerned that many crucial elements are getting pushed to the back end of the process and DNOs will not be given the time to carefully consider the proposals.

³ Measure by Unrestricted Domestic tariffs

Form, structure and scope of revised price controls

Revenue driver

We support Ofgem's proposal that there will be no volume driver attached to EHV revenues for the next price control period.

It is sensible that Ofgem should update the weightings for the unit driver, since this has not occurred since 1990. We have no issue with the weightings Ofgem proposes for EDF Energy's DNOs in Table 3.1.

Ofgem has previously stated that new EHV sites will continue to be treated outside the price control – which we welcome, as it would be difficult to identify a relevant cost driver to manage such changes in costs. Table 3.5 (page 27) needs to be updated to reflect this view.

Price index

We welcome Ofgem's proposal for the continued use of the Retail Price Index (RPI) since we consider that it best reflects the true inflationary pressures on DNOs.

Units distributed out of area

We agree that requirements on DNOs, with respect to units distributed out of area, should be similar to requirements on Independent Distribution Network Operators. We also agree that any revenue associated with distributing units out of area should be treated as an excluded service item.

Business rates

We welcome Ofgem's recognition that DNOs have put in substantial effort with the Valuations Office Agency regarding business rates and that some DNOs (including EDF Energy) have secured significant reductions from the initial values proposed to reduce prices. We are encouraged that Ofgem is not proposing any disallowance of rate costs and seek confirmation that this will indeed be the case.

Revenue protection

We are concerned that the future arrangements and obligations for revenue protection services remain uncertain with the discussion and consultation process potentially overrunning the DPCR4 timetable.

We believe that DNOs should recover their revenue protection costs from suppliers (as they are responsible for robust metering and data collection arrangements within the settlements process), and that the best way of treating such revenue is as an excluded service. This recognises both the variable nature of work volumes and would facilitate service providers in offering a variety of services to meet market needs.

Allocation of costs for the incentive mechanisms

It seems to us that one of the biggest flaws in the DPCR Initial Proposals is revealed in paragraph 3.25 of Ofgem's paper. Despite not having robust definitions of capex and opex, Ofgem proceeds to place undue weight on opex regressions in producing

aggressive proposals for opex allowances. However, it is hard to accept Ofgem's statement that the development of robust definitions by November is not achievable.

Nevertheless, it seems certain that the opex numbers used in the regressions have not been cast using consistent definitions. It would not be acceptable that any such differences could give any DNO an unfair advantage/disadvantage (which would clearly not be in customers' interests). It is essential that there should be standard definitions that all companies use from next April.

Ofgem states that "much of the strength of opex incentives is derived from the comparative assessment of efficiency at the price review, and this would not be affected" by the fact that capex and opex are not well defined. In practice, most of the incentive for opex efficiency is more short term and derives from the price cap incentive to raise profits by cutting costs. However, Ofgem will not provide incentives for DNOs to choose efficient cost levels so long as the revenue allowances, built into price caps, are driven at each review by unpredictable benchmarking exercises using non-comparable costs. In fact, Ofgem may drive DNOs to select inefficient investment (because it enters the RAB according to broadly defined rules) rather than opex (which is subject to subjective benchmarking exercises). Clearly, if Ofgem continues to base opex targets on one or more frontier companies, the accounting treatment of opex used by that company will profoundly affect the opex allowances of the other DNOs. We know of no mechanism whereby any opex "deficiency" resulting from this will be added to a company's capex allowance.

Ofgem may believe that its proposal to equalise capex and opex incentive reduces the impact of problems with capex and opex accounting definitions. However, as we note above, so long as there is separate treatment of capex and opex in benchmarking and in rolling forward the RAB, this cannot be the case.

We also note (under our response to Ofgem's sliding scale mechanisms) that the equalisation of opex and capex incentives cannot be achieved unless respective overspends are given equal treatment. Since we regard it as unlikely that Ofgem would allow the recovery of opex overspends (in most circumstances) there will remain an incentive to capitalise opex. Thus it cannot be possible to equalise incentives and nor can it be appropriate to agree to a price control that is not accompanied by clear and robust accounting definitions and rules.

We also note that (as Frontier Economics found) most opex savings tend to be enduring, whereas most capex savings tend to be one-off deferrals. The differential incentive rates implied by the mix of these will be hard to equalise. We have not seen Ofgem's proposals for achieving these and would ask that details be provided in the proposed September document.

It is therefore essential that Ofgem sets out in detail the accounting policies that underpin its proposals, and demonstrates how they are implemented by the frontier companies such that all other companies can ensure that they are (or will become) aligned with these.

Dealing with uncertainty

EDF Energy supports the ENA paper recently submitted on uncertainty “Dealing with Cost Uncertainty and New Legal Obligations”, July 2004.

Losses

We welcome Ofgem’s increase in the losses incentive rate. However, this increase on its own will not make it viable for companies to invest in low loss equipment. This is because it will take significant penetration of low loss equipment into the network for its impact on losses to be observable. Therefore, it is essential that additional expenditure on low loss equipment is added to the RAV.

Ofgem has stated that if additional capital expenditure incurred to reduce losses meets the traditional efficiency criteria, then it will be allowed to enter the RAV. We are unaware of any definition of these traditional efficiency criteria and would ask that Ofgem set out an appropriate definition. If this is not done then companies will still face regulatory uncertainty over whether such investment will be added to the RAV.

We are also concerned that companies may be penalised under the proposed sliding scale mechanism for capital expenditure. Companies’ allowances are based on PB Power’s assessment of their capex. PB Power’s analysis has only considered Base Case capex. Therefore, if a company decides to invest in low loss equipment, which was not included in the Base Case forecast, it will face the risk that Ofgem may deem that such expenditure does not satisfy Ofgem’s uncertain eligibility criteria.

Our acceptance of losses targets is on the basis that our existing rights and responsibilities for revenue protection activities are not curtailed. Otherwise targets will need to be modified. Our acceptance of losses targets is on the basis of provisions for revenue protection being in place. A specific re-opener is therefore required of at least the same as in the current price control.

Incentive rates should be inflation adjusted (by RPI) going forward, in line with current practice. We ask that Ofgem clarifies that this is the case as it is not entirely clear from the Initial Proposals.

To reduce risks, EDF Energy needs a clear view of how the losses incentive mechanism will work on a long term basis. We therefore consider that Ofgem should inform DNOs of the targets for 2010 before the start of DPCR4.

Ofgem is proposing a minimum loss adjustment factor (LAF) of 0.997, although it would be more appropriate to set the minimum level to 1.00, so that no losses caused by distributed generators are paid for by DNOs. We welcome Ofgem’s movement toward this point.

The current minimum LAF allowed for a SVA LLFC under the Balancing and Settlement Code (BSC) and its associated BSC Procedure is 1.00. To correctly allocate losses to

distributed generators by allocating LAFs below unity, either a change proposal or a BSC Modification will be required.

Metering

We note that Ofgem and the DNOs have made considerable progress in determining the scope and nature of a metering price control. However, the lack of transparency over the methodology of calculating the numbers has made it difficult to have a clear understanding of what has actually been proposed. In particular, it is currently impossible to say with any certainty from the Initial Proposals what the ongoing metering revenue will be. Thus it has made it difficult to calculate what the overall revenue for the distribution business is. Ofgem should aim to provide a detailed audit trail in the September update paper at the latest.

MAP price control

We welcome Ofgem's overall approach with regard to the MAP price control by keeping it simple while protecting customers' interest. However, we are concerned with some of the detailed logic that has been applied to calculating the price caps. The issues include:

- **Differential price caps:** By having differential price caps between DNOs, Ofgem is not encouraging competition but is distorting it. There should be a consistent price cap for all distributors (based on the highest amount), otherwise distributors with a low price cap may be forced to supply meters at their capped price (for use out of area – which the DNO could not prevent). A single high price cap (based on the highest cost meter) will allow and encourage competition, whereas setting multiple price caps will simply distort demand towards the meter provider with the lowest price cap based on the cost of existing meters, regardless of the cost of installing a new one.
- **Cost of capital:** The cost of capital that has been used in the calculation of the price caps is based on the weighted average cost of capital for a distribution business (low risk). This is unacceptable as it does not take account of the risks faced by distributors under the new metering market conditions which have been created by Ofgem. Therefore the only option open to DNOs (to have some certainty over the recovery of cost and the provision of market economic signals) is to impose a termination charge if the asset is replaced before the end of its certified life.
- **Meter definition:** Ofgem should clarify whether the price cap be associated with a particular type of meter or the functionality of the meter i.e. will a multi-rate meter set at a single-rate status be subject to the price cap?
- **Prepayment meter technology:** As it is the dominant supplier who effectively sets the prepayment meter technology in the distribution area surely it (i.e. the supplier) is in the best position to assess the levels of quality and cost of any particular technology required. Therefore it seems appropriate that DNOs be allowed to inform such a decision (provision of economic signals) by specifying the costs of making a particular technology redundant (stranded). This, as pointed out above, could take the form of a termination charge.

- **Licensing Issues:** Ofgem's desire to promote competition in metering stems from a concern that ownership of meters may give incumbent suppliers some advantage. Ofgem has not yet explained, however, how transferring responsibility to another provider will not simply transfer that advantage. Since some alternative providers may be unlicensed entities, Ofgem would then have no powers to constrain their use of this advantage. We would therefore welcome an explanation from Ofgem as to how competition will operate in the long-term.

MOp price control

We are disappointed that Ofgem felt it necessary to publish Table 3.4 (Metering Opex Costs). The information in the table, as pointed out in the Initial Proposals, does not reflect the true level of MOp cost and is unhelpful. Publishing inconsistent data only clouds the issue.

The normalisation issues surrounding 2002/03 MOp costs pose a problem and we feel it may be easier to offer simple price caps for a selected number of services which could include:

- Installation of a single rate, single phase credit meter, and
- Installation of a single rate, single phase prepayment meter.

The stranded MOp cost associated with the loss of market share could then be recovered through the distribution use of system charge. The remaining services would remain outside of the MOp price control and be covered by non-discrimination clauses.

Basic service

It is important that a clear definition of what is required as part of a basic service be agreed as soon as possible as the current contracts (the "JPW" agreements) between suppliers and distributors are dated and do not take account of the new metering service market.

The basic service contract should include a clear and detailed list of services and service levels for MOp and MAP.

We are particularly concerned with the ongoing timetable of the project as it will be very difficult to draft tender documentation and negotiate new terms with service providers which will allow us to meet our modified regulatory obligations by April 2005.

One way door

We welcome Ofgem's proposal that the one-way door be defined in relation to individual premises or customers. It would also be sensible to have the obligation lifted if only a "rump" of meters remain in respect of a particular supplier, since these could be relatively high cost meters provided at a loss by the DNO. Such a subsidy would not be in the interests of promoting effective competition.

Long term switch-off

We welcome the acknowledgement by Ofgem that the obligations should be lifted as soon as possible.

As to the retention of the obligation for existing assets, we require clarity over whether the obligation will apply to the actual assets or existing contracts. If it is the latter then DNOs may be indefinitely held to providing MAP under regulatory conditions.

Quality of service and other outputs

Summary of results from the consumer survey

Ofgem's survey indicates that customers are willing to pay significant sums for improvements in quality of service. However, even given the need to moderate the results of the survey, it indicates a willingness to pay for quality improvements that are somewhat higher than Ofgem's DPCR3 allowance of £2.30 per customer per annum.

We accept the indication that customers value improved restoration more than reductions in frequency. As a result, Ofgem has made an opex allowance for improved restoration performance. This does not imply, however, that customers do not highly value capital investments, such as remote control and automated restoration, which achieve both. Whilst Ofgem has made an explicit Opex allowance for restoration improvements they should explicitly recognise that capex solutions represent a valid alternative.

Revenue exposure to quality of service incentives

If Ofgem believes that the willingness to pay justifies increased incentives, this should also be reflected in allowances.

By reducing QoS allowance (compared to DPCR3) Ofgem is effectively offsetting the increased rewards available to a DNO, seemingly contrary to customers' wishes (i.e. the net incentive is reduced). In addition, if incentives are to be increased then there should be an equal opportunity to outperform as there is to be penalised. Whilst we welcome Ofgem's recognition of the need to limit the downside risk, there is, in general, significantly less scope, given the significant levels of challenge implied by the targets, for out-performance rewards than there is for penalties.

Ofgem needs to achieve an appropriate balance between cost allowances, performance targets and incentive rate.

Standards of performance

We support Ofgem's proposals to allow direct payments to customers, to maintain the existing arrangements for business customers and the removal of Overall Standards with the introduction of equivalent reporting.

We are concerned about Ofgem's proposal to reduce revenue by the amount of unpaid Guaranteed Standards. We understand Ofgem's intent but we believe that this creates little incentive for companies to incur the costs of pro-actively directing compensation to customers (i.e. there is a positive incentive to avoid administration costs). We support actively making customers aware of their right to compensation under the Guaranteed Standards arrangements. This approach should be pursued before resorting to the measures Ofgem proposes to introduce.

Severe weather arrangements

We support the decision to remove the materiality threshold of the existing scheme. We believe that companies' revenue should only be reduced by the amount of unpaid compensation where companies cannot demonstrate that they have made reasonable efforts to inform customers of their rights to compensation.

Interruptions incentive scheme

We fully support a symmetrical incentive mechanism that excludes the effects of severe weather. The targets around which such a scheme operates must present an equal risk of failure or opportunity for out-performance, particularly where normal weather related variability is significant.

The weightings on the number of customers interrupted (CI) and the duration of interruptions (CML) incentives appear consistent with the findings of Ofgem's customer survey. I.e. that customers value reducing the duration of interruptions more highly than reducing interruption frequency.

We understand Ofgem's intent in reducing the weighting of planned interruptions to increase the incentive to undertake planned activities (i.e. to avoid unplanned interruptions). We fear that this has a distinct drawback in practice. Ofgem has reduced the absolute levels of allowed planned CI and CML consistent with this weighting. For companies with very low existing levels of planned CI and CML, should it exceed, or be likely to exceed, its unplanned CI or CML by a small amount (very possible where improvement target is challenging), the headroom to undertake planned work to avoid failing targets would be significantly reduced. For example, one unplanned CI or CML over target will reduce the scope for planned activity by two CI or CML. Ofgem should reconsider this issue.

Setting Targets

We recognise that the use of disaggregated data for determining HV benchmarks is an improvement on past processes. However, we remain disappointed that Ofgem has been mechanistic in their use of the data and did not enter into a dialogue with individual DNOs to understand the differences this revealed, in particular:

- Average Customers per circuit is inherent/inherited in network designs and expensive to change
- Average Fault Rate is inherent/inherited due to operating environment and duty over many years and is expensive to change

The benchmarking conducted for LV performance, based on an average CML/CI restoration index, remains simplistic. It is an area for further work between Ofgem and EDF Energy, particularly given the impact on the performance benchmarking for LPN. We are also concerned that the considerable differences in the levels of planned CI and CML, particularly with respect to the benchmark DNO networks, have not been explained.

As we have stated before, for the incentive mechanism to work as intended, there must be an equitable opportunity to outperform CI and CML targets. We recognise that Ofgem has tried to address this using three year average starting points. However CML targets based on upper quartile performance represents an unreasonable target for companies with a lower level of performance. Whilst the average performance in recent years is demonstrably achievable, upper quartiles and similar targets have no objective basis in fact. Expecting companies to improve performance quickly is unreasonable, given the high cost of reconfiguring the network. Attempts to impose targets based on above average performance are unlikely to reflect an equal

opportunity to outperform, unless the improvement in underlying performance and variability due to weather is fully funded to make this so. Ofgem's current proposals do not achieve this.

Ofgem needs to justify its asserted 0.5% per annum improvement above its benchmark. This corresponds to a 3% improvement over the DPCR period. No analysis has been presented to support its feasibility taking into account historic trends in output performance, network reliability and changes in technology.

A similar justification should be presented for the 40% catch-up to the 2020 benchmark by 2010. Ofgem has not explicitly assessed whether the differences in performance are related to inherent differences in network fault rates that may not be readily or cost effectively rectified.

Allowances

During our meeting on 5th August (with Chris Watts), we highlighted a number of concerns with Ofgem's methodology for determining allowances. At that meeting, we agreed areas that need further investigation and clarification by Ofgem. In addition, we agreed to share our methodology with you for determining our Quality of Supply expenditure. We believe that Ofgem's interpretation of the information we have provided in Table 15 (FBPQ) has resulted in an incorrect investment allowance. We are also concerned that Ofgem's approach continues to assume a linear relationship between investment and output performance (i.e. Ofgem is ignoring the stepped nature of QoS improvement programmes) after the valuable work that has been undertaken in conjunction with the DNOs.

Ofgem has also given little or no consideration to the DNO investment scenarios. Furthermore, the impact of changes to the Base Case capex positions through discussions with PB Power and Ofgem have not been considered in the QoS allowances. Ofgem cannot treat QoS investment as something detached from the Base Case capex assumptions put forward by companies. Such an approach would be irrational. Our DNO case contains significant capex needed to achieve symmetrical risk in the incentive scheme.

In making an opex allowance for restoration performance, Ofgem has used a single DNO's data to determine their £200 cost per fault allowance. This selection of a single atypical benchmark is not consistent with sound regulatory practice. Ofgem must consult further on what this value represents and determine an appropriate value for each DNO relevant to its circumstances. We also believe that Ofgem is wrong to imply only opex solutions to restoration speed improvements and consider that Ofgem's implicit model must be discussed further. Furthermore an opex allowance for restoration should be based on each company's number of faults, as neither the Base Case replacement capex nor QoS CI improvement capex allowances will be sufficient to allow companies to move to the benchmark number of faults used to calculate the restoration allowances.

We will work with Ofgem to come to an acceptable position in time for Ofgem's further proposals.

Rewarding best practice in quality of supply

Ofgem has proposed a best practice reward (1% of revenue per annum) for WPD South West and WPD South Wales, being companies having “very good” average restoration time performance. Such an ex-post reward has no effect on incentives (either in past years or in the future) and merely represents a windfall for WPD paid for by customers. We doubt that, legally, Ofgem is in a position to make such an award when it cannot be in consumers’ interests and may involve unjustified discrimination between DNOs.

If such rewards are to be granted, we believe that there is a strong case for rewarding the excellent achievements of LPN. Such a reward should also recognise the importance of not interrupting customers in the first place and should not focus solely on restoration. LPN has made significant improvements (an 18% fall in CIs between 2001/02 and 2003/04) from an already frontier level of CI performance⁴. Ofgem has nowhere explained why WPD’s performance is worthy of a special reward, whilst LPN’s is not.

To reward restoration performance only would ignore LPN’s achievements and would distort incentives (as already recognised in the IIP scheme). Using Ofgem’s levels of improvement required⁵ to identify the frontier performers, a combination of interruption and restoration measures strongly suggests rewards for WPD South West and EDF Energy – LPN, even after taking account of a higher weighting given to CMLs over CIs in the IIP incentive scheme (1.8:1.2 respectively). The table below shows the target improvements proposed by Ofgem based on disaggregated quality of supply data.

	CI Improvement	CML Improvement
WPD South West	0	0
EDF Energy – LPN	0	1
SSE - Hydro	0	2
WPD South Wales	6	0

We believe that the improvements in CI and CML performance that have been achieved in LPN’s area represent the reference for HV performance. LPN’s investment in network remote control and automatic restoration systems will allow this performance to be sustained.

Whilst we accept that the LV restoration performance in London does not match that of WPD, Ofgem has not attempted to undertake an LV benchmarking exercise that reveals the reasons for differences in LV restoration performance. We recognise that it is a complex issue and, for many DNOs, represents a small part of their overall performance, but this must be an area of future work between the DNOs and Ofgem if it is to be benchmarked in this fashion.

Setting incentive rates

We support Ofgem’s top-down approach but are concerned that weather related effects present an increased risk of penalties over the opportunities for rewards. High

⁴ Assessed using Ofgem’s disaggregation method – page 38 June 2004 Initial Proposals

⁵ Pages 38 and 39 June 2004 Initial Proposals

bandwidth gives low incentive rates for companies with large absolute performance outputs. This makes significant rewards for out-performance difficult and creates a dilemma that requires further consideration.

Audits and accuracy

We support Ofgem's proposals to simplify the audit process, although Ofgem needs to give consideration to the cost of self-audit.

We do not believe that the case has been made for the benefits or necessity of increasing accuracy targets from 95 to 97 percent. This would not make a significant change to reported CI or CML, is not a necessity for the incentive mechanism and would require greater audit rigour to maintain. If Ofgem accepts that errors will cancel out over time in a symmetric incentive scheme, there will be no need to adjust for accuracy.

In all we believe that improving the audit process is more important than changing accuracy standards at this time.

Frontier performance for this price control period

We agree with Ofgem that the frontier performers should be eligible to participate in the reward mechanism in respect of 2004/05. Clarification of this in relation to the IIP licence conditions, i.e. that this is supplemental, would be welcomed.

Storm arrangements

We support the decision to remove the requirement for materiality. At present the main concern that remains is over the "gate" for very large events. We would ask that Ofgem confirms that the number of customers includes those who have been affected by EHV events in these circumstances. Ofgem's mixed and overhead circuit definition will exclude many customers who are supplied by EHV overhead networks who could be affected by a very large event.

The magnitude of the 'gate' number of customers is presently too high. Setting a lower gate would not prejudice Ofgem's discretion and could be done in such a way that the majority of severe weather events are captured in the scheme, but very infrequent large events, such as October 2002, that are likely to require review by Ofgem to satisfy stakeholder concerns, clearly exceed the 'gate'.

When the interim arrangements were developed, and throughout the subsequent discussions leading to these proposals, Ofgem specifically expected snow and ice, flooding or similar conditions that persist and restrict access to the network to be excluded from the scheme. We believe that this should be explicit in the new arrangements (rather than implicit from the note to Table 6 of the appendix) as there would be a need for Ofgem to review each case. This would not prejudice Ofgem using the arrangements as a benchmark in its assessment. Ofgem needs to be explicit in respect of the scope of its proposals with respect to any modifications to the GS exemption statutory instrument.

We believe that further work is required by Ofgem to explain the per customer allowances used to determine the exceptional event allowances, and the assumptions that have underpinned this. We do not believe that it is sufficient for Ofgem to assert

that it is up to companies to decide how to use the allowance without Ofgem stating its assumptions. The proposed allowance is currently insufficient to allow for storm insurance or for significant resilience mitigation.

Incentives for the speed and quality of telephone response

It is our opinion that Ofgem should set a minimum level of absolute performance that is not the 'average minimum' that is currently achieved, but is commensurate with good customer service, presently defined as a score of 4 or above. The penalty regime should then be spread between good and acceptable performance i.e. between a score of 3 and 4.

Ofgem's customer survey has indicated a difference in expectations for ring-back services in London. Ofgem has still to undertake an assessment of regional differences in customer expectations. We continue to consider this an essential study before incentives are increased in this area, especially given their asymmetric nature.

Scores on new questions, such as those relating to speed of response, should not be incentivised until results over a period of time have been shown to be reliable.

With regard to a telephone response survey following severe weather, we believe that this should be developed and trialled before any decisions are taken to place revenue at risk. The survey must be robust enough to ensure consistency between events if it is to have any real value in improving customer service.

Undergrounding in areas of outstanding natural beauty

Undergrounding for amenity value and for resilience should be considered further in discussion with the DNOs as part of the development of the Initial Proposals. Ofgem should also consider DNO Case proposals.

Environmental reporting

We will work with Ofgem to finalise the definitions for the indicators for these reports.

Discretionary Award

We support the development of a comprehensive stakeholder survey taking a balanced view of the service offered to all stakeholders. We believe that the panel should be independent of Ofgem and the DNOs and should represent a cross section of stakeholders. For example, it should include customer representatives (large and small), demand and generation, local and national government and wider community agencies.

The assessment process for the reward must be robust and transparent.

Distributed generation, the innovation funding incentive and registered power zones

Introduction

We welcome the publication of:

- Further details of how the distributed generation incentive, innovation funding incentive and registered power zones mechanisms will work;
- Ofgem's initial views on relevant licence modifications; and
- The draft Regulatory Instructions and Guidance (RIGs).

We have some detailed comments on the content of the Appendices to the Initial Proposals document⁶, which we have included in Appendix A to this response.

Innovation funding incentive

The innovation funding incentive continues to have our full support and we strongly welcome the proposal to initiate IFI projects before 2005/6. As you have requested, we confirm our wish to start such projects before the beginning of the next price control period (i.e. between the 1st October 2004 and 31 March 2005). However this is subject to satisfactory assurances in regard to the recovery of the expenditure associated with such projects. This will be necessary as changes to the distribution licence covering the IFI scheme will not be in place over this period and it is unlikely that the good practice guide will have been completed and approved until well into it. Therefore we will need to have a clear understanding of the arrangements that will apply during this period so that we can have sufficient confidence in the cost recovery mechanism to allow the appropriate expenditure to be authorised. This is an issue of some urgency as there is a lead time necessary to plan and initiate suitable projects.

In the meantime EDF Energy intends to be an active participant in the production of a good practice guide for managing R&D projects.

Registered power zones

The position with RPZs continues to be somewhat problematic. Whilst we welcome the proposal to increase the incentive rate from £3 per KW to £4.50 per KW and recognise the significant enhancement that this brings to the attractiveness of the scheme, we are also still concerned about its rigidities and constraints. For example, the proposal to limit the scheme to two RPZ applications for registration per DNO per year seems arbitrary and restrictive. It is proposed that this restriction is lifted and replaced by a two stage application process. The first stage would be a simplified high level submission which would enable Ofgem to provide an initial response on the extent to which the project was likely to be able to meet RPZ requirements. This would weed out unsustainable projects at a relatively early stage, thus avoiding unnecessary costs for

⁶ Appendices – further details on the incentive schemes for distributed generation, innovation funding and registered power zones, regulatory instructions and guidance, structure and scope of price control modifications

both Ofgem and DNOs. A second stage full application would then be required before the project could be finally registered.

Draft Regulatory instructions and guidance, further details of DG/IFI/RPZ incentive schemes, and draft licence modification appendices

Our detailed comments on the following documents are set out in Appendix A:

- Draft Regulatory instructions and guidance;
- Further details of DG/IFI/RPZ incentive schemes; and
- Draft licence modification appendices.

Operating costs

Overview

Ofgem states that “the existing boundaries between capex and opex are not well defined and that the development of robust definitions is not achievable by final proposals in November”, and that DNOs can deliver “efficiency savings by reclassifying costs”⁷. We agree that material accounting differences remain between DNOs with regard to the normalised costs used in Ofgem’s cost benchmarking. In particular, we believe that significant differences remain in the areas of overhead capitalisation and replacement capex. We do not share Ofgem’s pessimism regarding its belief that these problems cannot be resolved by November.

It is essential that price control proposals must be accompanied by a clear and detailed statement of the accounting rules which underpin it and which must be employed by all companies from 1 April 2005. There are two important reasons for this:

- Capex and opex are the subject of separate benchmarking exercises at this review (and no doubt will be at subsequent reviews);
- It is not possible to equalise the treatment of opex and capex overspends (and therefore it is not possible to equalise incentives) during the price control period⁸.

It would be difficult for Ofgem to argue that robust accounting definitions cannot be identified in time for the final proposals. After all, all that is required is for Ofgem to investigate in detail the accounting practises used by the frontier companies (just 2 or 3 companies), a process that would take just a few weeks to complete.

It is entirely plausible that the differences between EDF Energy companies and those on the frontier/upper quartile are entirely due to unresolved accounting differences.

Faced with benchmarking that Ofgem knows to be less than robust, Ofgem has nonetheless proposed that companies achieve upper quartile company cost levels, i.e. implicitly assuming that 100% of the residual differences are attributable to inefficiency⁹, when in fact it has already admitted that some of the differences are due to data definition problems. The policy intention here appears to be that since DNOs have failed to collectively agree a robust data definition framework, the risk of inadequate price controlled revenues is wholly theirs. Such a position ignores the fact that poor standardisation of accounts will benefit some companies and penalise others, thereby making agreement on common standards even harder to attain. Ofgem ran an extensive regulatory accounting project over a number of years in the context of very significant statutory powers to require information from licensees (but put insufficient effort into producing clear definitions of activities and the method of accounting for activity costs). It would be quite unreasonable to attempt to put the consequences of the failure of this project on the shoulders of the DNOs. In particular, such a policy

⁷ Para 3.25 June 2004 Initial Proposals

⁸ We explore this further under our comments on the sliding scale mechanism

⁹ Ofgem may argue that using the upper quartile level already allows for some error in the model. This is partially true to the extent that Ofgem has removed SSE-southern – a DNO with unusually low cost.

would be inconsistent with Ofgem's duty to "secure that licence holders are able to finance [their] activities"¹⁰.

Ofgem is also, of course, implicitly assuming that its composite scale variable (CSV) fully explains the impact of both scale differences and acts as a complete proxy for the underlying "real" cost drivers DNOs face. Asserting that the differences are wholly attributable to inefficiency is not credible. Indeed, we are unaware of Ofgem carrying out any detailed analysis of cost drivers/scale variables¹¹, which would imply that Ofgem had in fact no robust understanding of the accuracy of its benchmarking model. An appropriate course of action for Ofgem in these circumstances would be to carry out a detailed analysis of cost drivers and scale variables in order to create credible cost functions. This would enable it to demonstrate that its proposals were consistent with its financing duty.

Where Ofgem can improve its modelling in other ways (which we discuss further below) it is compelled to do so as this would further the achievement of its statutory objectives:

- Model data from both 2002/03 and 2003/04 to reduce the effect of year on year variability;
- Properly account for regional differences in input prices;
- Decompose the residual values to reveal the error term;
- Use of a properly constructed total cost function model.

In order to demonstrate compliance with its financing duties, Ofgem should be clear about how accurate its benchmarking is. For example \pm £5m, \pm £10m \pm £100m etc? The price control proposals should reflect this range.

Ultimately, Ofgem must accept that the results from a poorly specified benchmarking model do not provide a proper basis for setting revenue allowances.

Annual data collection

We would support moving to a system of annual data collection based on standard cost/activity definitions. Such a system of data collection must be robust and in particular must address:

- Fault/Replacement boundaries
- Classification of costs as direct
- Capture of indirect costs in third party "direct" costs

Use of 2003/04 data

Econometric cost benchmarking studies will produce more precise parameter estimates and model predictions the larger and more varied the sample on which the estimates

¹⁰ S3A Electricity Act as amended by the Utilities Act 2000

¹¹ Ofgem did carry out a high level analysis as part of DPCR3, but does not appear to have repeated this exercise

are based. In particular, larger sample sizes permit the decomposition of residuals into error (noise) and other elements. Sample size can be augmented by including data for more years for the same companies. Ofgem can and should augment its benchmarking analysis with 2003/04 data. EDF Energy is prepared to take a full part in any work necessary to normalize this data. We assume other companies would be in the same position, unless of course they expected a windfall from the vagaries of Ofgem relying on a single year.

We note that in its Initial Proposals¹² Ofwat has made some allowance for the underlying error in residuals. Ofgem will need to justify, with reference to its statutory duties, why such an approach should not be used in electricity distribution.

Regional salary costs

Regarding the input price specification, there is considerable variation in labour prices across Britain. Generally speaking, labour prices are highest in London and its suburbs and lowest in the North East and Wales. Prices of other operating inputs are also likely to vary regionally, albeit by smaller amounts. A failure to account for regional input price variation will therefore result in biased parameter estimates and model predictions. Parameter estimation bias will be greatest for variables that are correlated with the labour price, like undergrounding and service quality.

Ofgem’s control for regional labour price variation is at best crude. An adjustment was made to the costs of EDF Energy-London in recognition of the substantially higher labour costs in its service area. This remedy plainly is not the best possible correction for the variation in labour prices across Britain.

Ofgem’s process for addressing regional costs is also inconsistent regarding the treatment of different cost categories:

Cost category	5yr allowance (%)	Treatment
Opex plus faults	£30.5m (12%)	Broadly in line with DPCR3 adjustment
Non load related capex	£89m (31%) ¹³	Certain unit costs uplifted – but not all
Load related capex	??	No visibility of PB Power’s assumptions

Ofgem notes the substantial Oxera study of the impact on our operations of regional cost factors submitted by EDF Energy but appears to dismiss it in a cursory manner (at paragraphs 6.22 to 6.25). The Oxera study is an expert analysis, derived from publicly available official data, and produced by a highly respected economic consultancy whose market reputation rests on the objectivity and rigour of its work. Because of these characteristics of the study, the burden of proof is on Ofgem to demonstrate, in detail, why Ofgem's proposed cost adjustments should not fully reflect Oxera's quantified conclusions. Having received the study as a formal submission under the DPCR4 process, it is not appropriate for Ofgem to simply replicate, without further

¹² Future Water and Sewerage charges 2005-10, Draft Determinations, Ofwat 2004

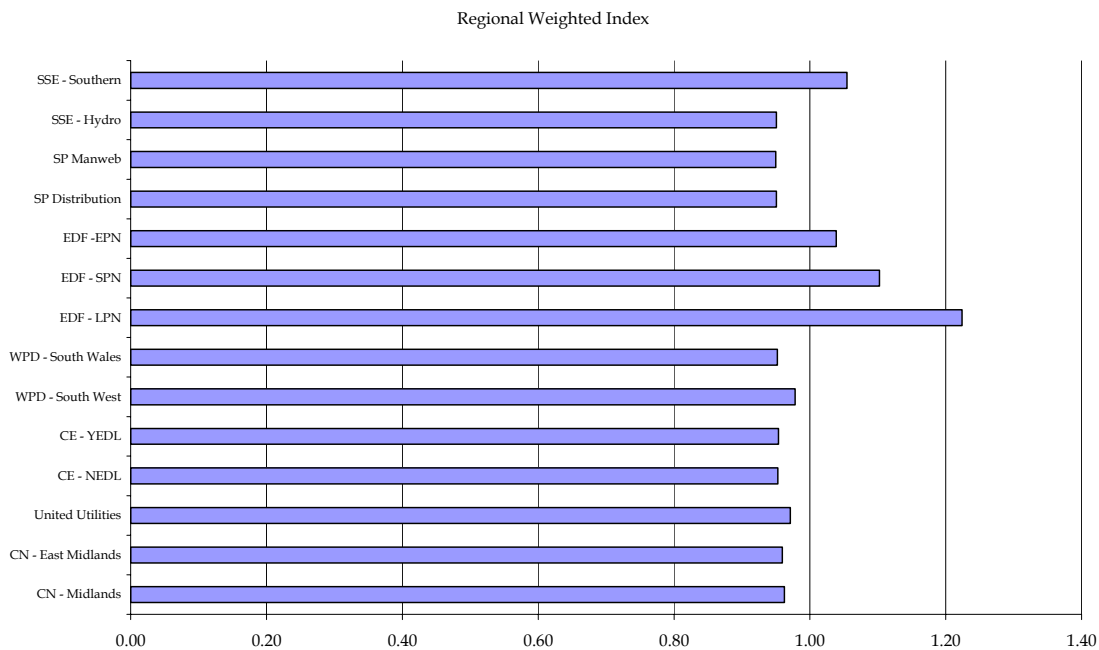
¹³ This may be a mix of exogenous regional costs and engineering complexity

explanation, the restricted scale of the adjustments, for LPN alone, made at the time of the previous review.

Moreover, the observable difference in salary costs is only one of many factors omitted from Ofgem’s analysis. The costs of congestion, visible in higher land rentals, will affect a great many other costs incurred by LPN and, to a lesser extent, by EPN and SPN in south-eastern urban areas served by their distribution networks. These costs of congestion may not be fully captured in the unit cost indices, because congestion increases the *quantity* of time and materials required to address any task, as well as their unit cost.

Ofgem’s failure to properly take account of regional costs for Greater London (for EPN, LPN and SPN) contributes significantly to the erroneous perception that EDF Energy’s DNOs are relatively inefficient.

We have recast Oxera’s evidence into a spreadsheet tool which we have already submitted to Ofgem. The chart below shows this data and identifies the uplift factors. It also reveals that DNOs who set the upper quartile have regionally adjusted costs 5% below the GB average - while LPN’s are over 20% above average.



Analysis of our average salary cost per FTE (2002/03) in London is 34% more than EPN (and 28% more than SPN). Pension costs, car payments and healthcare benefits (including associated NIC payments) are excluded. The percentage difference between LPN and EPN/SPN is shown net of overtime costs since this could distort the picture (i.e. if LPN was considered to be short of staff). However, higher levels of overtime is to be expected in LPN because of operational and equipment access constraints imposed by the London environment.

	Wage costs (£m)	Overtime costs (£m)	Net wage costs (£m)	FTE	Wage cost per FTE (£k)	% Difference
EPN	51.9	6.4	45.5	1665	27.3	36%
LPN	40.6	5.6	35.0	940	37.2	
SPN	38.9	4.5	34.4	1225	28.1	32%

We will also provide Ofgem with evidence of regional cost differentials from our key contracting partners.

Composite scale variable (CSV)

Ofgem's assumption that costs are primarily driven by the scale of the business represented by a particular mix of network length, number of customers, and units distributed underpins its entire "top-down" approach to assessing operating efficiency. Indeed, Ofgem is proposing that all differences between each company's modelled "normalised" operating cost and that of the "upper quartile" companies are due to differences in efficiency.

There are two significant defects with Ofgem's work. Firstly, it has undertaken no detailed analysis on DNO cost drivers (either as part of this, or previous, price control reviews). Secondly, Ofgem's composite scale variable approach to regression analysis relies on fixed weightings between the component variables, even though the mix of underlying cost/scale drivers is bound to vary between the companies. This means that, in Ofgem's model, both LPN and Hydro are given the same weighted mix of cost drivers even though one company has an entirely underground network in highly urbanised conditions, whereas the other is characterised by long overhead line circuits serving rural communities.

We also note that although CEPA's work on benchmarking¹⁴ recommended giving equal weighting to customer numbers and circuit length, its report on TFP used two thirds customer numbers and one third units. Since Ofgem has relied on the latter (p6.37 refers) for its annual efficiency saving target (1% - 2%p.a.) it should explain how it can justify basing its proposals on inconsistent assumptions (i.e. with CSV2).

Simply asserting that all residuals are due to differences in efficiency alone is, in these circumstances, quite wrong and discriminates between the companies - disadvantaging some and creating a windfall for others. Such a simplistic approach, given that Ofgem can easily improve its model/assumptions, and has time to discuss the individual circumstances of each DNOS, is not consistent with its statutory duties.

In our presentation to Ofgem's CSV workshop (5 August 2004) we showed that Ofgem's three scale variables (customer numbers, units distributed and network length) are sometimes relatively poor proxy variables for more fundamental scale variables (including customer density, overhead line circuit length, underground circuit length and maximum demand). We also show through DEA analysis (see table below) how the optimal mix of output variables varies between DNOs (based on the data used in Ofgem's own regressions). Ignoring such evidence is not an option open to Ofgem

¹⁴ Background work to work on assessing efficiency for the distribution price control – Cambridge Economic Policy Associates, Sept 2003

given its statutory financing duties which apply to each individual licensee and not to licensees collectively.

Percentage contribution or output variables to DNO specific optimal efficiency score using DEA

DNO/driver	Customers %	Units %	Network Length %
CN - Midlands	100		
CN- East Midlands	100		
UU	100		
CE – NEDL	100		
CE – YEDL	100		
WPD South West	12.9		87.1
WPD Wales	13.6		86.4
EDF Energy – LPN		100	
EDF Energy – SPN	100		
EDF Energy – EPN	100		
SP Distribution	12.8		87.2
SP Manweb	13.6		86.4
SSE – Hydro	6.5		93.5
SSE – Southern	15.3		84.7

In support of its 50% weighting on circuit length Ofgem notes in p6.32 that its analysis “shows that companies have attributed almost half of operating and fault costs to overhead lines or underground cables, or to wayleaves”. Ofgem’s logic is deficient here, i.e. Ofgem’s apparent assertion that:

- 50% of costs are circuit related; and so
- 50% of opex costs are driven by circuit length;

does not amount to a robust syllogism since circuit costs could be driven by anything but still amount to 50% of overall costs. We do not find this to be a convincing rationale, and neither should Ofgem.

Instead, Ofgem should look for the real cost drivers by looking at the engineering activities required. For example, this would reveal that circuit length related costs for overhead lines opex are restricted to overhead line inspection, pole testing (replacements are capex) and miscellaneous repairs (e.g. to stays and interconnectors); as well as occasional weather related damage.

Tree cutting is regionally specific and relates to tree coverage rather than line length. Pole mounted transformers are not maintained but replaced upon failure (capex). That leaves ABSDs (switches mounted on poles), Pole Mounted Auto Reclosers (PMARs), and HV and LV fuse-gear.

- We do maintain ABSDs. These are installed along OHLs at intervals of roughly every 1,000 KVA (or so) of connected transformer capacity (for P2/5 purposes) so the nearest equivalent variable is obviously load.
- PMARs are installed partly on a per km basis and partly on a per customer/load basis. But they are maintenance free and so don't generate opex. If they fail, we replace them (capex).
- Fuse-gear maintenance is negligible; replacement (opex) is on failure and included in faults costs. HV fuse-gear is somewhat related to numbers of transformers, and LV fuse-gear is directly associated with PMTs, so the nearest equivalent variable for both is customers (or load).

Other rural opex drivers include ESQC matters – like anti-climbing guards (repairing and replacing). We don't install these on intermediate poles (i.e. poles that are just there to hold the line up) we install them on poles that contain plant. Hence they are customer (or load) driven – not line length.

Total cost analysis

To be a minimum cost function, the model must either feature total cost as the dependent variable or, if operating expenses is the dependent variable, feature instead a capital quantity index as an explanatory variable. However, Ofgem's modelling assigns all inefficiency to operating/fault costs.

There is evidence from several sources to suggest that this deficiency of the proposed Ofgem method is a serious one:

- Capital and operating inputs are commonly substitutes in production processes. Thus, greater (lesser) utilization of capital will commonly make possible lower (higher) utilization of operating inputs. Ofgem's careful treatment of non-operational capex is an indication of its appreciation for this general problem.
- The utilization of capital by distributors can vary substantially for two reasons. Some companies try harder than others to economise on the use of capital. Additionally, capital spending is a somewhat cyclical phenomenon, and some distributors will, at a given point in time, have older systems using less capital – but requiring more opex for maintenance - than other distributors.
- Total cost benchmarking has been used in several U.S. and Australian regulatory proceedings. Studies have found that there is a significant positive correlation between the total cost performance of distributors and the age of their systems. For example, top total cost performances often have highly depreciated plant.
- It follows that the exclusion of a capital quantity index from a short run cost function can introduce serious omitted variable bias into parameter estimates and model predictions.

Ofgem apparently undertook some regressions using total cost as the dependent variable and found that efficiency scores are sensitive to the manner in which capital

cost is measured. It notes in this regard that “This suggests that these measures are not necessarily a good indication of operating cost efficiency.” The following remarks merit consideration in a response to this curious statement.

- Total cost efficiency appraisals are not designed to appraise efficiency in the use of operating inputs. If Ofgem is intent on measuring opex efficiency, it must nonetheless address the challenge of the correct specification of an output quantity index.
- Whether the issue is the specification of an output quantity index or capital cost, it may be true that results are sensitive to the capital measurement method. Capital measurement is nonetheless an unavoidable part of the challenge of accurate cost benchmarking. If Ofgem cannot settle on a satisfactory capital cost treatment and instead elects to ignore capital considerations, it is consciously choosing a biased benchmarking method.

In para 6.49, Ofgem reports the results of including average capex over the last ten years, whilst noting that it has no strong theoretical foundation. Ofgem does not however show the results of other, more plausible definitions of the capital stock, such as the one EDF Energy/NERA have prepared (acquisition cost inflated at RPI), which comes closest to an economic definition. In any case, the use of a ten year average cannot possibly capture the effects of capex/opex trade-offs decision taken over many years, or even decades.

In the context of dismissing total cost analysis, Ofgem notes that historically low capex might lead to some reward in the opex analysis and a “double-counting” if the same company was predicting high capex in the future (para 6.48). This statement seems to have lost touch with any semblance of logic. First, the point of total cost analysis would be to set total cost targets, so there would be no question of benefiting from “opex analysis”. Second, Ofgem does not consider using any standard definition of capital costs both to normalise accounts and to provide a basis for future time trends in total costs. Third, Ofgem overlooks the possibility that its opex-only analysis suffers from the exact same bias in reverse – namely that companies with high capex in the past will benefit from opex analysis in the future and may also be able to underspend future capex allowances.

Ofgem’s rejection of the total cost approach leads it to rely on separate analyses of opex and capex and hence creates a problem of double jeopardy for companies (like SPN) which have efficiently substituted opex for capex in the past, but which now require an increase in capex to sustain an acceptable quality of network service:

- The resulting “high” opex levels will be benchmarked against companies who favour capex and the inevitable difference will be assumed to be “inefficient”
- Any future capex increase will be compared to low historical levels and low rates of increase by other companies and are likely to be disallowed, as in the approach Ofgem/PB Power has taken.

Such an approach is discriminatory and is not consistent with Ofgem’s duty to ensure that efficient companies can finance their activities. It remains completely perverse that

the companies with the lowest total costs (and tariffs) can be regarded as amongst the least efficient on an opex only basis. In particular, competitive markets would not make such a distinction. Ofgem must address the issue of past capital substitution properly using the approach already recommended by EDF Energy/NERA.

Tree cutting costs

We believe that the tree cutting analysis carried out by Ofgem can be improved. In particular, and for no apparent reason, SPN has been significantly disadvantaged by the approach taken. Ofgem has not yet shared their detailed modelling of tree cutting costs with us. This would be a useful step in reaching an agreed position and we would ask that this is done at the earliest opportunity.

The output of Ofgem's regression analysis shows that SPN has been allowed £3.1m per annum for tree cutting. However, SPN's current tree cutting contract, which was competitively tendered, equates to an annual spend of £4.1m per annum in direct cost terms alone.

The regression analysis takes no account of the percentage of network subject to trees. Given that tree density and land use vary considerably across the country (both of which will impact on the level of tree cutting that a company must undertake) it is simplistic to assume that the CSV, even if it is weighted towards line length, is a suitable proxy for tree cutting cost drivers. Such simplistic top-down analysis is simply inadequate for setting cost allowances, unless it is supplemented by close scrutiny of the actual working conditions and practices of individual DNOs.

Ofgem's check analysis utilises average contract rates for tree cutting. However, this is likely to understate the costs in SPN given the fact that wage costs in the South East, and to a lesser extent in the East of England, are higher than the national average (see above for our comments on regional costs). It should also be noted that in 1997/98 PKF's view was that Seeboard should be allowed £4.2m (97/98 prices) for tree cutting¹⁵.

Achieving the benchmark and glidepaths

Ofgem states that "A reasonable approach would be to use the upper quartile as a benchmark", without offering any explanation as to why it is reasonable, even though it is unprecedented as a regulatory technique. Ofgem should explain its reasoning.

For the first time, Ofgem has proposed using benchmarking to set the opening level of allowed costs, rather than some target for future costs. This approach explicitly disallows costs on the basis of the information from benchmarking. This information is not robust enough to justify such a decision, because:

- The information has not been fully normalised and results will therefore be biased by downward errors in any one DNO's costs;
- The benchmarking applies only to a subset of costs (opex including faults), which overlooks the possibility of substitution between capex and opex (not only in

¹⁵ Para 2.29 PKF report June report on SEEBOARD costs and efficiency

accounting terms, but also in real decisions), and leads to a downward bias in the target for companies that have chosen opex over capex;

- The composite size variable recognises only a small subset of possible explanatory factors, such that Ofgem cannot possibly conclude that any unexplained or residual costs are due to inefficiency and should therefore be disallowed; and
- In particular, Ofgem has made no proper adjustment for regional costs.

Ofgem has chosen to impose an additional reduction in costs at 2% per annum, by reference to CEPA's report. Since that report gave figures around 2% per annum as the medium to long-term rate of efficiency improvement, Ofgem is proposing to disallow costs at a faster rate than the long-term rate of efficiency growth (which comprises both frontier shift and catch-up) without justification. Put another way, the rate of TFP improvement is an average – but Ofgem is not proposing cost targets based on average costs but is using an upper quartile level. Therefore, a 2% improvement rate will “occupy” the same cost zone between average costs and upper quartile and will thus be double counting efficiency improvements. Ofgem's proposals are therefore flawed in logic.

We also believe that Ofgem has taken the proposals of the lower cost companies out of context and that future rates of productivity improvements proposed by these companies were set in the context of rising input prices – which appear to have been ignored by Ofgem.

Ofgem has also asserted that the DNOs can achieve cost reductions without making any allowance for the costs of achieving them, which in effect amounts to a disallowance of costs. Ofgem needs to justify its stance.

Para 6.56 summarises all of the unjustified judgments inherent in Ofgem's conclusions, by arguing against a glide-path as if there were incontrovertible evidence of inefficiency, such that offering additional revenue would offer perverse incentives. This conclusion is not supported by the evidence available to Ofgem and the decision to disallow costs from 2005 is inconsistent with good regulation and, mostly likely, with Ofgem's statutory obligations to allow licensees to finance their licensed activities.

We note that Ofwat's recent initial proposals¹⁶ for water and sewerage companies propose a catch-up factor of 60% to frontier performance by 2009-10 together with a 0.3% annual productivity improvement. The drivers behind the clear differences in severity of targets between Ofwat and Ofgem need to be explained.

Ernst and Young report

We have previously written to Ofgem highlighting that there are internal inconsistencies with detailed data in the Ernst and Young report and their final conclusion with respect to EDF Energy. We are particularly concerned that Ernst and Young have stated efficiency savings for particular functions without specifying how these savings have been derived and which aspect of that function is inefficient. Consequently, we do not

¹⁶ Ofwat 2004

agree with the conclusions of the report and hence do not believe that it supports Ofgem's top down analysis. In addition, due to data issues the Ernst and Young analysis has been carried out only at the group level. The only comparison of results that could be made is between the Ernst and Young findings and the Group regression analysis. Compared to the baseline regression, the position of a number of companies changes significantly under the group analysis with respect to the benchmark costs. Therefore, we fail to see how Ofgem can assert that it supports its top down benchmarking

Unlike the top down analysis, the Ernst and Young work at least recognises that there are still issues which have not been resolved which impacts on the weight that should be placed on their conclusions e.g. capitalisation issues and regional cost differences. These issues also exist in the top down analysis, however, Ofgem appear to have ignored them.

Capital expenditure

Review of future capex

Overall, we do not regard PB Power's views of capex plans as sufficiently robust to permit Ofgem to be able to demonstrate that it has protected the interests of consumers. Similarly, we do not regard PB Power's view of the amount of capex required for our three DNOs as being consistent with our general duty to develop and maintain efficient, co-ordinated and economical systems of electricity distribution. It follows also that we do not regard PB Power's views as a robust basis for Ofgem's proposed sliding scale mechanism. These very strong concerns are based on the following important defects identified in PB Power's work:

- PB Power makes sweeping assertions throughout their reports to the effect that our proposals are not well defined, are insufficient, or are unjustified despite EDF Energy providing the relevant evidence. We are left with the clear impression that the reports are a rationalisation of a predetermined policy to reduce capex increases to levels similar to those proposed by other companies irrespective of the real condition of our network, or our customers' particular needs. Ofgem needs to clearly explain why the capex levels of other companies are relevant to the protection of our consumers' interests.
- PB Power's non load related (NLRE) and load related (LRE) models are simplistic and as such should only be used as a guide rather than an absolute measure (as Ofgem has done) of investment needs. In particular, their models fail to capture significant areas of investment. For example, the LRE model does not capture:
 - The impact of redevelopment areas such as Thames Gateway (up to 830MW);
 - Work associated with the Sellindge DC link to France;
 - Network Rail power upgrades; and
 - Summer peaking loads in London.

Ofgem should explain how it is in consumers' interests to exclude such investments despite the clear and obvious need.

- PB Power have proposed cuts to our allowed capex levels in areas where the investment is irrefutably necessary – such as the LPN's interconnected network – simply because we have presented it as a 'provision' – or because 'alternative options' have not been considered. The fact that implementation choices remain does not obviate the original requirement for *some* expenditure. It is unreasonable and inefficient to demand detailed plans for every expenditure identified at this stage, particular for investments required in 4-5 years' time.
- The process is asymmetric in that a DNO's submission can only be adjusted downwards, but not upwards. Since companies base case capex submissions were intended to hold risk to current levels, it follows that an asymmetric process must increase risk. Ofgem needs to clearly explain why such a policy is consistent with protecting consumers' interests.

- In SPN's case, PB Power indicated a higher level of spend than SPN had proposed. Yet instead of perhaps limiting the allowance to SPN's proposed spend, the allowance was set even lower, and was based on prior period spending levels.

Where PB Power's model is contradicted by the DNO submitting lower forecasts, Ofgem and PB Power happily abandon the model's forecast. If the model is wrong for some DNOs, it must be considered wrong for all of them. Yet when (inevitably) some DNOs submit a higher figure than PB Power's model suggests, Ofgem relies on PB Power's figures. Ofgem's assessment of capex needs therefore treats DNOs differently, without objective justification.

PB Power's capex assessment

We have provided detailed observations regarding Ofgem's initial assessment of future capex levels under cover of our letter dated 30 July 2004 to Ofgem. In particular, we have provided extensive commentary regarding PB Power's modelling and benchmarking approach. For the sake of brevity, our comments below include only a summarised version of our previous comments in this respect.

We welcome Ofgem's and PB Power's openness in sharing with us the workings of the NLRE and LRE models used to form the foundation of PB Power's analysis and Ofgem's Initial Proposals. Having observed the methodologies underpinning these models, our view is that these are at best a useful 'sense check'. However, the PB Power 'opinion' appears to be predominantly biased towards the model (or benchmarked) output and heavily disinclined towards the evidence provided by EDF Energy in support of our LRE and NLRE submissions.

In disclosing our Network Asset Management Plans we believe that we have provided sufficient evidence, in support of our completed FBPQs, to justify our future capex proposals. In addition, we have always been very willing to share with PB Power any additional evidence that they have requested. We are therefore disappointed by the very arbitrary nature of the overall process that has led Ofgem to propose significantly lower levels of allowed capex.

A general feature of PB Power's modelling and benchmarking methodology is that it is asymmetric in terms of adjustments to companies' submissions. In other words, companies' submissions can be adjusted downwards, but not upwards. It follows that the resulting overall risk position will be greater than that which companies, as a whole, deem appropriate. Moreover, since the Base Case submission is essentially concerned with maintaining risk at the current level, it follows that risk as viewed by companies as a whole must be increasing. This approach might have merit in benchmarking companies' 'quality' or 'preferred' (DNO) scenarios – but not their 'constant risk' Base Case scenarios.

It is disconcerting that even where the benchmarked output suggests a given level of capex, the PB Power approach is often to make yet further arbitrary cuts. We see no justification for PB Power to suggest that any company should receive a lower allowance than the benchmark unless that company is itself proposing (and indeed justifying) a lower level of expenditure.

Appropriateness of risk

Apparently underpinning PB Power's approach is their statement that 'the level of network risk experienced during DPCR3 should also be held constant during the forthcoming review period'. Whilst this may have been the intent behind the Base Case submission, it is by no means the correct basis on which to assess a company's allowed capex. Excellence in Asset Management involves a continuous review of the appropriateness of any given level of risk. There are many examples, some backed by new legislation, which illustrate that maintaining a 'constant' level of risk is not necessarily appropriate. By way of illustration:

- The ESQC Regulations have forced a review of measures necessary to manage public safety risk that will undoubtedly lead to higher levels of NLR expenditure once the impact assessment work is complete. The current wide variation between companies in terms of expenditure attributed to ESQCR will no doubt be addressed during companies' further discussions with Ofgem and the DTI;
- The concept of 'Corporate Manslaughter' which has already given rise to prosecutions of Directors and Senior Managers in other industries provides a clear message that the wider aspects of management of public safety risk must now be much higher on every infrastructure management company's agenda;
- Customer reaction to the extensive supply failures following the October 2002 storms (compared to the reaction following the 1987 hurricane) clearly shows that tolerance levels to 'long' supply interruptions have changed markedly;
- The impact of the major power failure in London (and other major cities) in 2003, and the subsequent investigation by the DTI, provides a clear indication that ensuring supply security in important commercial centres must now be regarded as a much higher priority;
- The recent growth in summer loading due to air cooling has created a need to review our criteria for assessing P2/5 security risk, especially in central London;
- The Groundwater Regulations 1998 and our own recent 'near misses' with regard to major leakages from oil-filled cables (and subsequent interviews, held under caution, by the Environment Agency) make it clear that control of pollution risk with regard to water courses must now be given a greater level of priority in our overall asset risk management (and investment) strategy.

Adopting a 'head-in-the-sand' stance to new legislation, and to these very clear indicators of changing risks and/or perceptions as to what constitutes 'acceptable' levels of risk, would be irresponsible, and certainly not in the best interests of our customers. Our DNO Case submission includes measures specifically directed towards maintaining 'appropriate', rather than 'constant', levels of risk.

Trade and Industry Select Committee Report

We would draw Ofgem's attention to the Trade and Industry Select Committee's report – March 2004 - concerning the 'Resilience of the National Electricity Network' which advocates the need for a change in focus towards long-term resilience. As an example, we would cite the statement in the Summary to the report that 'the Regulator's concern to reduce costs to consumers should now be tempered by a greater emphasis on ensuring that electricity network owners have the financial resources necessary to secure a viable long-term electricity supply'. We agree entirely with that view, and it is

with this specific objective in mind that our DNO submissions have been prepared. We do not believe that PB Power's modelling, or Ofgem's Initial Proposals, in respect of allowed capital expenditure adequately reflects this important objective.

In view of the above, our DNO Case FBPQ submission for EPN, LPN, and SPN should be the basis of determining allowed capex levels.

Non load-related capex

Overall we believe that the NLRE model is useful as a sense check, but there are serious anomalies and omissions that would need to be addressed before the model could be considered sufficiently robust to determine appropriate levels of NLR expenditure. In summary, the areas that need to be addressed are:

- Further studies need to be undertaken to assess the sensitivity of outputs to assumptions over assigned life, and recognition given to the fact that a company's condition information must take precedence in assessment of achievable life;
- Given that, in most cases, PB Power's unit costs are generally in the same 'ball-park' as EDF Energy's, this suggests that where PB Power's costs are significantly lower, this must be due to different assumptions over achievable solutions – or due to omissions in PB Power's make up of those unit costs. These anomalies clearly need to be investigated;
- Account needs to be taken of the categories of asset replacement that the NLRE model has not captured. Simply multiplying FBPQ volumes by unit-costs does not capture the whole of the NLRE required expenditure. It follows that the MEA values calculated by PB Power as a sense check for both the NLRE and LRE models will be understated.
- It is not apparent that costs associated with operational property civil works and protection replacement have been adequately considered in PB Power's analysis. These are important and significant aspects of our submission.
- Further consideration needs to be given to regional (south-east) cost factors and their impact on unit costs, and especially to LPN-specific costs where a higher unit cost (i.e. higher than EPN and SPN) has not so far been assumed.

Oil-filled cables

We acknowledge Ofgem's current engagement with ourselves in meaningful discussions regarding a proposed long-term programme of replacement of oil-filled cables. We also acknowledge Ofgem's helpful decision to remove oil-filled cable expenditure from the initial NLRE analysis pending further consultation. We will work closely with Ofgem to develop a regulatory and financial framework that will allow EDF Energy and other DNOs to undertake removals or replacements of oil-filled cables at a rate that is commensurate with the environmental and operational risk that the degrading condition of these assets presents.

ESQCR investment

We welcome Ofgem's approach with regard to ESQCR-driven capex (and opex). This is an important area of expenditure because it is directly associated with managing public safety risk. It is however evident from Ofgem's table A9 that companies have initially adopted very differing positions with regard to ESQCR related expenditure. We

are sure that part of this difference will be due to interpretation of what should be specifically allocated to 'ESQCR' rather than due to fundamentally differing views on the measures necessary. It will be important to ensure that the industry, Ofgem, and the DTI reach a common agreement as to the levels of capex (and opex) necessary to effect such measures within a reasonable timescale.

Overhead line network resilience

We strongly disagree that the case for 'network resilience' has not yet been justified. Such a position flies in the face of the DTI / Ofgem / Energywatch / DNO joint 'Network Resilience Working Group's' recommendations (as reported in December 2003) following the severe storms of October 2002. Moreover, we believe that Ofgem are wrong to regard this as a 'customer willingness to pay' issue. First and foremost we believe that overhead line resilience to severe storms is primarily a public safety issue. Improved quality of supply performance will be a secondary effect that will be significant only in terms of reducing annual performance volatility and susceptibility of the network to extensive damage during severe weather. The proposed expenditure, if properly targeted, will provide value for money to consumers, partly by reducing the likelihood of prolonged supply interruptions, but mainly by greatly reducing their risk of contact with falling (or fallen) conductors (possibly live) and other overhead line apparatus during severe weather.

Replacement of bare and small cross-section conductors

We would draw Ofgem's attention to other key external reports that support our view regarding overhead line resilience measures. Firstly, we would again cite the Trade and Industry Select Committee's report concerning the 'Resilience of the National Electricity Network' – for example section 5 paragraph 84 which advocates as prudent the 'building of some extra resilience into the system'. More specifically, however, we would cite the report by The Engineering Inspectorate DTI – 'Research and Analysis of a Possible Safety Improvement Involving the Selective Replacement of 11kV/LV Bare-Wire Overhead Lines with Ones Having Covered/Insulated Conductors'. In the introduction to the report, it is noted that Ofgem had commented that 'if a DNO was to present a sound business case for such investment as part of their overall investment plans, it would be taken into account in setting their new price control' and that 'in order to do that, the DNO would have to demonstrate adequate payback in safety'. We note Ofgem's implied acknowledgement that 'safety' rather than 'quality of supply' is the key criterion.

The thrust of our proposed LV Overhead Line capital expenditure programme is around selective replacement of bare conductors. We are aware of instances where live bare conductors have come into contact with (or have come close to) the ground during severe weather conditions so as to present a severe public safety risk. Our assessment is that whilst increased focus on tree cutting will help reduce the risk of breakages to conductors or supports during severe weather, in many cases, the risk will not be adequately mitigated other than by use of covered conductor (or undergrounding).

Whilst not a specific recommendation of the above-mentioned report, we also believe that the selective replacement of small cross-section 11kV conductors is an essential additional measure to properly address the risk of conductor breakages during severe weather – especially where there is a risk of ice accretion.

Supporting meteorological evidence

Finally, we would cite the Meteorological Office's report - August 2003 - 'Extreme Weather events Likely to Cause Disruption to Electricity Distribution'. The report notes in its conclusions that 'the region where (tree) growing seasons may extend furthest, i.e. southern England, is also the region predicted to see the greatest increase in both wintertime mean wind speeds and the frequency of occurrence of strong winds as climate changes'. The report also notes that 'the intensity of lightning storms may increase in the south of Britain in the future'. And, whilst the report is inconclusive as to likely future trends in ice accretion risk, it does note that 'it is likely that work to improve resilience of the network in the Birmingham area' would be justified due to the frequency of freezing rain events. An arc centred on Birmingham of just 60 miles radius would sweep across some 80 miles of EPN's western, largely rural, area.

Load-related capex

PB Power stated during our meeting in Newcastle on 21st May 2004 that they had more confidence in their LRE model. Whilst we have some serious reservations regarding the simplifying assumptions within the model, we could at least see some level of agreement between our submission and the initial output of the model for both LPN and SPN that was shared with us prior to that meeting.

It is therefore both surprising and disappointing to note that arbitrary and unsubstantiated cuts have subsequently been made to both the LPN and SPN model outputs. At no time since our meeting in Newcastle have we been given any indication that PB Power had any issue with the validity of the LRE model outputs, or that such adjustments were being considered. Neither have we been asked to supply any further information to support those areas of the submission that PB Power appear to now regard as unjustified or inappropriate.

An important (but unacknowledged) limitation of the LRE model is that, by its very nature, it will not identify legitimate 'load-related' reinforcement driven by legacy network design issues, unusual patterns of load growth (such as summer air cooling) which require very different considerations of equipment ratings, external factors such as the operation of the NGT system, or fault level issues. Neither will the model capture the 'up-front' costs associated with large scale developments such as Thames Gateway.

In this latter context, it is relevant to note that whilst the model output generates gross capex numbers, we would also comment that LRE net capex requirements are particularly sensitive to large scale developments given the anticipated effects of the proposed Structure of Distribution Charges. We are not yet confident that the effects of the proposed Structure of Distribution Charges have been fully understood, particularly for a region that expects substantial major redevelopment over the DPCR4 period. Neither is it apparent that the logical effect on Customer Contribution figures of PB Power's proposed cuts in gross LRE capex has been properly considered.

Areas for special consideration

All three of our networks contain examples of reinforcement drivers that we would suggest are 'out of scope' in terms of the PB Power model's consideration of LRE, and these have a very significant input to our overall requirements for LRE capex. These examples include:

- The Thames Gateway regeneration project which is unprecedented in Europe in terms of scale of brown-field redevelopment. This impacts all three networks at different time periods, but has a significant impact on both LPN and EPN during the DPCR4 period. We have been provided with indicative demands ranging from 190 to 830MW over the period to 2016. Other very significant redevelopment areas include Paddington, Kings Cross, Docklands, Milton Keynes, Stansted / M11 Corridor, Ashford, Hastings, the Medway region, Isle of Thanet, Croydon, Gatwick, Cambridge, Norwich, Lea Valley and the proposed London Olympic Village, and CTRL phase 2 related development.
- For SPN, the operation of the (NGT) Sellindge DC link has prompted the need for substantial network reinforcement that is quite unrelated to load-growth per se. The relevant schemes have been clearly highlighted and should effectively be regarded as supplementary expenditure that is outside the scope of PB Power's LRE model. This is a uniquely 'SPN' investment driver, but an essential aspect of our reinforcement proposals. We appreciate that PB Power may not have yet fully understood the complex issues involved. Some £15m of LRE has been earmarked for DPCR4 to address the problems directly associated with the Sellindge DC link.
- For SPN, the Network Rail upgrade project is currently the subject of some very close liaison between EDF Energy and Network Rail aimed at maximising utilisation of current network capacity and minimising reinforcement need. This is supported by a regime of on-line monitoring of demand and power quality. As yet, it is uncertain as to the extent to which the network will need to be further reinforced once the new trains are fully operational. It is relevant to note however, that we have already had to make an application for derogation in respect of G5/4 due to harmonic resonance issues. Compliance with P28 is a further area of study that may lead to further reinforcement need.
- For EPN, a number of schemes have been identified to deal with unacceptable legacy issues surrounding the West Suffolk / North Norfolk interconnected 33kV system. Whilst these issues are ultimately related to load growth, the required approach is not generally a matter of effecting simple increases in transformer capacity, but of substantial network reinforcement and reconfiguration. These complex 33kV networks are designed to be self-supporting, but continued load growth has stretched their capacity to remain P2/5 (and voltage) compliant during single circuit outage conditions to the extent that action is now required.
- Some £17m (£27m in our DNO Case) of LRE has been earmarked for DPCR4 to finance a number of essential substation, overhead line, and cable reinforcement schemes to address the problems directly associated with the West Suffolk / North Norfolk interconnected 33kV system. We have also identified since our submission the need for a further £10m of major reinforcement associated with a new connection project at Norwich, but which provides essential upstream reinforcement to the 33kV ring to enable the connection to proceed.
- For LPN, growth in summer loading has resulted in the need for a new approach to determining firm capacity. Peak loads coinciding with average daytime ambient temperatures of over 30° C such as were experienced in August 2003 (rising to 36° C average daytime ambient on 6th August) require a different assessment of emergency plant ratings, and hence the triggers for reinforcement. Some £28m of essential Main Substation reinforcement has been included in our submission specifically to deal with summertime capacity constraints.

- For LPN, the legacy issues concerning the Central High Load-Density Zone LV interconnected HV network are now in urgent need of resolution. The continuous load growth that we are experiencing in this part of London is leading to major operational issues, not least of which is frequent cascade fuse failure in the event of an HV fault. Solutions to deal with the issues are extremely complex, requiring both major network reconfiguration and selective automation – in addition to increased circuit capacity. Some £25m of LRE has been earmarked for DPCR4 to begin to address the problems in this part of the interconnected network.

BPI review

Because of the scale of the gap between our load-related capex submission and the output of the PB Power model, we have commissioned BPI to undertake an independent review of our Network Reinforcement proposals. A copy of the EPN report accompanied our earlier observations regarding the PB Power model. Whilst BPI have indeed identified possible savings that would justifiably reduce our LRE allowed capex below our EPN DNO submission, the savings are very much smaller than those suggested by PB Power's report.

Similar reports are in the course of preparation in respect of our LPN and SPN load-related capex submissions. We are prepared to fully accept BPI's findings which are based on a thorough analysis of each proposed major reinforcement project rather than a top-down modelling approach. We will share these additional reports with Ofgem as soon as they are available. We are confident that BPI's analysis would stand up to any future independent review.

Sliding scale mechanism

Ofgem intends to put in place a sliding scale incentive rate (23% for EDF Energy). It is our understanding that this would apply to both capex and opex on the grounds that robust cost allocation definitions are not in place and that Ofgem intends to equalise incentive rates. Under the sliding scale mechanism Ofgem would allow but not encourage overspends (expenditure in excess of the “allowance”).

This inclusion of opex raises a number of important concerns:

- the incentive rate for opex savings would be based on a company’s ability to predict PB Power’s capex estimate – which is irrational
- Sliding scale mechanisms imply a choice, yet no such choice regarding opex allowances is available;
- the recovery of opex overspends would need to be allowed (albeit net of the marginal incentive rate), i.e. customers would pay for potentially inefficient costs – which is irrational; and
- Efficient opex overspends would be penalised at the marginal incentive rate even though customers are not impacted¹⁷ - which is also irrational.

If it is Ofgem’s intention not to allow the recovery of opex overspends, (apart from where a limited scope re-opener mechanism applies) then it follows that the accounting definition of capex and opex remains important, since otherwise companies could reclassify opex overspends as capex and ensure at least partial cost recovery. It also follows that it is not possible to balance incentives between opex and capex simply by ignoring the definitional issues.

The treatment of capex overspends is also of concern. The sliding scale mechanism would penalise capex overspends at the marginal incentive rate (i.e. 23% - equivalent to reducing the marginal rate of return from 6.6% to 3.0%). However, Ofgem has already set out “eligibility tests” to address overspends in its March paper¹⁸:

- a. “Wasteful” capex would not be included in the RAV;
- b. Efficient overspends would be treated symmetrically with underspends; and
- c. Efficient spending with “significant benefits to consumers (e.g. being essential for security of supply)” would attract full regulatory return and depreciation.

Category c. covers the type of expenditure currently being rejected in PB Power’s estimate, which does not sit at all well with the sliding scale mechanism which would penalise such expenditure at the marginal incentive rate. Ofgem needs to provide clarity of the interaction of the sliding scale mechanism with the eligibility tests.

¹⁷ Ofgem might argue that overspend could impact their benchmarking analysis at the next review – however, use of a frontier approach would make this unlikely.

¹⁸ Para 3.67 March Policy Document

Both category b. and c. overspend and the associated acceptance by Ofgem of all or part of the relevant expenditure on to the RAV, give rise to an implicit acceptance by Ofgem that PB Power's estimate was inappropriate. In such a case the justification for different incentive rates between the companies is considerably weakened. Of course, this would not be an issue if DNOs were free to choose an incentive rate/capex allowance mix from the menu presented – however, it is not clear that such a choice is actually available. In any case, choice is not practicable until PB Power's work is completed and their estimates amended accordingly.

There are also perversities associated with the additional revenue allowance which is given to companies relative to their ability to predict PB Power's estimate. Ofgem has apparently designed the sliding scale to provide a profit incentive for DNOs to predict the same level of investment as PB Power. This is not a proper objective of regulation, since PB Power's forecast is not robust or accurate. Sliding scales or "menu" incentive schemes are intended to encourage regulated companies to declare information accurately. Ofgem's proposed approach would actually *penalise* a company that took accurately declared and carried out its intended capex, if its efficient level of capex were higher than PB Power's somewhat arbitrary estimate. This outcome cannot be consistent with Ofgem's statutory obligations.

We remain of the view that the sliding scale proposal cannot replace a properly considered capex forecast, and if Ofgem is concerned about gaming, it should place limits on the incentive rewards available.

External verification

As Ofgem is aware, EDF Energy is currently in the course of having its Load Related capex plans examined by expert consultants. It is our intention to adjust our forecasts to align our capex forecast with consultants' recommendations, whose report we will share with Ofgem. Work on Load Related Capex will be completed by around mid August. The work on Non-Load Related Capex is also planned and will follow. We would expect our resubmissions to be recognised appropriately with respect to Ofgem's proposed incentive schemes.

Financial issues

Cost of capital

We have submitted evidence from Oxera and NERA on CAPM and DGM approaches to assessing the cost of capital and we welcome Ofgem's consideration of the points raised as set out in the summary of responses to the March policy paper document. However, it is clear that the DNOs' position is still some way from Ofgem stance. As a result, we suggest that Ofgem includes an update to its thinking in the proposed September update document rather than waiting until the final proposals in November.

Ofgem estimates a post-tax cost of equity (CoE) of 7.25%. This is close to the upper end of the range in the April documents, which was 3.75%-7.5% (although the lower end of this range was never seriously in the picture). The upper end of the range was based on the following underlying parameters:

- Risk free rate 3.0%;
- ERP 4.5%;
- Equity beta 1.0; and
- Cost of Equity = $3.0 + 1.0 * 4.5\% = 7.5\%$.

Since the "new" Cost of Equity of 7.25% is only slightly less than the upper end of the range, we can assume that the "new" underlying parameters are also only slightly less than these parameters, although Ofgem does not quote them explicitly.

The beta of 1.0 was based on equity betas observed directly from stock market returns, and are only relevant to companies with the same gearing as the stock market overall. The average gearing of Ofgem's comparable companies was 38%, significantly below the 60% Ofgem is assuming in its calculations. Ofgem did not, as it should have done, de-lever the betas to find the implied asset betas, and then re-lever them for the appropriate gearing level, in this case 60%. As a result, Ofgem's estimate must be based on internally inconsistent data, and is contradicted by the internally consistent estimates provided by NERA for both CAPM and DGM.

Ofwat's draft determination of future price limits for water, published on 5 August 2004, shows that Ofwat has moved closer to the water industry's position on the appropriate assessment of the cost of capital.

Ofwat said at an early stage in its review that the evidence pointed to a basic cost of capital no lower than 5% post-tax in real terms. This compared with 4.75% (on a like for like basis) used at the previous review. The companies in their final business plans argued for a post-tax cost of capital ranging from 5% to 5.5% in real terms. Ofwat has now settled on 5.1% post-tax in real terms (which equates to 7.3% on a fully pre-tax basis, assuming a 30% marginal tax rate). This is in part because Ofwat accepts that the return required by equity investors has risen since the last review.

There are a number of significant inconsistencies between the bases for Ofwat's WACC decision and Ofgem's WACC decision. As examples:

- Ofwat's ERP range is 4.0%-5.0%; Ofgem's range is 2.5%-4.5%.

- Ofwat's range for the risk-free rate is 2.5%-3.0%; Ofgem's is 2.25%-3.00%.

Ofcom has recently set out their suggested WACC for the Partial Private Circuits Price Control. This WACC is based on an ERP of 5% which is also significantly different from Ofgem.

Ofwat's WACC estimate of 5.1% is also consistent with parameter estimates at the *upper* end of the their range whereas Ofgem's WACC estimate of 4.6% is consistent with *mid-point* estimates of their (lower) ranges. It would be most irregular to allow these inconsistencies to stand.

The comparison between water and electricity, therefore, now looks like this on a post-tax real-terms basis:

	Previous review	Present review
Electricity	4.5%	4.6%
Water	4.75%	5.1%

Tax

We are examining the tax computation in Ofgem's financial model which we have only recently received, and will write separately concerning any concerns/suggestions arising from this work.

Financing issues

Ofgem observes that its test ratios reveals SPN as the only company having a "major financing issue" in response to a low starting RAV and relatively increased projections of capital expenditure (based on PB Power's view of capex). Ofgem goes on to note correctly that the financial ratios would be worse if EDF Energy's own capex projections were used. Ofgem describes three approaches to resolving this issue:

- (a) Increase revenues;
- (b) Advance revenues; and
- (c) Increase equity.

Ofgem has not ruled out making adjustments, which we assume refer to techniques (a) or (b) above, but concludes that shareholders would provide additional equity rather than let credit quality deteriorate, "particularly if only a small number of companies are affected and there is not a general financial constraint across the sector".

SPN's low RAV has the effect of increasing its "operational gearing" in comparison to DNO's with relatively larger RAVs. In other words, SPN's relatively low RAV means that its proportion of fixed costs to revenue is greater than for other companies. Fixed costs are, by definition, unavoidable in the short/medium term and therefore have the same effect on risk as debt. The cost of such risk will, of course, manifest itself in the price demanded by equity/new equity, and we would therefore expect SPN to have a cost of capital higher than the sector level unless revenues were increased through other means (i.e. from customers).

We also believe that to be consistent with its general financing duty, Ofgem's approach to this issue should be:

- Non-discriminatory; and
- Be consistent over time.

Ofgem's current stance seems to pass neither test since its policy depends on there being no financial constraints (which is likely to be the case if many companies were seeking equity at the same time), and as investment levels are rising more companies are likely to be in this position post 2010 – inevitably requiring a change in policy.

Ofgem should put in place an enduring solution to this problem that should not discriminate between companies either now or through time, and which recognises operational gearing risks. This would suggest that at least a proportion of the additional funds required are met by customers (which is the approach Ofgem has taken in relation to the funding of Transco's ductile mains replacement programme).

Should new equity be a feature of the funding mix going forward then it would also be appropriate for Ofgem to allow appropriate cost recovery. We are pleased that Ofgem is considering making such an allowance.

Ofgem should model a range of scenarios to ensure that companies can finance their activities across a range of business conditions. In particular, the impact of major uncertainties (not covered by specific re-opener mechanisms) should be included, for example DG related expenditure/ revenue and unfunded pensions obligations.

Treatment of pension costs

Allocation between price controlled and non-price controlled activities

We have written to Ofgem¹⁹ regarding further detailed analysis we have been able to conduct on an employee-by-employee basis. This analysis substantially changes the allocation of liabilities between price-controlled and non-price-controlled activities for SPN and LPN (Ofgem correctly use an allocation of 100% DNO for EPN) on a pro-rata of employee numbers. We ask that Ofgem amends the allocations used to split liabilities to over 80% in line with the detailed evidence presented in our letter.

To date, Ofgem has split liabilities on a simple pro-rata of employee numbers. As we state in our July 28th letter, we have asked our actuaries to match each individual employee's liability to their price controlled/ non-price controlled service ratio for SPN (we hope to do the same for LPN). This will provide an accurate employee-by-employee analysis for Seeboard Group of ESPS fund deficit and its attribution to price controlled and non-price controlled activities. We will inform Ofgem in due course when this information becomes available.

For scheme members who left prior to privatisation, we continue to seek clarification from Ofgem on how it proposes to split liabilities in the year of privatisation. The Initial Proposals are silent on this issue. The prospectus document does not contain the necessary split of employment cost information.

¹⁹ Letter to Samuel Kwafo (cc. Carl Hetherington), dated 28th July 2004 "Updates to allocation of price controlled and non-price controlled headcounts for splitting liabilities in SPN and LPN".

We are also investigating a legal issue relating to SPN's Utilities Act 2000 transfer scheme and will discuss this with Ofgem when more information becomes available.

Under or over provision

It is not surprising to us that the treatment of ERDCs is the main issue being raised by DNOs. We welcome Ofgem's acknowledgement that the treatment of ERDCs was not clear in previous price controls and that it was efficient for companies not to make contributions to the scheme that were not needed at the time. EDF Energy are still of the view that the only objective and sound regulatory assumption that Ofgem can make is that previous price controls made allowance for all the contributions actually made. We disagree that there is any merit to Ofgem's arguments set out in the March 2004 consultation document. Our response to the March document on the treatment of ERDCs remains our position – namely that all past uses of surpluses should be allowed.

Leaving aside this fundamental argument, we also have comments on Ofgem's logic for determining the disallowance of 30% of the ERDC deficit. Ofgem appear to conclude that DNOs, on average, obtained 30% of the benefit of an ongoing opex saving. This is presumably based on companies achieving a saving for five years before it is taken away in the next price control period. We consider this number (30%) to be flawed because:

- Using Ofgem's own numbers²⁰, the value of an opex saving kept for five years by the company represents 29% of the value of the saving in perpetuity, equivalent to Ofgem's 30%. This assumes that the company has the full saving from the very start of the five year price control period;
- Based on NGC's numbers, the average use of surplus occurred when there were three years of a price control left - although NGC tended to have four year price control periods (as opposed to the DNOs five year periods). It must be true for the DNOs therefore that they did not, on average, obtain five years' worth of benefit from use of surplus.

If you assume that use of surplus occurred evenly throughout a five year period, the company would only have enjoyed 18% of the gain, the balance going to customers. We recognise that use of surplus probably is weighted towards the front end of a price control period but consider that 30% must be significantly higher than the actual benefit received. Only Ofgem has the data to quantify how many years benefit the companies received from the use of surplus. We request that Ofgem conducts further analysis on this point.

Finally, it should be noted that changes to the price controlled and non-price controlled allocations (described earlier) will impact the allocation of ERDCs (notwithstanding all our arguments above about full allowance). In the Initial Proposals Ofgem uses an incorrect ERDC amount for SPN (£46.4m). Based on the information sent to Ofgem (in the Pensions Contributions Information Request) £40.6m should have been used. This has somewhat been overtaken by events and Ofgem's additional request for information (received 28th July 2004). We do however request that Ofgem quality

²⁰ Page 25 of May 2003 Network Monopoly Price Controls.

assures its calculations prior to publication of the September document so that these types of errors do not recur.

Calculation of pension allowances

We addressed this topic in our 28th July letter to Ofgem. For clarity, the main points are repeated below, with some additional commentary.

Ofgem have previously indicated their intention that the pension allowances included in the final price control proposals will reflect the actual contribution rates paid to ESPS pension funds – to be determined by the autumn Triennial Valuation. These actuarially determined contributions rates will include appropriate amounts to eliminate accumulated fund deficits over the course of the remaining Average Service Life of each fund. We support this approach.

In the Initial Proposals, Ofgem had to make assumptions ahead of the Triennial Valuations to determine draft cost allowances. One assumption was for 13 years to be “the generally accepted estimate of average remaining service lives” and simply divided the estimated pension deficit by 13. In reality, if the deficit is not immediately fully funded by cash contributions, the effect of discounting to cover deferred payments will require larger ongoing annual contributions. These larger contribution rates will be reflected in the actuarial valuations and must be included in the allowances given by Ofgem.

We should also point out that the Seeboard ESPS scheme has an average remaining service life of just ten years. The use of 13 years in the Initial Proposals considerably understates the level of cost that will be incurred and we request that Ofgem amends its calculation to reflect the reality in SPN’s case.

We would also like to point out that should the company and trustees not agree on a recovery period the scheme actuaries may decide that the company’s stance is not reasonable. In such cases Ofgem must take account of the actuary’s “ruling”.

Since EDF Energy’s FBPQ submission, our actuaries have indicated to us that we should also anticipate increases to normal pension contribution rates for current employees that will be effective from 1st April 2005. These new contribution rates will, of course, be determined by the autumn Triennial Valuation.

We ask that Ofgem confirms, ahead of the September document, that they will give full allowance in the price controls for the cash contribution rates determined by the autumn Triennial Valuations of the ESPS funds.

Setting price controls

The Balance Between P0 and Xd

A reasonable positioning of Xd would be for this to recognise the expected level of operating cost efficiencies behind the operating cost allowance within the price control.

In this case, the reduction in annual revenues is consistent with the cost efficiencies, avoiding a confusing growth or decline in year-on-year reported profits.

However, Ofgem have proposed an Xd of 1% which is inconsistent with the 2% annual efficiency factor imposed on operating costs. This will create an artificial increase in reported profits as costs decline faster than revenues. Ofgem should ensure that the Xd factor is consistent with underlying operating cost efficiencies.

Distributed generation, innovation funding incentive and registered power zones Regulatory Instructions and Guidance

We continue to be very concerned by the requirement in paragraph 2.23 that we should provide information about operations and maintenance costs for a particular (and quite complex) subset of the distribution network. Existing management and financial systems - and the associated business processes – have not been set up in this way. They do not link costs with a particular, geographically defined, physical part of the network. Thus it would be time consuming, complicated and expensive – from the point of view of both system development costs and on-going operational costs - to do this for networks as complex as that of a DNOs (and which is constantly being reinforced, replaced and extended). We therefore believe that this section should be deleted from the RIGs and any information requirements that Ofgem may have in this area be approached in a more cost effective manner.

We have a number of detailed points on the Regulatory Instructions and Guidance (RIGs) and these are provided below

1. Paragraph 2.3 refers to “relevant agents”. In the interests of clarity it may be worthwhile defining this term.
2. It could also be useful to define the “reporting year”.
3. Paragraph 3.11 states that “eligible IFI projects will be justified...on the expectation that the Present Value of its costs will be exceeded by the Present Value of its benefits...”

In our response to “Electricity Distribution Price Control Review Appendix - Further details on the incentive schemes for distributed generation, innovation funding and registered power zones” (see below) we argued that there was a need in assessing projects to recognise that such present value benefits may best be expressed as ranges, and that some projects will be enabling. Ofgem has also recognised that some projects - for example those whose benefits are safety related – are not easily assessed on a net present value basis. In view of the legal nature of the RIG we feel that these factors should be recognised in the drafting of paragraph 3.11.

4. The RPZ application procedure has now been outlined and we feel that in the interests of clarity and certainty this should be included in the RIG.

Further details on the incentive schemes for distributed generation, innovation funding and registered power zones

Distributed Generation (DG) Incentive

We have consistently supported the need for an appropriate mechanism to incentivise distributors in relation to the connection and operation of DG in previous consultation responses and continue to do so. We therefore welcome Ofgem's continuing commitment to such an approach and the increasing clarity of the details of the scheme. Whilst we recognise the statement covering the risk-reward balance in the appendix providing further guidance on the scheme, we are disappointed that it may not sufficiently encourage distribution network operators to invest in their networks to further prepare them for significant DG connections in view of the serious and profound issues that climate change raises. Nevertheless we intend to fully utilise the benefits of the scheme where it is possible to do so.

In our previous response we argued for the inclusion of micro-generation within the incentive scheme so we welcome the decision to so include it.

We are surprised by the treatment given to high-cost projects in the draft licence condition. Our view is that this feature should be a safeguard for DNOs against the emergence of projects with very low rates of return. However the approach used in the algebra of the draft licence condition means that it is, in fact, no more than a funding mechanism which spreads the high cost of the project over 15 years. This is a significant dilution of what we believed the original intent of the safeguard to be and should be rectified such that the benefit of connection charges in excess of £200 per kilowatt of DG is retained by the DNO.

We are also somewhat concerned with the late insertion of the additional project size test of £100,000 before a project can be treated as high cost. This is exacerbated by a lack of clarity of whether this applies to total project cost (i.e. including sole user costs) or to shared costs or a proportion of them. We again feel that this may be a significant dilution of this protection and whilst we will undertake further analysis once the precise definition of the test is confirmed, our preference would be for the £100,000 test to be withdrawn.

We are disappointed that there will be no explicit regulatory treatment of ancillary service costs. As the penetration of distributed generation increases, opportunities can be expected to arise where network benefits can be obtained from making use of such generation. Ofgem suggests that the DNO will benefit to the extent that ancillary service costs are less than opex or capex savings. However we feel that the impacts may be somewhat more complex than that and will interact with the incentive arrangements that are finally agreed covering both opex and capex. There is a danger that may be a continuing regulatory barrier to the development and application of ancillary services in circumstances which are appropriate and beneficial to DNOs, generators and customers generally. Suggestions for possible mitigations to this issue include a commitment from Ofgem that any expenditure on ancillary services would not be taken account of in assessing future DNO relative efficiency, and that incentive regimes should be structured such that such ancillary service expenditure should not be penalised.

Ofgem has indicated in paragraph 1.24 that they will be asking DNOs to update their forecast of cost re-allocation as a result of the “shallowish” (rather than “shallow” connection charge boundary). This will presumably also provide an opportunity to update the forecasts of DG capacity connected for the 2005-10 period and the associated costs which were derived around a year ago at the time of the preparation of the distributed generation business plan questionnaires. Further information about the amount of data that will be requested and relevant timescales would be welcome.

We continue to believe that the ongoing incentive for network access is premature, inappropriate and insufficiently thought through. The information necessary to apply the proposals is likely to be difficult and expensive to collect and the application of the proposals themselves will be complex and cause disproportionate dispute. For example, we see the assessment of baseline network interruption duration which we assume – although it is not explained – relates to the “strength” of the network connection as likely to be troublesome with the potential need for ongoing regulatory involvement. Other issues include the incorporation of the implications of this part of the scheme into generator use of system charges where different approaches may well be necessary for small, medium and large sized customers. At this stage it seems far more appropriate to apply a guaranteed service standards type approach – as is the case for demand customers – to new generator connections. In addition, we confirm our view that the failure to provide a cost recovery or incentive mechanism for the schemes costs and the failure to provide for the prospect of some upside that this will be a systemic risk that merely increases the cost of capital.

We are somewhat uncertain about Ofgem’s preference for the annuity approach to profiling pass-through revenue and are concerned that the application of different approaches to demand and generation could have unforeseen impacts. It could cause complications, for example, in the transfer of assets between generation and demand which can occur in some circumstances. We look forward to Ofgem’s proposals in the September document which will need to outline the mechanics of the inter-relationship between generation and demand expenditure

Ofgem specifically sought views on the treatment of tax and whether there should be a generic “tax wedge” or company specific adjustments. Our initial view is that the principle should be that the strength of the incentive for each company should be broadly equivalent on a post-tax basis. If this can be achieved via a generic approach this may well be simpler. However, it would be inappropriate for companies to be penalised or to make wind-fall gains as a result of historic tax positions which had arisen before the DG incentive scheme was developed or implemented. Similarly, care should be taken that any broad based company specific adjustment - covering all capital expenditure – should not be implemented in such a way that it materially affects the strength of the DG incentive between companies.

Innovation Funding Incentive (IFI)

We have previously commented that the IFI, if properly structured, may be a very useful mechanism to encourage distributors to give greater emphasis to the development work required to bring about network transformation. This continues to be our view and we believe that the scheme is increasingly being positioned to do so.

We welcome the relatively broad definition being applied to eligible projects and recognise the need to illustrate the benefits of such projects. However, the derivation of net present value of the benefits is likely to be speculative and somewhat problematic. In many cases it may be more appropriate to express these as a range of potential outcomes rather than as a single point. In addition, projects will sometimes need to be staged so that a piece of work is undertaken and reviewed, as an enabling step to further projects which move towards a solution to a particular issue with specific customer benefits. The process of justification and monitoring will need to recognise the existence and treatment of such enabling work.

It will also be important to recognise that the nature of such innovative projects is that not all will be successful. In its future review of the incentive Ofgem may well wish to look at research carried out in other, similar industries to see the level of success rate that should be expected.

We have previously argued the 90% pass-through proportion in the first year, reducing to 70% in the final year of the price control period may not be sufficient to balance.

- the mismatch between Ofgem's desire that the results from this investment in innovation should be rapidly shared among all distributors and the share of the investment that individual companies are expected to contribute;
- the need to kick-start the process; and
- the need for a sustained period of investment in innovation.

Nevertheless, we recognise Ofgem's intention to retain the pass-through percentages that have previously been proposed. Whilst we are disappointed by this we recognise the relatively short time to a review of the incentive in 2007 which will allow this issue to be re-visited in the light of some experience.

EDF Energy confirms its intention to be an active participant in the production of a common good practice guide for managing R&D projects should such an approach be adopted.

Registered Power Zones (RPZ)

We continue to be broadly supportive of the RPZ concept but are concerned that practical implementation may be problematic. We welcome the proposal to increase the incentive rate from £3 per kW to £4.50 per kW but are also still concerned about its rigidities and constraints. For example, the proposal to limit the scheme to two RPZ applications for registration per DNO per year seems arbitrary and restrictive and in our response to the main June consultation paper we have proposed an alternative approach.

We are concerned to ensure that arrangements to inform new generators or to agree with them new arrangements should not lead to the ability for a generator to frustrate development that could provide benefit to many, potentially including him. This, of course, needs to be in the context of the protection of the generators own legitimate interests. The final bullet point of paragraph of 3.3 could perhaps be qualified such that

it applies to a material commercial or technical impact rather than the current rather broad drafting.

We can envisage a number of circumstances where innovation involving DG with significant opportunities for replication would not seem to be supported by the RPZ concept. For example, an existing network and generator could be operating in such a way that at particular times or in certain circumstance that the generator needs to be constrained off of the network. A DNO is not incentivised to seek out innovatory and cost effective solutions to allow such constraint to be lifted by the RPZ concept as no new generation has been connected to the network.

A further perhaps similar situation arises with storage. The development of storage techniques could be a fruitful source of innovatory techniques associated with distributed generation. Clarity about the treatment of storage in both the DG incentive mechanism (e.g. does it attract the capacity incentive?) which would presumably be reflected into RPZs would be helpful.

Structure and scope of price control licence modifications

These comments should be read in conjunction with those submitted on behalf of all DNOs to the Legal Joint Working Group with which we fully concur.

We welcome the early publication of the draft licence condition covering the distributed generation incentive, the innovation funding incentive (IFI) and registered power zones.

Both the understanding and governance of these arrangements is made complex by many of the terms used being defined in the draft Regulatory Instructions and Guidance (RIGs). In our view there would be benefit in co-locating the definitions and the algebra of the regulatory entitlement within the licence condition. In particular, we believe that all the underlined terms in the draft text – there appear to be seven altogether – should be defined within the condition itself. The same would apply to any such key terms for the IFI and RPZ schemes. Given the novel and untested nature of these developments in network price regulation, and their susceptibility to political pressure, it is inappropriate (at least initially) for the definitions of operative terms to be located in a RIG-type document.

This is perhaps well illustrated by the arrangements for “high-cost” projects. The policy treatment of such projects is outlined in other consultation papers (although there is still some ambiguity about the details which is discussed elsewhere). However the policy approach does not seem to have been fully captured in the draft licence condition and/or in the RIGs. This omission is not clear from a reading of either of the documents in isolation and both must be carefully reviewed in order to identify the problem. This seems to be an unnecessary and clumsy approach with the risk of both error and of failure to identify such error.

We have undertaken an initial review of the algebra shown within it and we do have some concerns. The points are as follows:

1. The capital expenditure pass-through term is currently stated to be

$$GP_t = PIA_t \cdot \sum_{j=y}^t \left[\left(\frac{R}{1 - \frac{1}{(1+R)^p}} \right) \cdot gp_j \right]$$

However we do not think that this puts the correct price indexation to each year’s capital expenditure and PIA_t should be replaced by PIA_j and placed after the aggregator.

2. The network availability term is currently stated to be:

$$GC_t = PIA_t \cdot \sum_{i=1}^{ng_t} idr_i \cdot gci_{it} \cdot (ID_{it} - IDB_i)$$

The $(ID_{it} - IDB_i)$ element of this could in some circumstance could become negative and we suspect that this is incorrect and the result of the term should be zero or positive.

3. The term below defines the amount of capital cost entering the pass-through arrangements in year j

$$gp_j = ptr.(gps_j + gpc_j) - gpc_j - gtd_j$$

with gtd_j representing the assets transferred from DG capital expenditure to demand capital expenditure for year j. Whilst we recognise the need for this term we believe that there may be problems with the particular mechanism selected. As the gtd_j term will operate for 15 years it will not only reduce generator DUOS income to take account of the element of the cost that has been passed to the demand regulatory asset base but depending on the value used runs the risk of extracting the value that already been met by generators. This would not seem to be a correct or equitable treatment and emphasises the need to expand Paragraph 7 of the draft licence condition (see paragraph below).

In addition from a review of both the draft licence condition and the RIGs we do not believe that the treatment of high cost projects has been covered.

Paragraph 7 of the proposed licence condition indicates that an “appropriate” portion of the relevant remaining asset value may be re-allocated to the main price control RAV. This is not sufficiently precise and a clear statement of the details of the calculations that will be carried out should be included within the licence condition.

Similarly paragraph 5 indicates that GA_t will take a value ascribed by the Authority. We believe that the drafting of this clause should say this is a figure reasonably ascribed following consultation with the licensee.