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DEVELOPING NETWORK MONOPOLY PRICE CONTROLS – FEBRUARY 2003 UPDATE. OPEN LETTER ON DEVELOPING PRICE CONTROLS AND THE NEXT DNO PRICE CONTROL – MARCH 2003

We are responding to the above documents on behalf of the LE Group's three licensed distributors (EPN, LPN and SPN) and on behalf of its gas and electricity supply licensees, and its generation and metering businesses.

We welcome the opportunity to respond to the update paper and the open letter. We note and appreciate the open dialogue there has been between network operators and Ofgem and we look forward to continuing with this throughout the DNO price review.

Our detailed comments on the update paper are set out in Attachment A to this letter, our comments on the draft timetable in Attachment B. Our comments on the two papers from Frontier Economics (on dealing with uncertainty and on the incentive framework for price controls) are set out in attachments C and D respectively.

We can confirm to Ofgem that this letter and its attachments are not regarded as confidential and can be published on Ofgem's web-site.

Our key points are summarised below:

- **Retention of benefits:** under a five-year retention period, in present value terms DNOs retain approximately only around 30% of opex efficiencies, and only 10% of enduring capex savings. The retained proportion should be increased to 50% for both categories to overcome the increasing difficulty in achieving incremental efficiencies and to maximise long-term customer welfare.

- **Opex incentives:** we support the establishment of a mechanism that allows DNOs to retain opex efficiencies for a fixed period of time. We detail certain desirable features of such scheme.

- **Capex incentives**: the current capex incentive must be based on both the incremental return and regulatory depreciation, in line with commitments made by Ofgem at the last review. These are not alternatives as currently being suggested by Ofgem.

- **Total cost modelling**: we support the development of this approach provided it is considered in concert with the output from other techniques to produce sustainable outcomes.

- **Treatment of mergers:** Ofgem needs to ensure that in applying its former policy (based on £12.5m fixed cost savings) it does not double count merger and other efficiency savings. Ofgem should allow for the recovery of restructuring and reorganisation costs, and allow companies to retain 50% of the net present value of merger benefits.

- **Quality of supply targets:** customers' willingness to pay, (or possibly societal costs as a proxy) should inform targets. In this forthcoming review, the allowed funding should be explicitly related to the work required to achieve the targets.

- **Research and development:** Ofgem needs to give consideration to the funding of research and development expenditure, particularly in the context of increased levels of distributed generation.

- **Training and development of technical staff:** the funding of training and development of the relevant technical staff needs to be considered, particularly in view of the drop in the number of relevant university degree courses, and the demands that will be imposed by distributed generation.

- **Uncertainty:** we agree with many of Frontier Economics' conclusions, with the notable exception of investor diversification, which we regard as unavailable in practice. We point out the need for DNOs to have enforceable rights regarding the activation of uncertainty mechanisms.

- **Exemptions:** we see no justification to remove the exemption arrangements for the current guaranteed service standards.

- **Taxation:** we agree that the current generic "tax wedge" will be inadequate to fund our tax obligations given recent and prospective changes to tax rules.

- **Distributed generation:** unless a substantial allowance is provided, capital and operational costs should be passed through, supplemented by a revenue driver based incentive (e.g. kWs of installed capacity) to encourage increased levels of proactivity by DNOs.

- **New obligations:** we list a range of new obligations that have yet to be funded, for which price control recovery is necessary.

- **Pensions:** distributors have inherited pension obligations that are subject to statutory protection. The full recovery of both ongoing and periodic costs needs to be appropriately funded through the price control.

- **Financial model and information request:** we support Ofgem's work-stream and will actively contribute to help it meet its objectives.

- **Cost of capital:** there is strong evidence for increased equity risk and debt premiums, compared to Ofgem's 1999 DPCR estimates.

- **Cost of historic debt:** the costs of historic debt should be recoverable through the price control.

- **Metering costs:** there must be no "stranding" of historic metering costs.

- **Timetable:** work-streams should be organised to ensure that, as far as is possible, process is determined before data requirements are established.

We would welcome the opportunity to talk through these points with you. We would also like to discuss with you our response to the DTI/BPI investigation into the October 2002 storms so that you have the full picture, and we can reach a shared understanding regarding any potential impact upon the review.

If you have any comments on, or questions about, this response please telephone me on 01293 657546, or write to me at; Seeboard Power Networks, Forest Gate, Brighton road, Crawley, W. Sussex, RH11 9BH.

Yours sincerely

Paul Delamare
Head of Price Control Review

Attachment A

DEVELOPING NETWORK MONOPOLY PRICE CONTROLS: FEBRUARY 2003 UPDATE

Consistency of price controls

Transmission framework: Ofgem asks whether there are any aspects of the electricity transmission framework that should be applied in electricity distribution, and if so what would be the most appropriate timing for doing so, including the regulatory, technical and commercial issues that would arise.

In addressing this question, we believe that the main areas to consider are as set out below:

The System Operator ("SO") / Transmission Operator ("TO") split: in our view, the present level of our internal and/or external SO costs is insufficient to warrant separate price control treatment. However, we recognise that this situation is likely to change in future with the development of actively managed networks in response to increased levels of distributed generation. It is clearly important for Ofgem to ensure that such costs (both capex and opex) are funded and that companies are provided with appropriate incentives for preparing for, and managing, increased levels of such generation. A separate SO control could achieve this.

New arrangements could possibly be established along the lines of the current NGC incentive scheme. It is likely that SO costs, in common with other aspects of distributed generation, will be difficult to predict, and so any incentive scheme would need to be flexible and provide, at least initially, a high degree of cost pass through whilst protecting both distributors and customers from extremes. The current approach adopted for NGC using sharing factors, caps and collars would be one form of arrangement that could be used to meet these requirements.

Distribution access capacity scheme – firm tradeable rights: Ofgem is currently suggesting that NGC bring forward proposals for firm, tradeable access rights to its transmission system. This is intended to assist NGC in making investment choices regarding "deep" transmission system capacity through responding to users' willingness to pay – expressed through a sale mechanism such as an auction.

It is difficult to see how a tradeable access scheme could work in respect of the majority of DNO users. The level of "deep" system capacity on a distribution network is typically a function of the demand pattern of many thousands of individual users (who will themselves be supplied by a number of electricity suppliers) and mandatory planning standards. This contrasts strongly with NGC's transmission system that is characterised by a small number of relatively large and sophisticated connectees.

In general, the resolution of any “deep” distribution system constraints could not be meaningfully associated with individual demand customers/their suppliers or distributed generators. Where a connectee’s new or increased demand requires specific reinforcement, a connection charge is available (under the current arrangements) to recover the relevant costs. It is likely that a market for tradeable distribution access rights would be illiquid as most users (such as domestic customers/their suppliers) would have no interest in taking part, and would therefore not provide useful investment signals to distributors, and certainly not over any extended timescales.

In short, tradeable distribution access rights would unnecessarily increase transaction costs and risks for distributed generators and suppliers, and DNOs do not need such a scheme to make efficient investment decisions.

Capital expenditure at grid supply points: The efficient timing of the replacement of DNO-NGC owned assets is an issue that Ofgem needs to consider in the review. In particular, operational constraints will be a major factor in the timing of works. The price control will need to provide distributors with adequate funding for this work. Similarly, NGC may need assurance about the increased funding of work required within the next distribution price control period, which is beyond its current control.

<u>Assessing costs and incentives for efficiency</u>

Unit cost analysis: any unit cost analysis undertaken by Ofgem must be supported by agreed and detailed activity descriptions. Activity descriptions currently referred to in draft regulatory accounting guidelines are not sufficiently developed for robust inter-company comparisons to be made.

Merger policies: we agree that it will be necessary for Ofgem to consider how to take account of its various policies for treating merger savings.

Where Ofgem has required a minimum level of savings (£12.5m in the case of our EPN acquisition) it will be essential to distinguish between merger efficiencies and other cost savings to avoid the potential double counting of savings in its efficiency analysis, and to avoid inappropriate comparisons between companies. Savings made under mergers covered by Ofgem’s current merger policy (i.e. that requires a £32m payment for loss of a comparator) do not need any special treatment in respect of assumed fixed cost reductions, but can be considered ex post alongside other efficiencies.

Ofgem needs to make an appropriate allowance for restructuring and integration expenditures when setting targets for achieving reasonably efficient cost levels in the future. Such costs are considerable, but benefit customers in the long run after a retention period comes to an end. It would clearly be appropriate therefore for merger/integration costs to be recoverable through the price control. Indeed, Ofgem has already recognised this in its discussions with us regarding our Seeboard acquisition.

Ofgem should allow companies to retain 50% of the net present value of merger benefit after allowing for the full recovery of restructuring and reorganisation costs. Ofgem will need to take account of restructuring and integration expenditures when carrying out comparative efficiency analysis between companies.

Total cost modelling: our detailed comments on total cost modelling are set out in our response to Frontier Economic's (FE's) paper on incentives (Attachments C and D of this response).

In general, we foresee considerable difficulties in devising a robust total cost model, particularly concerning an appropriate valuation of capital expenditure, the determination of common (i.e. opex and capex) cost drivers, and differences in the marginal rate of substitution (which is particularly relevant to any total cost/quality models). However, separate opex and capex benchmarking is prone to cost allocation issues that may produce inappropriate, or even unsustainable, outcomes. We therefore continue to support Ofgem's attempt to develop a total cost approach but believe that it should be used as a check on the results of separate opex/capex analysis.

Frontier performance approach: Ofgem asks whether the frontier performance approach used at the last review remains appropriate. There would appear to be a number of aspects to this question:

- Was Ofgem's analysis at the last review robust?
- Should companies be required to move their respective cost levels towards that of the frontier company?
- And if so, over what period?
- Should frontier companies be rewarded?

In our view, the analysis used last time was not robust. In particular, comparisons were based on a limited set of data points that were subject to numerous, material, and opaque adjustments by Ofgem and its advisors. Some of these adjustments will not be required for the next review (such as those that dealt with meter reading and data aggregation costs moving to supply). However, remaining capitalisation policy and other differences mean that inappropriate cost comparisons remain a risk.

In addition, the fact that the two largest distribution companies were shown to be the most efficient gives concern that the adjustments made by the consultants for economies of scale were incorrect – resulting in the setting of inappropriate efficiency targets for all other companies.

The risk to companies and customers would be high if Ofgem seeks a high rate of "catch-up" (in the last review, Ofgem asked non-frontier companies to move, over time, 75% of the distance to the frontier). Catch-up rates should reflect, amongst other matters, the degree of error in the model. In addition, frontier companies may have low costs because they are adopting a high asset risk strategy, which could in time lead to infrastructure failure. A frontier approach may force other companies to take such risks also. This would not be in customers' interests.

Frontier companies should be rewarded. Indeed, we would also expect the frontier companies to benefit from relatively large rewards as an incentive to reduce the risk of Ofgem setting unsustainable cost levels (a risk if inappropriate adjustments are made to frontier companies' cost levels).

Setting "allowed" costs to the level of average industry costs could achieve both ends – providing incentives to less efficient companies to catch-up with the average, whilst rewarding those who have done better than average. It would also help ensure that "allowed" cost levels are not inappropriately ratcheted down to the lowest level of costs. Such a level may not be sustainable and may represent an inappropriate trade off between short and long-term asset risk being taken by the company concerned.

Capex efficiency incentive: we are surprised and concerned to note that Ofgem sees (Appendix 3) the retention of the cost of capital and the regulatory depreciation on capex efficiencies as alternatives (we note that Frontier Economics do not take this view in their recent incentives paper). It would appear to us that Ofgem has wrongly interpreted Ofwat's approach. The commitment given at the last review to replace projected spending with actuals on a rolling basis after the lapse of five years made no such distinction, and none was expected when we accepted Ofgem's final proposals. Ofgem must allow companies to retain the benefits of both the cost of capital and depreciation on capex savings in line with its original DPCR3 commitment, and companies' legitimate expectations.

The capital efficiency incentive is based on comparisons between actual and forecast net capex. Therefore, it is important that suitable adjustment mechanisms are established to take into account the impact of all unforeseen events on capital expenditure. In particular, capital expenditure in relation to the growth of distributed generation is likely to be difficult to predict. Without such mechanisms the incentives to connect distributed generation will be undermined, if the associated expenditure needs to be higher than forecast.

We agree with Ofgem that it is sensible to reflect the extent of any failure to meet 2004/05 quality of supply targets, in modifying the level of any benefits obtained from the capex efficiency incentive mechanism. A sliding scale mechanism would be appropriate. However, as Ofgem recognises, there is a background level of variability in quality of supply performance year on year. This will need to be taken into account in designing a sliding scale. Taking average performance may achieve this. Alternatively, a zero penalty rate could be attached to performance within a number of standard deviations from mean performance.

Asset risk management: our capex programmes are rooted in robust and audited (by Ofgem) ARM practices and, as such, ought not to require detailed review by Ofgem. Although we would not expect Ofgem to rely wholly on its ARM work, we would equally not expect it to replace our submission with its own model, and make arbitrary cuts of the type seen in the last review.

Retention periods for efficiency savings: we believe that it is appropriate to share the benefits of efficiencies (capex and opex) equally between companies and customers (in net present value terms – and assuming an indefinite horizon). In the context of the current capex and opex efficiency incentives, a 50:50 sharing factor implies, other things being equal, longer retention periods. However, it is of course possible to choose other retention periods and still achieve a 50:50 sharing outcome. We believe that this approach should be taken with capex, non-operational capex, and opex.

As Ofgem knows, after twelve years of successful incentive regulation, further efficiencies are increasingly hard to find, and often require significant investment in information technology ("IT") and associated systems. Efficiency initiatives are often risky in terms of not achieving the relevant business case (particularly innovative IT projects). It is appropriate that Ofgem increases the proportion of savings retained by companies to compensate for such risks, and allow for cost recovery. This will benefit customers in the long term.

We note from the last review, that Ofgem removed one-off costs (for example staff severance costs) from its analysis of standardised controllable costs, and then did not fully add them back in determining allowed revenue. Such an approach is not compatible with productivity improvement initiatives.

Research and development ("R&D"): the lack of R&D effort, exhibited by most UK distribution companies' needs to be corrected, particularly given the developments that will be required by the development of distributed generation. We have discussed the issue with Ofgem's Technical Directorate, who is aware of the need and has considered how best to fund such costs. We suggest that distributors are given an explicit opex allowance for R&D projects (whether they turn out to be commercially viable or not).

In suggesting this, we recognise the need for Ofgem to be able to seek evidence of project activity. We also recognise that the benefits of research are often difficult to measure. However, companies with a prove track record of innovation and/or success can demonstrate sufficient credibility.

Training and development of technical staff: companies are generally experiencing an ageing population in respect of engineering and craft skills. There has also been a decline in the UK of relevant degree level courses. These trends need to be addressed, particularly in view of the forthcoming demands to be imposed by the growth of distributed generation.

Non-operational capital: IT expenditure, in particular, will be an important element in achieving future efficiency savings, and in managing increasing levels of distributed generation through the use of active network control technology for example. It is therefore appropriate that companies are adequately incentivised and funded in this regard.

Non-operational capex could continue to be funded through opex allowances, or through the RAV. Either way, it is important that the appropriate share of any efficiency savings is the same (i.e. 50% in NPV terms).

If a RAV approach is taken, efficient non-operational capex spending should be added to it even where this is in excess of Ofgem's forecast. The low risk nature of this approach would imply that the "normal" sector cost of capital would apply. Depreciation periods should be set in line with the goal of balancing efficiency retention between companies and customers.

We believe that it is appropriate to retain some existing elements of non-operational capex in opex, such as tools and office furniture etc. An appropriate opex allowance will need to be retained for these. We would welcome the opportunity to work with Ofgem in establishing the appropriate Regulatory Accounting Guideline definitions.

Opex efficiency: we support Ofgem's commitment to allowing companies to retain opex efficiency savings for a fixed period of time. The Ofwat approach forms a suitable basis for such a scheme. However, we have a number of concerns with certain aspects of their methodology, which are set out in Attachment D.

We believe that the desirable features of a rolling adjustment mechanism are:

- Companies retain 50% of the net present value of savings achieved;
- Unforeseen costs are excluded from the calculation of the incentive payment;
- The amount retained each year should be the incremental saving compared to the previous year;
- A forecast should be made of the likely incremental out-performance in the final year of the current price control.

We note that increasingly anticipating savings (by Ofgem - through a downward sloping opex glide path, for example) reduces the incentive power of the proposed "rolling" incentive

<u>Developing the overall incentive and price control framework.</u>

Incentive/uncertainty framework: our detailed comments on Ofgem/Frontier's thoughts on the development of an incentive/uncertainty framework are set out in Attachment C.

Ofgem's current treatment of the impact of unforeseen events is bespoke and of uncertain outcome. For example, its approach to lane rental costs. FE's uncertainty paper usefully sets out the range of techniques available to regulators for dealing with unforeseen cost shocks. However, whatever the specific mechanism adopted going forward (for example, logging up and interim reviews can be used), Ofgem must establish clear and enforceable rights for the affected party to activate the process. A suitable licence condition would achieve this purpose.

Losses: Ofgem has recently consulted on the losses incentive and clearly has an ambitious timetable to bring forward proposals in summer 2003. In our response to the consultation we expressed concern that Ofgem must understand the marginal cost of losses reduction before strengthening incentives. I.e. increasing incentives without understanding the high costs of loss reduction would not achieve Ofgem's aims (losses would not fall) and would increase DNO risk. Also, difficult measurement issues need to be overcome, many of which are not under DNO control, before we could agree to an increased losses incentive.

Customer willingness to pay: we support Ofgem's general approach to attempting to establish customer preferences. It is important that DNOs are involved throughout the process and that their comments on the survey are appropriately taken on board, particularly with regard to the proposed survey's terms of reference (which we await). Distributors will also want to discuss with Ofgem how the survey results are interpreted and used. It is important that regional variations in customer preferences are identified (e.g. we would expect the requirements of commercial customers in the centre of London to be quite different from the generality of customers). It may also be appropriate for Ofgem to develop a view on the societal costs of power outages in order to validate the perspective provided by customers.

Use of disaggregated quality of supply data: we continue to support the work of the industry/Ofgem working group. In particular, we are keen to work with Ofgem to develop a process for developing future quality of supply targets. The result of this process can then be used to inform the planning assumptions against which companies can construct their cost forecasts.

The October 2002 storms: Ofgem refers to the DTI/BPI report and states that in taking forward its work on quality of service, it will pay particular attention to the recommendations of the report. We would like to have the opportunity to discuss with Ofgem how this should be achieved. We would also wish to take Ofgem through our response to DTI to ensure that Ofgem has all the information it needs to reach a fully informed view.

Guaranteed and overall standards of performance: throughout the development of Ofgem's Investment and Incentives Project ("IIP") scheme, we pointed out the increasing double jeopardy. These were arising from the (then) developing guaranteed standards, overall standard, capex efficiency and IIP regimes, together with new fining powers. Ofgem should work to clarify the incentive framework and remove these double jeopardies wherever possible. In this context, the overall standard concerned with restoration of supply replicates incentives on speedy restoration contained within the IIP scheme and should be discontinued.

In general, guaranteed standards remain a valuable protection for customers and do not need to be changed, in both scope and level of compensation (apart from the multiple interruptions standard, for which there should not be bespoke exemptions arrangements).

Ofgem has also proposed a complex and onerous set of standards to support the development of competition in connections, and is presently asking DNOs to collect information on their performance in respect of these, as if the standards were in operation. This significant extension to the number and scope of the standards has not been justified, and should only be considered at the price control review as part of the development of the overall incentive framework.

Exemptions: the need for exemptions built into the guaranteed standards regime (except multiple interruptions) remains sensible, and generally replicate the "Force Majeure" clauses used in contracts in competitive markets. They have not, in general, raised any great issue. It is important to keep them in order that DNOs are only penalised in respect of matters under their control. Precisely defining these circumstances in advance will necessarily be a challenge, but remains a necessary one.

As was said by many companies at the time of their creation, the exemption rules covering multiple interruptions (triggered by an event impacting on more than half of one million customers nationally) is arbitrary and potentially unfair (as it cannot cover localised incidents). Ofgem should abandon them and incorporate the general regime for exceptional events into this standard.

Automatic payment of GS2: remains impractical because of the significant costs and practical difficulty (we would need access to millions of premises to establish the electrical phase) associated with establishing phase connectivity to an appropriate standard of accuracy. There would also be considerable ongoing data maintenance costs. The costs outweigh the benefits.

The IIP incentive scheme: quality of supply targets should be established for the long term so that DNOs can plan ahead, and internally cost justify improvement schemes towards the latter part of the price control period. However, such an approach will only be worthwhile if it is associated with a commitment to appropriate levels of funding. A longer duration price control period would not only facilitate this, but it could also help to increase the incentive power of capex and opex efficiency mechanisms by enabling companies to retain savings for long periods. Of course, longer retention periods are not necessarily a function of longer price control period durations - please see the options discussed in Attachment C.

<u>Financial issues</u>

Cost of capital: we agree with Ofgem that an inappropriately low cost of capital would act as a disincentive to DNOs to invest.

Given the generally long-term nature of distribution, it is important that Ofgem puts in place a stable and predictable framework and mechanism for assessing the cost of capital. We therefore welcome the work of the joint regulators, and the report from Smithers and Co. Companies have also sponsored some work by Oxera, a summary of which is to be submitted to Ofgem and will be published.

Oxera highlights two areas where different parameter estimates are appropriate compared to Ofgem's 1999 DPCR estimates; the equity risk premium (ERP), and the debt premium.

- Using a forward-looking ERP (Oxera note that the Competition Commission emphasises higher historical estimates of ERP), Oxera identify strong evidence from academic studies in 2002 for higher levels to be set. Recent stock-market volatility would point to further ERP rises.

- Regarding debt premia, Oxera identify increases following the downgrading of DNO credit ratings. Any increased gearing levels (beyond those assumed at the last review) would lower credit ratings further.

Risk levels can also be increased through new or enhanced regulatory incentive arrangements (for example, the IIP scheme). Such changes could increase the ERP further and be associated with higher risk premiums

Taxation: Ofgem is correct to raise this important issue. Recent and forthcoming changes to the tax rules governing the taxation of the DNOs mean that the existing tax wedge will be insufficient going forward. We would be keen to work with Ofgem to develop revised arrangements.

Gearing: we support the view that high levels of gearing reduce financial flexibility. We believe that it would be inappropriate for Ofgem to incentivise higher gearing levels (beyond the 50% assumed at the last price control) by assuming such levels in its cost of capital calculations.

Fixed costs of debt: we believe that it remains appropriate for Ofgem to allow DNOs to recover the costs of fixed rate long term debt where this is part of a historic financing portfolio, accumulated over a period of time at market rates prevailing at the time of each issue.

Asset disposals: the standard distribution licence condition dealing with asset disposal is designed to protect the operational capability of the distribution system. The condition has essentially remained unaltered since privatisation and appears to have served its purpose well. We see no need to extend these arrangements. We would request that Ofgem clarifies what changes in the regulatory framework and/or corporate structures and financing arrangements are driving the alleged need for change.

Depreciation profiles: Ofgem need to ensure that DNOs can finance their activity whilst remaining comfortably within the relevant financial parameters. Accelerated regulatory depreciation profiles is one approach to achieving this and may be appropriate in the short term, provided that the long term profile of costs and income are understood.

The adjustment made in respect of Seebaord, Swalec and Norweb tends to have the effect of rapidly eroding RAV values, and thereby eroding the levels of regulatory return and depreciation. Over time, and without any countervailing investment programme, this will erode the financial strength of the DNOs and make it harder to maintain investment grade credit ratings.

The full or partial expensing of replacement expenditure can be used to adjust cash profiles. However, on its own, we do not favour such an approach in that it provides no profit/return opportunity for the DNOs. Repex can, where unit costs are relatively practicable, be used in association with an incentive arrangement to overcome this problem. For example, where a unit cost allowance can be developed and efficiency savings retained. The arrangements in respect of Transco's iron pipe replacement programme are of this type.

As Ofgem is aware, much of the current distribution infrastructure was built in the 1950s and 60s. There is a need to further develop our understanding of the condition of these assets (particularly cables), for which more research and development are required. It will also be necessary to begin replacing some of these assets during the next price control period. It is sensible therefore for Ofgem to consider the longer-term profile of costs over at least the next two five year price control periods, i.e. out to March 2015. Beyond that period, cost estimates are likely to be unreliable because of unforeseeable technological and other developments.

Financial modelling: we are pleased to be able to assist Ofgem with the development of its financial models. At the last review, considerable effort was expended on both sides in attempting to understand the companies' submissions and the use to which Ofgem put them. The proposed shared work should greatly reduce the need for such effort this time.

Financial ratios: we agree that it is appropriate for Ofgem to focus its key financial ratios on the individual licensees given the nature of the financial ring fencing provisions.

The next DNO price control

Distributed generation ("DG") incentive scheme: our views on Ofgem's January proposals are set out in our response to the open letter. In summary, we believe the DG costs are currently too uncertain to be included within the main price control (at least without additional re-opener/logging-up protections), unless of course the relevant allowed revenue was substantial. Therefore, we suggest pass through of costs, supplemented by a revenue driver type incentive (e.g. £ per kW of installed capacity) to encourage DNOs to positively seek out DG connection opportunities.

Correction factors: the normal arrangements for carrying forward any over or under recoveries should be maintained.

Metering costs: we agree that the price control review will need to consider the development of competition in metering services. We believe that there are a number of aspects to this:

- Stranded and fixed costs incurred by distribution businesses should be recoverable through the distribution price control until fully depreciated;

- New DNO obligations will need to be funded (see below);

- There should be no discrimination in favour of competing metering business, whether they be market incumbents or new entrants;

- DNOs can charge market rates for their metering services once competition is established.

New obligations: a number of unremunerated costs have arisen, or are likely to arise, in the current price control period which need to be included in allowed revenues in the next period:

- Section 74A NRSWA charges (known as "lane rental" charges). Costs arising from the trial being conducted in LB Camden – new legal requirement

- Further costs arising from a possible new street works bill – potential new legal requirements

- The central London Congestion Charge – new legal requirement.

- The costs of producing the Long term Development Statement (LC25) – new Ofgem requirement

- Enron bad debts – unforeseen cost outside of cost of capital assumption

- Meter Asset Provider/Meter Asset Maintainer split - IT and process costs – new Ofgem requirement

- The costs of establishing an Urgent Metering Service – new Ofgem requirement

- Cost of compliance (largely IT) with new arrangements for the rating of meters – new legal requirement

- Ongoing operating costs arising from the IIP

- The cost of complying with the new Electricity Supply Continuity and Quality regulations – new legal requirement

- The cost of complying with the revised connection charge regulations – revised legal requirement

- Post-September 11 (and other events such as floods) insurance costs/higher excess cost thresholds – unforeseen cost shock(s)

- Meter "red-lining" costs (meters withdrawn by Ofgem from the list of certifiable meters, requiring premature replacement) – new Ofgem requirement

Future unforeseen events should be subject to predetermined regulatory treatment, and be the subject of enforceable rights.

Pensions: It is appropriate that pensions costs are recovered through the price control, including any scheme deficits. Ongoing pension obligations relating to the electricity supply defined benefit scheme pre-date vesting and are the result of nationalised industry arrangements, and are preserved by statute (the Electricity Act 1989). It would be inappropriate to make cost recovery conditional on misleading comparisons with current competitive practice.

We also note that Ofgem needs to take care when comparing companies to ensure that the cost of pensions contributions assumptions are consistent. It would be inappropriate to set “allowed” cost levels in relation to a “frontier” company that is enjoying a pensions contribution window.

Any price control consideration of pension scheme funding requirements will need to consider timing of planned actuarial variations, which cannot be accelerated within scheme rules.

The main impact of FRS17 will be to disclose pension scheme deficits in DNO’s statutory and regulatory accounts. Any such deficits will, of course, have an impact on a DNO’s ability to maintain credit ratings unless funding arrangements through the price control are clear to the credit agencies.

Information requests: we support Ofgem’s work on the information gathering process and templates. We also support work on providing planning assumptions, and would actively wish to contribute to this.

We agree that it is important to have an understanding of the impact of the price control beyond 2010, on both the financial position of the companies and the likely pricing path to consumers. In particular, it will be important to consider the longer term impact, and interaction, of any accelerated regulatory depreciation arrangements, scenarios for the development of distributed generation, and programmes of asset renewal.

We believe that the review should require information on, and consider, at least two complete future price control periods. Should price control periods remain at five years in duration, this would mean considering in terms of cost and revenue profiles covering April 2005 to at least March 2015.

Publication of business plan: Ofgem suggests that a way of ensuring that there is an appropriate level of transparency and openness in the information companies submit to Ofgem would be to require DNOs to publish their business plans.

We see no need to publish detailed confidential internal business plans as these can be adequately scrutinised by Ofgem.

We do believe that it is necessary to require that the Board of the licence holder and its parent company endorse the strategy and information set in a company’s submission. Licensees are already under a criminal liability to provide accurate data to the regulator.

We see no need for our submission to be subject to some form of audit, as it will be scrutinised by Ofgem and/or its consultants. It would also be difficult to construct an audit opinion on forecast data that the audit profession would accept, understand, and be contractually bound by.

LE Group plc
April 2003

Attachment B

OPENING LETTER ON DEVELOPING NETWORK MONOPOLY PRICE CONTROLS AND THE NEXT PRICE CONTROL REVIEW OF THE ELECTRICITY DISTRIBUTION NETWORK OPERATORS (DNOS)

Introduction: we welcome Ofgem's more detailed plans for the forthcoming review of Distribution Price Controls. We have a number of observations and comments to make on the timetable, which are set out below.

Interdependencies: Ofgem has set itself an ambitious work programme. Indeed, because it is addressing many issues from first principles (which we applaud), it will need to consider the interdependencies between the elements as the detail emerges. For example:

- The choice and design of any comparative econometrics will determine data requirements, and therefore the detailed BPQ designs;
- The scope and strength of any revised incentive arrangements will affect cost levels (e.g. a stronger losses incentive will increase capex requirements etc).

Planning assumptions: with respect to forecast information, it will be important that planning assumptions are determined well in advance. This should include realistic assumptions about incentive arrangements. We would wish to contribute to the development of these to ensure that regional factors are considered.

Work-streams: Ofgem's work-streams may be better recast into:

- Resolve the policy questions;
- Determine the data requirements;
- Perform the calculations (with feedback loops as required).

Financial modelling: Ofgem's financial model is not scheduled for completion until four months after the forecast BPQ submission is complete. Ideally, we would prefer to see the model completed before the forecast BPQ is designed. This will make it easier to understand why questions have been asked and how the results will be used.

Total cost modelling: we would also like to see the question of total cost modelling (due to be initiated in May 2003) developed further before the historic data BPQ is submitted. This BPQ will need to be designed in a way that ensures that the right data is collected to support a total cost model.

Distributed generation: we understand Ofgem's desire to collect some information on distributed generation early, since this is a new area. However, we do not understand why the final submission of DG cost projections should be before the main base cost estimates. We believe that the impact of different DG development scenarios needs to be thought of as variations to our base cost projections.

Cost estimates: the review is a forward-looking exercise. However, we note that forecast data are required (December 2003) only four months (allowing for a month's drafting) prior to the finalised cost projects. This seems tight.

LE Group
April 2003

Developing Network Monopoly Price Controls: Workstream A: Regulatory Mechanisms for Uncertainty

General: The LE Group welcomes the focus that Ofgem is giving to developing appropriate mechanisms for dealing with uncertainty. A key requirement underpinning all of this work is that, irrespective of the detailed mechanisms developed, they must be subject to a formal regulatory governance framework. For example, any logging up arrangements must be subject to formal rights set out in distribution licences. Not to do so would introduce subjectivity into the process that would itself be a source of uncertainty – which we do not believe is Ofgem's intention. In particular, it is essential that the mechanisms ensure that:

- The balance of risk is appropriately allocated between companies and customers. This is vital to ensure that appropriate levels of investment can be attracted to fund expenditure plans; and

- Managers are provided, where appropriate, with sufficient incentives to innovate.

In theory, we agree that financially diversifiable risks have no effect on the sector cost of capital but can impose uncertainty on managers and hence may affect incentives. Indeed, we believe that Frontier's focus on managerial incentives is a valuable insight that advances understanding on the subject of regulatory incentives (in particular the understanding that managers cannot diversify the risks on them).

We also believe that, in practice, the current ownership structure of the electricity distribution industry prevents investors from building a portfolio that effectively spreads industry specific risks. Consequently, it is our view that the majority of industry specific risks are not in practice diversifiable.

We also note that Ofgem has a statutory duty to secure that licence holders are able to finance the relevant activities arising from their obligations. This objective is in relation to individual licensees, and not licensees in aggregate.

The decision making process: Frontier Economics (FE) have outlined eight criteria by which new sources of uncertainty will be judged. At a high level, the associated processes outlined in the document with respect to predictability (including predictability of impact), separability and controllability appear generally sensible. However, we are concerned with certain aspects of the materiality, diversifiability and correlation processes. Our concerns are:

- No process is proposed for dealing with those costs which do not meet the materiality threshold, but exceed it in aggregate;

- The rationale underpinning the use of diversifiability, to judge any uncertainty, is flawed; and

- The use of benchmarking to assess the costs of uncertainties, which are either correlated across companies and/or correlated across time, will actually increase regulatory risk.

These are discussed in more detail below

Materiality: we agree that:

- "The regulator must have regard for the potential effect that **any** [our emphasis] given source of uncertainty could have on the costs of regulated companies; and

- That it is important to define what constitutes a material impact."

The latter will be difficult to specify and we believe that Ofgem should work with companies to try and determine suitable threshold arrangements.

Irrespective of the materiality level, there also needs to be a process for dealing with those uncertainties having individual costs below the threshold, but which exceed it in aggregate. We therefore do not agree with FE's view that if a particular uncertainty does not meet the threshold then the regulator need take no specific action. It is important that these costs are identified and appropriately treated.

For example, consider the case where a number of new regulatory obligations are placed on a company during a price control period, resulting in increased opex, none of which individually meet the threshold but which in aggregate result in a material impact. Aggregate "immaterial" uncertainty costs would also need to be taken into account in any cost benchmarking or yardstick regulation, otherwise the costs of the company concerned will appear relatively inefficient compared to its peers. This could then lead to an inappropriate revenue reduction if it is required to catch up, or meet, the "efficient" cost level.

Diversifiability: a key principle of FE's proposed approach is the application of diversifiability to determine any impacts on the cost of capital for a given uncertainty. As we have stated above, we agree in theory with the notion that the rational investor can purchase a balanced portfolio of shares to spread his exposure to a particular industry specific risk. However, we do not believe that this rationale is applicable to industry specific risks associated with electricity distribution. The reasons for this are:

- Investors cannot currently purchase shares in hardy any electricity distribution companies; and

- Even if an investor could purchase such shares, there are no distribution-only companies publicly quoted. Distribution companies are either part of vertically integrated companies or large overseas conglomerates.

Consequently, to purchase shares in all distribution companies the rational investor would also have to purchase shares to offset the risks arising from the other businesses of that particular group. This is impractical.

A prerequisite of the theory of investor diversification is that a rational investor can purchase shares in the relevant companies. Therefore, distribution industry specific risks are not, in practice, diversifiable.

Correlation across companies and over time: we are concerned that benchmarking coupled with yardstick competition is seen by FE as the most appropriate methodology to deal with risks which are correlated across companies and correlated over time. In particular, we disagree with the premise that for negatively correlated risks, which FE admits increases company specific risk, the rational investor can mitigate their exposure by purchasing shares in a number of distribution companies. As we have stated above, we do believe it possible for a rational investor to diversify distribution specific risks.

We believe that benchmarking can, if used carefully, inform the likely level of efficient cost for a given uncertainty. However, we do not believe it is robust enough to be used mechanistically and applied as part of a formal yardstick competition incentive mechanism. Amongst other things, we are concern is that the use of yardstick competition may result in efficient companies being forced into insolvency or inefficient companies achieving windfall gains.

Yardstick competition assumes that, for a given uncertainty, a cost function can be developed which explains all the material differences between companies. The remaining differences between companies are then assumed to be due to differences in efficiency. However, if a relevant company specific explanatory factor has not been included in the cost function then there is a risk that a company's costs may be overstated. Consequently, it may be impossible for them to reach the yardstick level without inappropriately reducing expenditure on other aspects (e.g. network resilience) or becoming insolvent. Conversely, it is also possible for a company's costs to be understated allowing it to achieve windfall gains, as their costs would incorrectly be assumed to be less than the yardstick. Both outcomes are clearly perverse.

The risks inherent in the use of benchmarking and yardstick competition can be reduced if they are used in conjunction with other techniques to produce a likely range of costs for a given uncertainty. The risk may also be mitigated if weaker yardsticks are initially applied (for example, where companies are benchmarked against the lower quartile of performers). Such an approach would also provide managers with a strong incentive to innovate in areas of uncertainty, as additional returns could be achieved.

Application of decision-making process: in general, FE's application of the decision criteria to the chosen example uncertainties has produced broadly sensible solutions. However, we note that financial diversifiability is not generally applicable to them.

The table below sets out our views on the optimal regulatory treatment of licence fees, NGC exit charges, one off IT costs, and lane rental. The proposals for treatment of severe weather exemptions and for distributed generation are discussed in more detail below:

Uncertainty	Optimal regulation
Licence fees	We agree that Ofgem's costs are uncontrollable by DNOs and passthrough of costs is appropriate.
NGC exit charges	DNOs have little influence over NGC's connection costs. This is likely to remain the case and therefore the current cost passthrough mechanism remains appropriate.
One-off IT costs	The application of a "beat the target" incentive mechanism would be appropriate if the costs are truly controllable. If the latter were not the case then a cost passthrough mechanism would be appropriate. As discussed above, we would not support the mechanistic use of benchmarking. We believe that the benchmark level could be set at the lower quartile (i.e. in efficiency terms) of costs for all companies since errors present in the calculation of the benchmark would significantly increase the risk facing companies.
Lane rental	Due to the extremely high level of uncertainty over the costs associated with lane rental, we agree that in the next price control period an interim scheme is required. Given the high level of uncertainty, with respect to the costs, we would prefer a cost passthrough mechanism, at least initially.

GSS Severe weather exemption: we do not believe that there is any justification for removing the severe weather exemption. FE recommend its removal because it weakens incentives to restore supplies. This is not true. Companies face a range of incentives that provide strong incentives for them to respond effectively to severe weather events. These include:

- Primary duty to run efficient and co-ordinated electricity distribution systems set out in the Electricity Act 1989 (as amended) – for a breach of which Ofgem can impose fines;
- IIP scheme (where Ofgem are unlikely to adjust performance for inefficient responses);
- Eligibility to the full five year capex efficiency incentive;
- The assessment of efficiency at reviews.

Given the strength of these incentives it would appear inefficient to place yet another incentive on companies to respond efficiently to severe weather.

The main features of the FE proposed replacement for the severe weather exemption are:

- That uncontrollable payments made under severe weather conditions are to be passed through and recovered from all customers;

- That companies would be exposed to the controllable payments;

- That the breakpoint between controllable and uncontrollable payments would be determined via a rule based process.

The main flaw here is the subjective determination of the breakpoint between uncontrollable and controllable. It would be possible to determine predefined storm reconnection periods, as these would have to allow for differences in storm severity across companies and differing levels of network damage due to regional variations (e.g. proportion of tree cover).

The main benefit ascribed to this approach is that it would reduce the level of uncertainty for companies between the event and Ofgem's decision. In reality, if the pre-defined restoration criteria are inappropriate, the process would be a lottery, with some companies winning and others losing. Ofgem would need to carefully consider how such a result (including a cross subsidy between from urban to rural customers, and an overall increase in customers' bills) would be furthering its statutory objectives.

For those companies who are incorrectly deemed to have failed in responding to the severe weather, in addition to having to pay unwarranted payments to customers they are likely to face reputational damage. This may affect their ability to attract finance to fund future network investment. We do not believe that such an outcome would be Ofgem's intention.

Distributed Generation ("DG") – general comments: we agree that there is a need for different mechanisms to address the short and long term DG issues. We agree that in the long-term DG related expenditure will become a normal part of a distributor's work and can be incorporated into the main price control arrangements. However, in the short term, the very high level of uncertainty requires a bespoke approach.

There appears to be a significant misunderstanding over the reasons why the required volumes of distributed generation (DG) may not be connected. FE suggests that distributors have control over the volumes of generation connected. Indeed, it is suggested that DNOs could cherry pick connection requests to ensure higher returns under a mechanism that sets a standardised unit cost for the connection of DG. As Ofgem will be aware, there are a number of legal requirements that ensure that distributors cannot discriminate against any individual or class of connectee:

- A duty under section 16 of the Electricity Act to connect, irrespective of the type (i.e. demand or generation);

- A general duty under the section 9 of the Electricity Act to facilitate competition in generation; and

- A licence condition requiring non-discrimination.

Failure to comply with any of these requirements can result in the distributor being fined.

We do accept that increased proactivity by DNOs could encourage DG schemes. For example, should a DNO identify a need for DG support, in lieu of reinforcement, it could seek out potential DG connectees and attract them to that location.

Short term DG issues: we agree that there is considerable uncertainty over:

- The volume of DG requiring connection.

- The physical location of the DG; and

- The required reinforcement costs.

Risks for distributors would be increased if there is an expectation that expenditure is required in advance of need. For distributors to attract the funds for this, the risk of non-recovery must be removed. Therefore, any mechanism for dealing with uncertainty associated with DG must allow distributors to:

- Recover their costs in full (including any increased opex); including

- The relevant cost of capital.

This is essential if distributors are to be incentivised to pro-actively encourage the connection of additional DG in their particular service areas. If such a scheme is not developed, they will be reactive to DG. Consequently, there is a risk that the required volumes of DG may not be connected.

Given the very high level of uncertainty over the levels of capital and operating expenditure required to facilitate DG, we do not believe that it should be included within the current RPI-X price control (unless the allowance is large). We accept that the use of other mechanisms such as logging up and interim review may mitigate the volume forecasting risks.

However, if the volume of DG grows significantly, companies may be required to:

- Finance large amounts of unforeseen capex - under a logging up approach, or

- Seek a number of interim reviews.

Both would not significantly reduce the level of uncertainty that distributors are exposed to. Once there is greater certainty over the growth of DG then it would be appropriate for DG related expenditure to be included within the normal price control, with either logging up or interim reviews to deal with large volume/cost fluctuations. In fact this may be a useful interim step in the process of moving to a regime where DG costs are treated no differently than other forms of asset expenditure.

Over the next price control we believe that:

- All DG related costs should be passed through (capital expenditure via the RAV);

- A volume related driver (but not MWh) should be included to provide distributors with an incentive to be proactive in developing DG connection opportunities.

The latter could be set to equal the net present value of the cost of any net reduction in losses hypothecated to a suitable distributed generation capacity driver. This would be one way of overcoming the issues associated with increasing the power of the current losses incentive.

This approach is similar to that outlined by FE in section 4.3.2. We believe that the mechanism should, in the short term, be biased towards incentivising the delivery of outputs. We accept that such an approach could be open to gaming, as the proposed capital efficiency mechanism encourages companies to reduce capital expenditure below the allowed level. In particular, companies could look to substitute load and non-related asset expenditure to maximise their efficiency position. We would welcome the opportunity to work with Ofgem to explore methodologies to mitigate this risk.

LE Group
April 2003

Attachment D

Developing Network Price Controls: Workstream B: Balancing Incentives

Summary: we believe that the work undertaken by Frontier Economics ("FE") has been useful in moving forward the debate on balancing the range of incentives that distribution businesses are exposed to, and we are supporting many of their conclusions. However, we do not agree that:

- Most Capex efficiencies tend to be one-off in nature;
- FE's assessment of the incentive power of yardstick mechanisms is robust;
- Investors can, in practice, diversify away the risks of yardstick competition; and
- Total cost modelling alone can currently deliver robust results.

In order to ensure the delivery of optimum company behaviour we do believe that:

- The efficiency assessment for both capex and opex, at the time of each review, should have equal robustness/incentive properties, and should be informed by an assessment of total costs;
- Efficiency incentives should be increase to 50:50 shared between companies and customers in NPV terms to optimise customer welfare;
- The range of output incentives could be extended to those key outputs valued by customers, for example, outputs relating to worst served customers and asset condition;
- Yardstick regulation could spread inappropriate asset risk (though unsustainably low cost levels/model error) throughout the DNOs unless target cost levels are set at average costs or above (i.e. not frontier levels);
- Double jeopardies inherent in the current incentive framework should be removed wherever appropriate;
- Price control efficiency assessments should take account of quality as well as cost, and the results of the ARM survey; and,
- Opex and capex funding should be set on the basis of fully funding the target levels of outputs/quality. Balanced output and efficiency incentives will ensure that companies do not forego the value of the opex/capex efficiency incentives by pursuing increased outputs.

Incentives in regulation

Incentive power and the treatment of operating and capital expenditure: During the course of a price control period, the cost of carrying out some individual activities may rise, and other costs may fall. Macro level efficiency savings will occur where overall costs are reduced (for a given level of outputs). Both overall opex and capex efficiency savings can occur as a consequence of, carrying out activities at a lower unit cost, delaying activities, or not carrying out activities at all (through a better understanding of asset risk). For both opex and capex, some of these savings will be one-off and some will be recurring. From an incentive perspective it does not matter whether the individual savings are one-off or recurring. It is the overall net effect that is important, and the net effect tends to be recurring.

In any case, we do not agree with FE's unsubstantiated assertion that capex efficiencies tend to be one-off. Such savings are typically made in terms of staff productivity, pay and conditions, use of contractors, improved project management, better prices for plant and materials, reduced stockholding, etc – all of which are recurring. It is therefore not robust for FE to compare the incentive properties of recurring opex and one-off capex efficiencies.

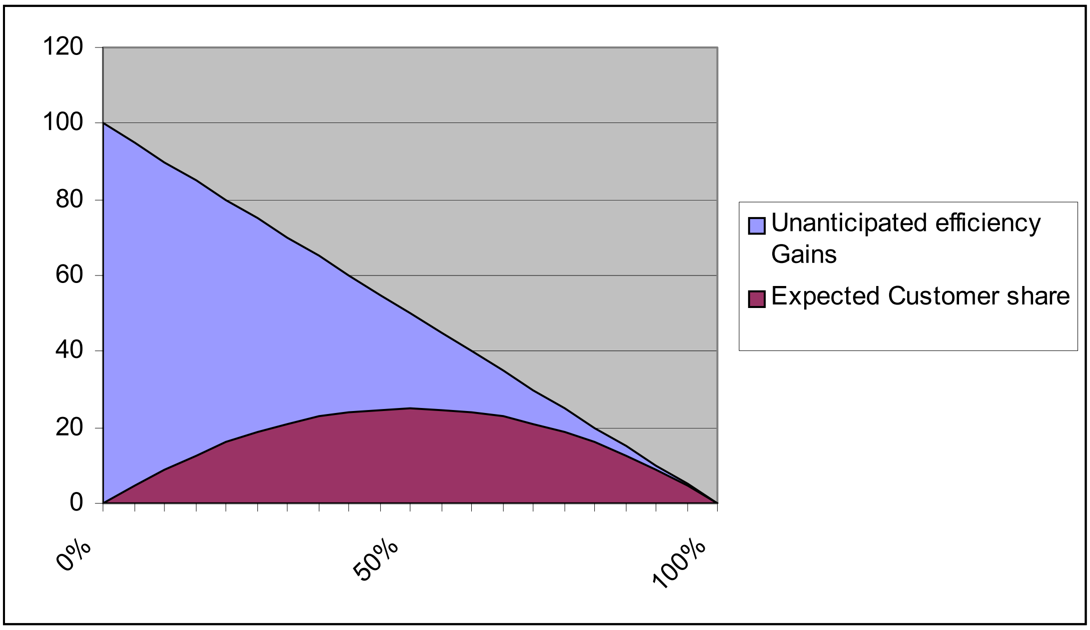
There are clear and material differences in the current incentives applied to opex and capex efficiencies. Where the proportion of any efficiency gain, retained by companies, is different for different types of expenditure, then the regime is likely to produce an inefficient outcome. For example, as opex incentives are greater than capex incentives, companies will deliver a sub-optimal balance between the two. There is also an incentive to inappropriately reclassify opex expenditure as capex to seek the higher opex efficiency incentives compared to the smaller capex efficiency incentive foregone. This problem is made worse by a price control review methodology that focuses more sharply on opex efficiencies compared to capex. The solution to these problems is to:

- Equalise the proportion of efficiency savings retained by the company between reviews; and

- Ensure that the efficiency assessment at the time of each review has equal robustness/incentive properties or uses an assessment of total costs.

Incentive power and the length companies retain benefits: it is possible to compare the strength of one incentive regime to another by calculating the proportion of any unanticipated efficiency saving/gains which the company retains compared to the proportion passed on to customers. In general terms, the greater the proportion retained by the company the greater the strength of the incentive regime, and hence the size of efficiency gains.

As the proportion of efficiency saving retained by the company increases, so does the size of the overall efficiency saving. At the same time, the proportion of the efficiency saving retained by customers decreases. However, the customer's absolute gain will increase with the increasing company proportion before decreasing beyond a certain company retention proportion. Based on an assumed linear relationship between incentives and gains, the optimal share for customers of unanticipated efficiency gains is 50%. This is illustrated in Figure 1 below.



The optimum share is sensitive to the actual trade-off between efficiency and incentives, which may not in practice be linear. However, the existing company retention proportions for recurring expenditure reductions, of approximately 30% for opex and 10% for capex, do not suggest a credible trade-off. This implies that a significant increase in the company retention proportion, especially in the case of capex, is required to maximise future customer gains.

If the existing structure/profile of efficiency incentives is retained, the 50:50 company/customer share is reached if the retention period is around eleven years for opex and fourteen years for capex. However, so long as the NPV of the 50:50 share is maintained, the profile and length of the period over which the company benefits from the incentive is a matter of choice. There is no *a priori* link between the retention period and the period of the price control.

Incentive Power and the length of retention period: as noted earlier, the company/customer share of efficiency savings should be 50:50. This would be a significant increase over the current incentive. However, some, but not all output changes can be observed in the short term. For example, there may be a long lead-time between inefficiently low investment levels and infrastructure failure. More powerful cost efficiency incentives could therefore increase the likelihood/temptation of cutting costs below the sustainable level.

In the absence of being able to measure all outputs without a time lag, the use of ARM to assess efficiency is an important safeguard to customers. It would also be possible to ensure that as the incentive power is increased to the optimum 50/50 level, the period over which the incentive is paid to the company is also increased. This would allow the future level of revealed time-lagged-output, in particular where this was below an acceptable minimum, to trigger enforcement and if necessary withholding part of the future portion of the incentive. This could be an extension of the current principle of the eligibility criteria for the full five-year capex incentives. However, it would only be applied to time-lagged outputs.

Length of the price control: as noted earlier there is no *a priori* link between the retention period and the period of the price control. However, there is some concern that current price controls are not being set on the basis of long-term cost/investment needs of assets. This could be addressed by taking a longer-term view of investment requirements, say fifteen or twenty years to set the investment needs for the current control period. Over time, the price control period could be increased to say ten years and in parallel retain the longer-term view of cost requirements. However, in so doing, appropriate uncertainty mechanisms would need to be in place to protect companies, from unforeseen cost shocks.

Incentive Power and different regulatory arrangements: as noted earlier, it is possible to compare the strength of one incentive regime to another by calculating the proportion of any unanticipated efficiency savings/gains that the company retains compared to the proportion passed to the customer. However, the relationship between the proportion of efficiency savings retained by the company and the resulting overall efficiency gain may not be known. The relationship may not be linear, and even if it was, it is not clear what the slope of the line would be. Therefore, comparisons can only be done in relative, rather than absolute terms, i.e. it is possible to conclude that one regime has greater incentive power than another, but it is not possible to state what the absolute incentive power of the regime is.

Similarly, it is possible to compare the incentive power of cost benchmarking or yardstick competition where there are different numbers of companies in the comparison. That is, the greater the number of companies the greater the incentive power. However, the relationship between the number of companies in the comparison and the level of efficiency is unclear. Consequently, this comparison can only be done in relative rather than absolute terms, i.e. it is possible to conclude that one regime has greater incentive power than another regime but it is not possible to state what the absolute incentive power of the regime is.

As the above comparisons of the strength of incentives are only valid as relative comparisons and then only within each comparison, it is not possible to use them to compare the incentive power of the different measures/regimes. FE's demonstration that purports to show the combined strength of a regime that permits five year retention of efficiency savings with one that sets costs at the average of the costs of 14 companies (which FE asserts results in a 95% incentive power) is misleading. The total incentive power of the regime would require the determination of the:

- Absolute incentive powers of the two component mechanisms (this has not been done for either); and

- Relevant period over which the comparison should be made (for example it might be more appropriate to allow for the fact that costs are moved to the average costs in year five hence discounting the effects of benchmarking/yardstick appropriately).

As the calculation of absolute incentive power is erroneous, there is no evidence to substantiate the conclusion that the proportion of efficiency savings retained by companies does not need to be increased. Instead, as noted earlier, the analysis suggests that the proportion should be increased to 50% for both capex and opex.

Application of yardstick competition: it is right to state that theoretically, benchmarking and yardstick competition can offer incentive benefits to the ultimate advantage of customers. However, there are a number of severe practical problems with its implementation:

A. **Inadequate modelling and/or environmental factors make companies difficult to compare:** it is likely to be very difficult to normalise for all the relevant differences between companies, so that real efficiency differences can be robustly identified. The non-efficiency reasons for cost differences between companies is poorly understood and is exacerbated by the small number (fourteen) of reference companies. In Italy and Germany, where there are significantly greater numbers of distributors, only like companies are compared. For example urban companies are not compared to rural ones. It appears unreasonable to mechanistically compare likely outliers (e.g. London and Scottish Hydro) with other distributors.

B. **Lowest cost and industry wide risk:** as noted elsewhere, ideally an assessment of efficiency should take some account of total costs and outputs. However, it may be impossible for the foreseeable future to measure all outputs without a significant time lag. This needs to be considered in any efficiency modelling. For example, different companies may take differing risk strategies to innovate to achieve greater efficiencies. It is therefore possible for a company to take an inappropriate risk by reducing its costs below an efficient level. At the time of the review this may not be evident because of the possible significant lag between reduced expenditure and infrastructure failure.

   Where a regime is in place that sets future costs by reference to the company's own costs, then the individual company bears the risk of its own failure to meet minimum quality levels. This risk is either via regulatory enforcement or ultimately through insolvency, as a consequence of being unable to meet the increased costs of the historical failure to invest. The failure does not spread to the rest of the industry.

   However, where an illusory efficient company is lowest cost and its costs are used as the yardstick (at DR3 costs were set by reference to level of lowest cost companies) there is the likelihood of setting all companies' revenues at this inappropriate and unsustainably low level.

Whatever the basis of the yardstick, this company's performance would "contaminate" the derived yardstick. The inappropriate use of a yardstick thus has the possibility of spreading the risk of infrastructure failure to all companies.

C. **Financing obligations relate to individual licensees:** FE discusses the application of yardstick competition where the yardstick is set on the basis of average industry performance. In this case, FE states that some companies will make excess returns, while others will make low returns and that this risk can be diversified away by an investor holding the shares of all companies resulting in no overall increase in the industry cost of capital. This is a theoretical assertion whereby the rational investor is able to invest in a significant proportion of distribution companies. We do not consider that this diversification is possible in practice. Further, as FE notes, this type of regime can produce inappropriate management incentives.

Even if diversification was possible, it should be noted that the regulator's statutory objectives to finance licensees' activities apply to individual licensees rather than the overall industry sector. Therefore, the mechanistic application of yardstick competition conflicts with this objective.

FE's report glosses over or omits the difficulty of overcoming these problems. Though we do not believe that it will be possible to sufficiently overcome these problems it might be possible to reduce their risks. A yardstick should not be used mechanistically, but it could be used to inform the future level of efficient costs. We believe that:

- The yardstick should not be set at the company(s) with the lowest cost;
- It should be set no lower than the average of all companies' costs. This reduces chance of spreading systematically infrastructure risk to all companies; and
- Companies should be allowed a period of time to move a proportion of the way towards the yardstick.

The latter would enable Ofgem to comply with its financing obligations to individual licensees, the need for time to implement cost reduction strategies, and account for likely errors in normalisation.

Customer benefits and optimal retention periods: it is right to suggest that the relatively easy pickings following privatisation have now gone and that savings will become increasingly difficult as companies approach the efficiency frontier. This supports the need to increase the power of incentives by increasing the proportion retained by companies to the optimal 50%.

The trade off between cost efficiency and quality of supply: there is a link between costs and quality. In general, improvements to quality of supply can only be achieved through additional expenditure. Conversely, a company could reduce costs by reducing quality. Consequently the future efficient level of costs and company incentives during the period of the price control should be informed by the desirable cost/quality requirements. The assessment of efficiency at the price review and the consequent rewards for efficient companies should be set by reference to cost and quality.

Generic approaches for providing incentives to deliver quality

Marginal rewards: the future efficient level of cost/quality should be informed by reference to customers' willingness to pay. Where there is a societal value that cannot easily be observed via the views of individual customers a judgement will need to be made on the appropriate value.

Future cost/quality could, in theory, be set by reference to the full external cost/value of a particular outcome (the marginal cost/quality curve). To deliver the most efficient outcome, companies should be allowed to choose their own position on this curve. However, in practice, information about the curve is likely to be imperfect. Consequently, it might be desirable to assume a linear relationship around a given point with caps and collars for the upper and lower limits of the desirable cost/quality combinations. Company revenues should therefore be set on the basis of fully funding existing levels of quality. In addition to any rewards, revenues should increase by at least the amount of the marginal unit cost required to deliver the required quality.

In determining the existing levels of quality, and hence the required base expenditure, the effect of a number of issues may need to be considered. For example:

- There is an inherent year on year variability in output performance; and

- In some instances the maintenance of existing levels of quality may require increased expenditure especially when this coincides with an ageing network.

Ensuring minimum levels of quality: with the scheme detailed above, there is no need to link receipt of the full amount of any opex and capex efficiency incentives to the achievement of any particular outcome within the caps and collars. However, there is likely to be need disincentivise companies reducing costs by delivering a quality outcome below a minimum level. This could be achieved via a number of mechanisms:

- Enforcement of existing statutory obligations with regards to efficiency, including the use of fining powers. This would have the advantage of being able to take account of any exceptional circumstances that might have led to the quality failure.

- Licence obligations could be amended to state the minimum required quality level. Quality failure could then lead to enforcement action. The level of any fine could take account of all of the circumstances.

It would be inappropriate to mechanistically reduce revenues to companies below a minimum “collar” level, as this would not be able to take account of all the relevant circumstances of the failure.

Overlap of existing incentives: there are currently a number of mechanisms that incentivise the delivery of quality. These are:

- Overall standards

- Statutory objectives regarding the running of efficient and co-ordinated distribution systems;

- IIP scheme

- Eligibility to the full five year capex efficiency incentives

- The assessment of efficiency and the setting of future cost/quality at each price control.

In many instances there is a large degree of overlap and consequently a significant possibility of double jeopardy for companies. These incentives should be rationalised to ensure no inappropriate overlap.

Conflicts between existing incentives: multiple incentives can drive company behaviour in a number directions at once. For example, there is a conflict between the current losses and capex efficiency incentives, in that the former implies expenditure on increased network capacity margins, whilst the latter discourages such investment.

<u>Balanced benchmarking of operating and capital expenditure</u>

Introduction: as noted earlier, we agree with the problems/perversities identified by Frontier. The solution to these problems is to:

- equalise the proportion of efficiency savings retained by the company between reviews; and

- ensure that the efficiency assessment at the time of each review has equal robustness/incentive properties or is informed by an assessment of total costs.

Ofwat’s approach to cost benchmarking: Ofwat applies different incentives (company retention proportion) to opex and capex efficiency. This inevitably drives different behaviour in relation to the two sets of costs. This may be only somewhat lessened by the use of a combined assessment of opex and capex efficiency and use of benchmarking.

The FE report does not explain in any detail how the Ofwat bands for opex and capex efficiency are determined, i.e. what criteria of performance would qualify a company for a particular band. Consequently it is difficult to comment in detail on the appropriateness of the methodology. However, the

Ofwat mechanism appears to have some advantages over the approach undertaken by Ofgem at DPCR3. That is, it is an assessment of efficiency that appears to:

- Be broadly as robust as that carried out for opex (there was an opaque capex assessment at DR3);
- Apply broadly similar incentives for opex and capex (at DR3 there was a negligible capex efficiency incentive though opex frontier companies were significantly rewarded with a flat opex glide-path); and
- Make some attempt to take account of opex and capex tradeoffs (at DR3 there was no evidence of this).

However, excluding capital enhancement from this combined efficiency assessment weakens the efficiency of the regime.

Even if the distortions identified by FE are correct, it is not possible to comment on them without understanding the detailed Ofwat methodology. Further, it is not possible to assess whether these distortions are as severe as the problems with the Ofgem DR3 methodology. However, if it is not possible to produce an appropriate measure of total costs, then some form of this scheme should be considered, ideally using a combined assessment of opex and capex (both replacement and enhancement).

Total cost regulation

Introduction: as noted earlier, the use of total costs could reduce some of the existing inefficiencies of the regime. However, as it is likely that the existing RPI-X mechanism is also to be retained, then the existing differential company incentive retention proportions, for different types of efficiency, would also need to be equalised. Ideally, this methodology would be extended to some combined assessment of total cost and quality.

In addition to the issues stated in the report, it should be noted that the prevailing value of assets is also affected by the different depreciation rates between companies.

Cash cost approach: a crude assessment of capex efficiency could be to use capex expenditure in the base year, as for opex at DR3. However, this might provide a misleading assessment of efficiency because:

- Assets are long lived and on the basis of current expenditure levels, the capex in any one-year adds to or replaces only a very small proportion of the total asset base;
- The expenditure incurred this year will, to a certain extent, effect expenditure requirements for the following years; and
- Due to the nature of investment cycles, capex expenditure can also vary greatly from year to year.

Capex efficiency thus depends on the levels of expenditure over a much longer period of time than a single year. In principle, all expenditure on the current asset base, however long ago it was undertaken and even where it has been fully depreciated, will have some impact on the expenditure requirements next year. In general terms, last year's expenditure could be a better guide to next year's expenditure requirements than expenditure carried out say twenty years ago. However, it is unclear how the influence of older assets and hence older expenditure should be taken account of. The current value of the regulatory asset base mimics this in crude terms. That is, older assets have a zero value in the RAV, as they will have been full depreciated. However, this value is distorted by the valuation of assets at privatisation and the differing depreciation rates applied to assets both within and between companies' asset bases.

If an assessment of capex efficiency needs to take account of expenditure over many years then some consideration needs to be given to the possible effects on the levels of capex of opex/capex substitution possibilities, i.e. a company will at any time decide whether the optimum solution to a given output is to expend either opex or capex. This raises a number of questions.

- Is substitution material?
- Is it appropriate to use one year of opex expenditure and many years of capex expenditure or should the period of assessment be the same for all forms of expenditure?
- If different assessment periods are used should some adjustment be made to the results to reflect the substitution possibilities?

Many of the arguments made earlier in this section in relation to capex applies to opex. Though the quantum of opex from one year to the next is not as variable as capex, looking at a single year's data might not be applicable. For example, expenditure incurred in response to severe weather disruption of the network, because of the introduction of new IT systems or as the consequence of a merger or any other major reorganisation of a company could make one year's opex misrepresentative.

Capital stock models: revaluation could address some of the concerns highlighted above in relation to capex. However, it is not clear what the appropriate starting valuation and the appropriate period and rate of depreciation should be. Different assets will have a different effect on expenditure over time and a different useful life.

The level of available asset information, especially for older assets, is likely to vary between companies. In many instances there may be little or no information on the oldest assets.

Regulatory choices and the drivers of total cost efficiency

Introduction: the use of the three categories, inherited, inherent and incurred costs is a useful way of looking at the network and companies' ability to affect changes to costs over time.

Inherited costs: companies cannot fully control these costs in the short run. In the long run as inherited assets reach the end of their useful life, companies will have more control over the costs of the assets employed to replace them. The range of possible outcomes is:

- A - As individual components of the inherited asset base come to the end of their useful life they are replaced like for like with equivalent assets. The costs of that asset replacement are thus partly controllable by the company. However, because the company has to retain the design of the inherited network, a permanent wedge between the level of costs (and quality) of different companies is maintained; or

- B - As individual components of the inherited asset base come to the end of their useful life they are replaced with assets required to implement the new network design. However, this network design is constrained (as is costs and quality of replacement assets) by the inherited network design. However, in achieving this enhanced design both the costs (and quality) are to a greater extent controllable by the company. However, because the company is constrained in its choice of network design, a permanent but reduced wedge between the level of costs and quality of different companies is maintained; or

- C - As the overall asset base comes to the end of its useful life it is entirely replaced with assets required to implement a new network design, which is unconstrained by the inherited network design. The costs of the asset replacement are controllable by the company. Consequently, in the longer term there should be no differences between the costs (and quality) of different networks.

Subject to the views expressed below about inherent and incurred costs, options A and C (FE's conclusion) are not likely. Option A is unlikely, as assets do not have to be replaced like for like. Companies have at least some ability to affect the costs (and quality) of the network over time relative to other companies through their choices. However, it is far from clear that option C is likely or possible. At current levels of asset replacement, some form of option B is likely to be the inevitable outcome. This can be illustrated with the simple analogy described below.

If a company inherits a broom and the company's replacement/enhancement expenditure each year is very low compared to the total broom replacement cost then the company can only replace individual components. Thus, the company may procure a better/cheaper broom over time but it will never have built a Hoover (even if customers are willing to pay for one).

This implies that inherited costs will need to be taken account of in any determination of total costs, and that the effects will reduce over time - though the effects will not fall to zero unless asset replacement expenditure is sufficiently increased. It is therefore wrong for FE to assert that the inherited network will not continue to influence costs in perpetuity.

Inherent costs: we agree that there might be a permanent wedge between the costs of different companies.

Incurred costs: we agree that:

- Subject to the uncontrollable inherited and inherent costs that these are to some extent controllable by management going forward. However, past management choices will have been strongly influenced by the subsisting regulatory framework.

- There is the need to allow for valid differences between companies regarding control for inherited and inherent costs; and

- Any assessment of past efficiency or future required levels of efficient expenditure needs to normalise for inherited and inherent costs, rather than exclude any categories of assets.

Valuation of assets: it is far from clear:

- What the appropriate valuation of assets should be.

- How these valuations should change over time.

- Whether different profiles should be used for different asset types; and

- How these should be normalised for inherent and incurred costs.

We believe that the scheme chosen should balance the need for, simplicity, accuracy, materiality of the particular issues, cost of implementation, and the availability of data.

Adjustments for inherent network factors: it is far from clear how to adjust for all the relevant factors. The composite customer variable (plus regional cost factor adjustment) used at DPR3 for the opex regressions was crude.

Relevance of the RAB under total cost benchmarking: implementation of any future stream of revenues will need to ensure that the existing value of the RAV is not impaired where any implied future level of efficient costs is lower than the costs of funding the historically incurred capex. That is, future additional expenditure rather than prices should be targeted. Not to roll forward the value of the RAV and adequately fund it would be contrary to the principles of incentive regulation whereby changes are not made retrospectively. This aligns with the various pronouncements of the Competition Commission (previously MMC) and Ofgem's past commitments.

Periodicity

Introduction: we agree that the adoption of rolling adjustment mechanisms should be introduced to eliminate periodicity. The Ofwat mechanism forms a suitable basis for such a mechanism. However, there are a number of features of the Ofwat model that we do not believe would be appropriate to replicate with regard to electricity distribution. These are:

- The treatment of exceptional costs; and
- The methodology for assessing the incremental out-performance in the final year of the price control.

These are discussed in more detail below:

The treatment of exceptional costs: in Ofwat's model, exceptional costs are included in the calculation of incremental out-performance. Such an approach is only correct if there is an appropriate regulatory allowance to cover the manifestation of the particular uncertainties. However, if an unforeseen event occurs, for which there is no regulatory allowance, then these costs should not be included within the calculation. If these costs are not excluded (i.e. they remain within the ambit of the rolling mechanism) there is a risk that the incentive allowance in the next period will be reduced or completely negated. An example of this is shown in Appendix 1. This demonstrates that if a company incurs an exceptional loss in 2003/04 it loses all of its incentive allowance for the next period (2005/06 – 2009/10).

This loss in the penultimate year is further compounded by the treatment of the incremental out-performance in the final year of the price control. Due to the impact of the exceptional event, the company is incorrectly assumed to have made a large efficiency saving in the final year of the control. It is assumed to keep this efficiency saving throughout the next review period. Under the Ofwat model this saving is then deducted from the incentive allowance of the first year of the subsequent price control (2010/11 to 2014/15). In this example, the inclusion of the exceptional event negates the incentive allowance in the first year of the 2010/11 to 2014/15 price control.

The methodology for assessing the incremental out-performance in the final year of the price control: in the Ofwat model, no incremental out-performance is forecast to occur in the final year of the price control. Any actual out-performance in the last year of the control will also be repeated for each of the five years of the next control period – making six years savings retained. This additional year's retention will be recovered by adjusting the incentive allowance in the first year of the subsequent review.

We believe that Ofgem should use an estimate of companies' performance in the last year of the price control to calculate the incentive payments over the next price control period. This approach is likely to require smaller adjustments and hence have a less significant impact on prices to customers.

Capital Efficiency mechanism: we support the FE view that companies should be able to retain both the cost of capital and depreciation associated with any capital efficiency saving.

The capital efficiency incentive is based on comparisons between actual and forecast net capex. Therefore, it is important that suitable adjustment mechanisms are established to take into account the impact of all unforeseen events on capital expenditure. In particular, capital expenditure in relation to the growth of distributed generation is likely to be difficult to predict. Without such mechanisms, the incentives to connect distributed generation will be undermined, if the associated expenditure needs to be higher than forecast.

Calculation of incentive floors: As noted elsewhere in this response, the NPV share of any unforeseen permanent cost reductions retained by a company (as opposed to a customer) is lower for capex (10%) than opex (30%), i.e. opex incentives are greater than capex incentives. To generate £1m of capital efficiency gains a company must save significantly more than £1m of capital expenditure. However, all of this saving would be negated by an opex overspend of £1m.

An aggregation of operating and capital efficiency overspends/efficiencies places undue weight on operating expenditure, and would increase the incentives on companies to capitalise opex. Until such time as incentives between opex and capex are equalised, any mechanistic aggregation of operating expenditure overspends/efficiencies will produce erroneous results and is likely to increase the current opex/capex perversities.

For the current price control period, the five-year opex and capex incentive mechanisms should be operated separately. Opex/capex tradeoffs can be taken account of at the time of the next price control, possibly informed by an assessment of total cost efficiency. In the longer term, the issue would be resolved by:

- equalising the NPV proportion of efficiency savings retained by the company between reviews and aggregate the effect of the two mechanisms; and

- ensuring that the efficiency assessment at the time of each review is informed by an assessment of total costs.

<u>Regulating cost and quality</u>

Introduction: as noted earlier, efficiency assessments should ideally take account of cost and quality. The comments earlier, relating to yardsticks and inadequate modelling and/or environmental factors making companies incomparable, are also relevant here, as well as issues overlapping with those relating to the assessment of capex efficiency (also noted above). Much further work is required before quality can be robustly compared between companies. Until such time, it might be more appropriate to use the quality assessment in a non-mechanistic way to inform efficiency assessment.

Including quality in a two-stage efficiency analysis: there is merit in giving further consideration to the approach described by FE. However, it would be appropriate to use a number of models in the analysis to check for consistency of results.

Exogenous operational modelling: we do not support use of a reference network. Any such network is unlikely to be representative of reality. Indeed, it is unlikely that it could be robustly created in practice because of the difficulty in fully understanding all of the relevant inter-relationships between costs and outputs.

Rewarding frontier performance: As in other assessments of efficiency, frontier performance should be adequately rewarded.

Setting a target level for quality of supply in marginal payment schemes: please see our response to section 2.6 above.

ARM survey: it is correct to state that achieving a maximum score in all categories does not necessarily imply efficient behaviour. However, the ARM results should be used to inform any overall assessment of total cost and quality efficiency. In particular, it can be used to gain confidence in the medium term performance of the network, and in our investment submissions.

London Electricity

April 2003

Appendix 1: Impact of large exceptional cost on future opex incentive allowance

Base Model															
	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Allowed Opex	110	106	104	100.0	99.0	97.0	96.0	95.0	94.0	93.0	90.2	87.5	84.9	82.3	79.9
Actual Opex	109	104	101	97.0	96.0	94.0	88.0	84.0	79.0	78.0					
Difference	1.0	2.0	3.0	3.0	3.0	3.0	8.0	11.0	15.0	15.0					
Incremental outperformance	1.0	1.0	1.0	0.0	0.0	3.0	5.0	3.0	4.0	0.0					
Incentive Allowance						2.0	1.0	0.0	0.0	0.0	12.0	7.0	4.0	0.0	0.0
Actual Incentive Allowance						2.0	1.0	0.0	0.0	0.0	12.0	7.0	4.0	0.0	0.0
Total add allowance for period										3.0					23.0

Large exceptional cost in 2003/04															
	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Allowed Opex	110	106	104	100.0	99.0	97.0	96.0	95.0	94.0	93.0	90.2	87.5	84.9	82.3	79.9
Actual Opex	109	104	101	109.0	96.0	94.0	88.0	84.0	79.0	78.0					
Difference	1.0	2.0	3.0	-9.0	3.0	3.0	8.0	11.0	15.0	15.0					
Incremental outperformance	1.0	1.0	1.0	-12.0	0.0	3.0	5.0	3.0	4.0	0.0					
Incentive Allowance						-10.0	-11.0	-12.0	0.0	0.0	0.0	7.0	4.0	0.0	0.0
Actual Incentive Allowance						0.0	0.0	0.0	0.0	0.0	0.0	7.0	4.0	0.0	0.0
Total add allowance for period										0.0					11.0