CE Electric UK

Your ref

Our ref

Lloyds Court
78 Grey Street
Newcastle upon Tyne
NE1 6AF
tel (0191) 223 5115
fax (0191) 223 5132
e-mail:john.france@ce-electricuk.com

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

5 May 2004

Dear Nienke,

**ELECTRICITY DISTRIBUTION PRICE CONTROL REVIEW:
POLICY DOCUMENT – MARCH 2004**

CE Electric UK Funding Company (CE) is the UK parent company of Northern Electric Distribution Limited (NEDL) and Yorkshire Electricity Distribution plc (YEDL). The views expressed represent the response of CE, NEDL and YEDL to Ofgem's publication, '*Electricity Distribution Price Control Review: Policy Document, March 2004'* (the *Policy Document)*. We are grateful for having the opportunity to comment on this latest update to Ofgem's thinking on the policy issues.

Overall we believe that the *Policy Document* represents a significant development in Ofgem's work towards publishing initial proposals for network monopoly price controls to be effective from 1 April 2005. In summary, our key concerns are:

- **Cost of capital** - we urge Ofgem to re-consider the evidence to arrive at a range of bands and then select a cost of capital at the upper end to reflect the strong investment focus of this review.

- **Pensions** - our concerns relate to the allocation between price-controlled and non-price controlled activities, the treatment of over- or under-provision and the treatment of ERDCs. The last of these is the most material issue.

- **Categorisation of costs and incentives -** we have proposed an alternative approach which equalises incentives as far as possible without the significant dilution of incentives and resultant implications for the regulatory framework inherent in Ofgem's proposal.

- **Incentives for investment -** we have made some suggestions which we believe address Ofgem's concerns and would encourage the desired DNO behaviour. We strongly oppose the blanket reduction in incentives that would arise from the retention of the rate of return element only of efficiently avoided expenditure.

- **Benchmarking** – confidence that the normalisation process and CSV variables are robust is difficult to achieve and is insufficient to justify any benchmark other than the average (i.e. ordinary least squares (OLS)) regression line.

- **Determination of allowances** - future capex allowances must recognise a degree of capitalisation that is consistent for all companies. Future opex allowances must ensure all relevant efficient costs are added back to the normalised cost allowance.

- **Treatment of uncertain costs** - we support the mechanism and the form of the associated proposed draft licence amendments described in the letter, dated 15 April 2004, to David Gray from the Energy Networks Association.

- **Mergers** – we believe that it will not be necessary to adjust DNOs' costs for merger savings for the purpose of benchmarking; nor is it necessary to make any further adjustments to merged companies' allowances to be consistent with the Ofgem merger policy prevailing at the time of the merger between NEDL and YEDL.

- **Distributed Generation** - the current proposals amount only to a funding mechanism, and do not really provide an incentive. We believe that a higher revenue driver is required: we see this as vital if distributors' behaviour is to be changed.

We note that more detailed proposals have not yet been developed in a number of significant areas including the parameters for the information and incentives scheme and proposals for the separate metering price control. We will provide our views on these issues in due course.

We remain committed to working with Ofgem with the aim of resolving the issues we have outlined. We are grateful for the opportunities that Ofgem has afforded us to date to discuss these in more detail and look forward to a continued dialogue with Ofgem as we reach the most critical point in the review process.

Yours sincerely

John France

Director of Regulation

ELECTRICITY DISTRIBUTION PRICE CONTROL REVIEW:
POLICY DOCUMENT – MARCH 2004

The response from CE Electric UK Funding Company (CE), Northern Electric Distribution Ltd (NEDL) and Yorkshire Electricity Distribution plc (YEDL)

ELECTRICITY DISTRIBUTION PRICE CONTROL:
Policy Document – March 2004

The response from CE Electric UK Funding Company (CE), Northern Electric Distribution Ltd (NEDL) and Yorkshire Electricity Distribution plc (YEDL).

The views of CE, NEDL and YEDL in response to Ofgem's publication *Electricity Distribution Price Control: Policy Document, March 2004* are set out below. The response broadly follows the form of the March *Policy Document* and is provided as an executive summary followed by a point-by-point discussion.

EXECUTIVE SUMMARY

Form, structure and scope of price controls

- ***Price index:*** If Ofgem were to consider changing the RPI – X regulatory framework to CPI – X, it would be necessary to also change the X factor and other factors of the price control to maintain consistency and to ensure that DNOs are not adversely affected by the transition. This is because the estimated level of differential total factor productivity (TFP) growth between the electricity distribution sector and the wider economy would also be materially affected by a change to the CPI. We believe that it would require considerable effort to re-estimate the other related parameters of the price control, and that it would require a longer period than available in the current price control timetable to consider this issue properly. We therefore believe that, as has been decided by Ofwat, it would be appropriate to consider this issue after DPCR4. This would give time for all regulators to jointly work on the implications of such a change.
- ***Exit charges and wheeled units:*** We agree with the decision to treat NGC exit charges and wheeled units as pass-through costs.
- ***Business rates:*** We continue to believe that business rates do not constitute a controllable cost under the price control regime and should therefore be a pass-through cost.
- ***Dealing with uncertainty:*** We propose that a formal mechanism is required to ring-fence certain activities / obligations which are known will materialise but in respect of which the forecast costs are uncertain and to cater for the addition of new but as yet unknown obligations that may materialise due to changes of law. We support the mechanism and

the form of the associated proposed draft licence amendments described in the letter, dated 15 April 2004, to David Gray from the Energy Networks Association.

- ***Retention periods for efficiency savings:*** as part of our response to Ofgem's December 2003 *Update* consultation, we submitted a paper that provided theoretical justification for retention periods longer than those being proposed by Ofgem. We are disappointed that the March *Policy Document* does not set out Ofgem's rationale for now concluding that there is no evidence that the existing incentives need to be strengthened.
- ***Definition of costs and incentives:*** We share Ofgem's concerns that categorisation of costs as opex and capex varies substantially across DNOs and support, in principle, equalising incentives, as far as possible. However, the results of Ofgem's proposals would be a very much-diluted set of incentives on cost performance that will impact on the rates of return that can be achieved by DNOs in future. We have proposed an alternative approach that would meet Ofgem's objectives of equalising incentives as far as possible but which would not lead to the dilution of opex incentives that would otherwise prevail.
- ***Incentives for investment deferral and treatment of capex overspends:*** We are providing, in a separate paper to Martin Crouch, some suggestions as to the best way to meet Ofgem's concerns regarding incentives for investment deferral, and the treatment of capex overspends. The challenge for DPCR4 is to set capital allowances on a comparable basis and to reward companies fairly and equally in relation to the out-performance or under-performance of their respective allowances.

  Complexity arises from the significant challenge in wanting both to encourage and discourage investment simultaneously, i.e. to ensure that enough investment is made to secure the health of the system while also ensuring that both volumes and unit costs are managed effectively to restrain price increases.

  Given the broad acceptance across the industry of the need for a general increase in investment, the appropriate course should not be to weaken incentives to invest at the very time where investment levels look set to increase and when future efficiencies will prove much more difficult to capture than those previously released, largely through de-manning. The incentive regime should:

  - ensure that the right investments are made;
  - encourage realistic forecasts to be submitted; and
  - discourage inefficient investment.

We believe that it is possible to achieve these outcomes at DPCR4.

- ***Rolling opex incentive:*** We generally support Ofgem's proposals for the operating cost rolling adjustment. However, we believe that exceptional / atypical items should be excluded and we continue to disagree with the proposal to link the incentive to some form of eligibility test as there are other schemes and measures in place, for example IIP, that carry penalty for failure. A further test would introduce double jeopardy.

- ***Rolling capex incentive:*** We continue to support strongly the retention of both the depreciation and return benefits and agree that the commitment is conditional on companies meeting their security and supply obligations – upon which Ofgem will take a general view of companies' compliance. We think that the depreciation benefits should continue to be available for efficiencies in the next price control period under certain circumstances.

  It may be difficult to identify efficiency savings in respect of meters separately as meter-related capex was not a separately identified element of Ofgem's capex allowance at DPCR3.

- ***Losses incentive:*** Whilst we are supportive of the proposed simplification of the losses incentive mechanism and the methodology proposed to support it, we have some concerns over its implications. We believe that the most appropriate channel for addressing these issues, and the transitional arrangements that may be required, will be through the forthcoming consultation on the implementation of the new losses regime and we shall make our detailed response on these issues there.

- ***Metering price control:*** We are broadly content with the process on developing the separate metering price control, particularly since the establishment of the joint Ofgem / DNO metering working group, and we believe that there is potentially a straightforward route to implementing a metering price control for meter operation services for outsourced service providers. We shall continue to work actively with the Ofgem / DNO metering working group to develop these proposals further.

Quality of service and other outputs

- We support many of the proposals relating to quality of service in the March *Policy Document* and accept that the Ofgem / DNO working group is making good progress on developing the detail. The key issues to resolve are the trigger levels, band sizes and level of funding for the proposed severe weather standard, the setting of IIP targets and incentive rates for the next price control period and the definition of frontier performance.

We do not agree with the proposal to reduce the weighting for planned interruptions under IIP. Ofgem also need to recognise the sensitivity of the multiple interruption guaranteed standard before considering any changes in the target levels; a very small change will give a very big increase in failures or require significant expenditure to mitigate.

Distributed generation

- Although we welcome the introduction of the new mechanisms to help to facilitate DG connections, particularly the RPZ concept, the current proposals amount only to a funding mechanism and do not really provide an incentive. We do not seek yet further safeguards, as might be given by increasing the pass-through proportion, but do strongly believe that a higher revenue driver is required: we see this as vital if distributors' behaviour is to be changed.

Assessing costs

- ***Lowest cost is not necessarily best:*** Regardless of the method of assessment it is important that NEDL and YEDL are allowed their efficient costs after taking into account the outputs that each DNO delivers. Other performance aspects must be considered, in addition to cost, when assessing efficiency.
- ***Benchmarking techniques:*** If regression is to be used as part of the cost assessment process, we consider an OLS (or average) approach to be the most appropriate technique, taking into account the potential errors in the normalisation process and the determination of the composite scale variable (CSV). An OLS approach would also be better for incentives by allowing the lower cost companies to enjoy the benefits of efficiency savings for longer. Care must be taken to ensure that the data used is accurate and from audited sources where possible. Whilst we believe that the normalisation process has come a long way, we are not confident that the results of that or the accuracy and consistency of certain elements of the CSV data can ever justify a benchmark other than the average.
- ***Future efficiency expectations:*** There is no compelling case for regulators attempting to anticipate future efficiencies by applying an ongoing improvement expectation to any derived benchmark, particularly as future efficiency savings are proving harder to achieve. The incentive properties of RPI-X regulation will bring forward any efficiency projects that yield a positive NPV. Companies should not be expected to pass the benefits from these savings onto customers before the savings have been made. The

significant rate of TFP gains achieved during the period since privatisation is not an indication of future likely trends. The RPI captures the productivity gains of the UK economy and to consider a benchmark shift when setting the price control assumes that DNOs can continue to significantly improve upon the efficiency gains in the economy as whole. This is clearly not credible.

- ***Mergers:*** With regard to Ofgem's policy on the treatment of mergers, the *Policy Document* states that it may not be necessary to adjust DNOs' costs for merger savings for the purpose of benchmarking. We agree with this thinking.
- ***Treatment of overheads:*** It is essential that future capex allowances recognise a degree of overhead capitalisation that is consistent with the Ofgem assumptions for the regression used as the basis for the determination of allowed revenues.
- ***RAV roll-forward:*** We believe that NEDL and YEDL should be treated equitably compared with other DNOs. Our letter of 19 November 2003 to Carl Hetherington on the treatment of fault costs provides further details of what we believe is an appropriate adjustment for NEDL and YEDL. The RAV roll forward should not penalise NEDL and YEDL for having capitalised less in the past.

Financial issues

Pensions

- Our concerns with regard to pensions relate to the allocation between price-controlled and non-price controlled activities, the treatment of over- or under-provision and the treatment of early retirement deficiency costs (ERDCs). The last of these is the most material issue.
- We strongly disagree with Ofgem's conclusion that adjustments reflecting the use of surplus to fund ERDCs are necessary before the share of the deficit to be borne by distribution customers is determined. We believe that Ofgem's underlying reasoning for this proposed treatment, as set out in the March *Policy Document*, is inconsistent with some previous Ofgem reasoning, and is inconsistent with the basis on which all previous RPI-X price control reviews of have been conducted.

Cost of capital

- We welcome Ofgem's approach to adopting a consistent method for setting the allowed cost of capital, in terms of utilising the capital asset pricing model (CAPM) and also the transparency of the evidence considered in arriving at the key parameters.

- However, as we indicated in our response to Ofgem's December Second Consultation, the recent work that NERA has conducted for both the water industry[1] and EDF[2] indicates that the CAPM model should not be biased by short-term market conditions on specific components such as beta and debt premia. This work also draws on international benchmarks and suggests cross-checks to other methods should be utilised since CAPM is recognised as under-estimating the true cost of capital.
- This requirement to recognise European utility returns was also made by the analyst at the recent Ofgem workshop.[3]
- The NERA report for EDF was submitted in response to Ofgem's December *Second Consultation.* NERA has also recently updated its report for the water industry and we understand this has been submitted to Ofgem. Both of these reports suggest a higher cost of capital than Ofgem's upper band and do not support the proposed lower bands.
- This is further supported by comparison to Ofwat's view that the bottom of its range will be 5.0 per cent on a fully post-tax basis, which is the top of the Ofgem range. This discrepancy is not explained by the different risk profile of the electricity distribution business.
- We would, therefore, urge Ofgem to re-consider the evidence to arrive at a range of bands and then select a cost of capital at the upper end to 'reflect the strong investments focus of this review', which may have resultant issuance costs.
- We would also remind Ofgem that we submitted a paper in December 2003[4] on embedded debt and maintain that the debt incurred by NEDL and YEDL was efficiently incurred and should be allowed in the cost of capital.

Financial modelling and indicators

- We believe that there are still some significant unresolved issues with respect to the financial model. These need to be addressed at the detailed level in order that we can have confidence that the model's outputs can be used to inform the debate on financing. We have submitted our views and these are included in an appendix to this response.
- We continue to oppose the use of accelerated depreciation as a means of addressing any cash flow issues that may arise in the next review period. The allowed income should allow debt and equity holders to receive the appropriate cash flow during the

[1] NERA – UK water cost of capital - A final report for UK water – March 2004
[2] NERA – A Report for EDF energy – March 2004
[3] Ofgem public workshop – 20 March 2004

period without deferral. If cash flows are inadequate to achieve this result then the overall level of return needs to increase. Whilst accelerating depreciation generates additional cash flow it does not address the underlying issue.

Timetable and consultation process

- We welcome the process that Ofgem has established to publish and discuss initial views on benchmarking and capital and operating cost allowances with companies in parallel with the publication of the public consultation documents and ask only that Ofgem continues to aim where possible to allow companies at least a week to review Ofgem's letters before the dates of meetings to discuss the proposals, and that the release dates be published in advance so that we can plan appropriately for their receipt and analysis.
- The work undertaken by Ernst & Young will be published towards the end of May following our review of the outputs and conclusions. Again, we would appreciate it if Ofgem could release this information at least a week before the meeting with Ernst & Young.
- We note that the *Initial Proposals* document is due to be published at the end of June but that the results of the customer willingness to pay survey will not be available until the end of May at the earliest. We would therefore welcome clarity on the process by which Ofgem intends to factor quality, resilience and other output requirements into the allowances to be published in the *Initial Proposals Document*.

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[4] CE Electric and Barclays UK report submitted 9 December 2003

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ELECTRICITY DISTRIBUTION PRICE CONTROL:
Policy document – March 2004

The response from CE Electric UK Funding Company (CE), Northern Electric Distribution Ltd (NEDL) and Yorkshire Electricity Distribution plc (YEDL).

The views of CE, NEDL and YEDL in response to Ofgem's publication *Electricity Distribution Price Control: Policy Document, March 2004* are set out below. The response broadly follows the form of the March *Policy Document*.

1. FORM, STRUCTURE AND SCOPE OF THE PRICE CONTROL (Chapter 3)

1.1 Revenue drivers

(Paragraphs 3.6 to 3.12)

1. We support the decision to retain the 50:50 split between customer numbers and units distributed, in the absence of any alternative proposals, and to use the same customer numbers definition as for IIP. We await Ofgem's analysis regarding the weighting within voltage categories.

1.2 Price index

(Paragraphs 3.13 to 3.14)

2. Replacing RPI with CPI for price control purposes, all other things being equal, would have a very significant impact on future price control income streams and cashflow. Before such a change is made the parties need to have a full understanding of the nature of the change and its effect on the overall economic package of a price control review.

3. If Ofgem were to consider changing the RPI – X regulatory framework to CPI – X, it would be necessary to also change the X factor and other elements of the price control to maintain consistency and to ensure that DNOs are not adversely affected by the transition. This is because the estimated level of differential total factor productivity (TFP) growth between the electricity distribution sector and the wider economy would also be materially affected by a change to the CPI. We believe that it would require considerable effort to re-estimate the other related parameters of the price control, and that this would require a longer period than available in the current price control timetable to consider this issue properly. We therefore believe that, as has been decided by Ofwat, that it would be appropriate to consider this issue after DPCR4.

4. The RPI data will continue to be published and pensions, benefits and index-linked gilts will continue to be calculated on this basis. Thus RPI data will continue to be available in future for regulatory purposes. The continued use of RPI for pensions and benefits also recognises that salary costs are more closely aligned to RPI than to CPI.

5. A detailed regulatory impact assessment should be carried out before any changes are made. This should take into account all of the impacts on the cashflow model (including RAV), the indexation of outputs of the price control model and the algebra contained in the price control formula.

6. The RPI-X model is used by all the regulators in the UK and is long established and well understood. Any radical change would need to be clearly justified in light of the operation of the framework to date and the need to avoid unnecessary changes that would contribute to regulatory uncertainty. This may be a cross-industry issue that would benefit from formal consideration by the Regulators' Joint Working Group.

1.3 NGC exit charges

(Paragraphs 3.16 to 3.20)

7. We agree with the decision to continue to treat NGC exit charges as a pass-through cost. As stated in the March *Policy Document* it is appropriate that NGC is incentivised by its own price control regime.

1.4 Wheeled units

(Paragraphs 3.21 to 3.25)

8. We agree with the proposal to allow the pass-through of the costs associated with wheeling charges and to include the revenues associated with wheeled units within the price control. As we have discussed in detail a number of times before, costs incurred from interconnections with other DNOs were not properly recognised in the last distribution price control review and this proposal now recognises the anomaly whereby DNOs that incur wheeling services costs currently do not receive a cost allowance.

1.5 EHV charges

(Paragraphs 3.26 to 3.32)

9. The proposal is to include EHV charges within the scope of the price control and that charges for new EHV connections made during the next price control period should be treated as excluded service revenue until the next review in 2010, when Ofgem would expect them to be included within the price control.

10. We agree with the proposals and believe that there are at least two main routes that could be taken to incorporate EHV charges within the price control. The first of these is to create a revenue driver for EHV units in line with the other voltage categories; the second is to, in effect, take the forecasts of EHV income and to add them to the PUM calculation.

11. Introducing a new revenue driver would have the benefit of consistency of approach with other voltage categories. However, as we have stated before, we believe that having the same revenue driver (i.e. 50:50 units and customers) would not be appropriate for EHV customers as these costs are driven by capacity and not by units distributed. If this approach is adopted consideration will therefore have to be given to the development of an appropriate revenue driver.

12. A simpler approach, perhaps appropriate only during the transition period of the next price control period, may be to incorporate companies' forecasts (provided these are reasonable) of EHV charges into the price control by adding the revenues to the PUM calculation. As is being discussed in the 'review of electricity distribution charges implementation steering group' (ISG), companies will be expected to move towards the implementation of a long-run incremental cost model during the course of the next review period. Once this is implemented on a consistent basis across all DNOs, the apportionment of costs applicable to all voltage categories, including EHV, will be much clearer. This could facilitate the construction of appropriate tariff baskets for the next price control period and beyond.

1.6 Non-contestable connection charges

(Paragraphs 3.33 to 3.40)

13. We agree with the policy decisions / proposals relating to non-contestable connections, namely:

- no change to the price control treatment of connection charges in respect of reinforcement for demand consumers for this price control period;
- DNOs to be required to publish a clear schedule of charges; and
- the *voluntary* standards of performance to be extended to include all new connections, not just housing estates, and for these not to have financial penalties attached.

14. With regard to the latter point, we do not believe that a range of additional guaranteed service standards is required to support competition in connections. There are many different types and sizes of connection that are successfully controlled under section 16 of the Electricity Act 1989, with only a small number of standards covering specific activities. Performance indicators may be appropriate for the provision of points of connection and design approval for standard low voltage new connections to existing low voltage mains. This would be broadly consistent with some of the current standards applicable to section 16 work.

1.7 Other excluded services

(Paragraphs 3.41 to 3.43)

15. The proposals are for no changes to the arrangements for top-up and standby charges, non-trading rechargeable costs and other minor activities and charges; and for the treatment of units distributed to networks embedded within the DNO to be included within the scope of the price control. The treatment of metering excluded activities will be published in June 2004.

16. We believe that these proposals are appropriate. The treatment of metering excluded services requires consideration as part of the work being undertaken to develop the scope and form of the separate metering price control.

1.8 Business rates

(Paragraph 3.44)

17. Our responses to the previous consultations and in the BPQs asserted that business rates were a non-controllable cost and should be treated as such. We believe this still to be the case but recognise that DNOs will have input into the 2005 revaluation process. As part of that process we shall aim to minimise the impact of rates on our businesses and ultimately upon customers.

18. The 2005 rating revaluation is well underway. We are actively working with the Valuation Office Agency (VOA) to agree an acceptable process for determining the rateable value (RV) based on the receipts and expenditure methodology.

19. Information consistent with the HBPQ and FBPQ submissions has been provided to the VOA and a series of meetings have taken place to agree methodology, and clarify and interpret data. An initial first draft RV valuation has been provided by the VOA for both

NEDL and YEDL. We have challenged this initial valuation in a number of areas. These include:

- income and unit growth assumptions for the period post-2003;
- incorrect inclusion of deferred tax provisions in operating costs;
- exclusion of weather-related atypical costs from operating costs;
- potential inclusion of increased pensions contributions post-2003;
- treatment of merger savings and their impact on DNO income;
- capital expenditure projections by the VOA post-2005;
- expected level of likely operating cost efficiencies post-2005;
- the expected level of depreciation on tenant assets;
- calculation of the hypothetical tenant's share of assets; and
- consideration of insurance costs.

20. The dialogue between the VOA and DNOs will continue with the aim of agreeing a methodology and data for producing initial RV estimates before the end of May 2004.

21. In the event that rating assessments are determined by the VOA at unacceptably high levels, and provided prescription is not retained, there is the possibility of appeals being lodged. However, such a course is likely to involve significant additional costs and would take a significant period of time to bring to a resolution. If the VOA's proposals are unfair on distribution customers we shall use whatever rights we have to challenge these; otherwise we believe that it is not in the interests of the VOA or of DNOs to introduce more ongoing uncertainty.

22. Whilst it is the current intention of government to remove prescribed assessment they have retained the powers under the Local Government Finance Act to retain prescription if they feel it necessary. Therefore, we would reiterate that, at this stage, there is still some degree of uncertainty as to whether prescribed assessment will be removed. Notwithstanding the fact that conventional valuation methodology was adopted by the VOA for the 2000 revaluation, the assessments were not agreed and appeal rights were denied.

23. We shall keep Ofgem appraised of developments in this area. We also request that Ofgem notifies us of its own expectations of DNOs in this process. We recommend that rates should be treated in accordance with the uncertainty mechanism proposed by DNOs to ensure pass-through.

1.9 Dealing with uncertainty, new obligations and costs

(Paragraphs 3.46 to 3.48)

24. It is clear that all DNOs are faced with future cost uncertainties that make it difficult to assess future income requirements confidently. This needs to be addressed to ensure that companies and customers do not face unnecessary risk in this regard.

25. To cater for this uncertainty, we propose a formal mechanism to ring-fence certain activities / obligations that are known to be required but where the forecast costs are uncertain, and to cater for the addition of new but as yet unknown obligations that may emerge in the future due to changes of law.

26. Such a mechanism is described in detail in the letter, dated 15 April 2004, to David Gray from the Energy Networks Association. CE supports this mechanism and the form of the associated proposed draft licence amendments and suggests that this be adopted for the DPCR4 period.

1.10 Duration of the price control

(Paragraphs 3.49 to 3.50)

27. We agree with the decision to continue with a five-year period between price control reviews.

1.11 Retention period for efficiency savings

(Paragraphs 3.56 to 3.58)

28. We have previously welcomed Ofgem's commitment to continue with some form of rolling adjustments for both opex and capex efficiency savings made in the next price control period. However, we have indicated that we believe that a retention period of longer than five years would maximise the benefits for customers and, as part of our response to Ofgem's December 2003 *Update* consultation, we submitted a paper that provided theoretical justification for retention periods longer than those being proposed by Ofgem. We are disappointed that the March *Policy Document* does not set out Ofgem's rationale for now concluding that there is no evidence that the existing incentives need to be strengthened.

29. We strongly disagree with the application of a blanket reduction in incentives to achieve capex savings (to retention of return only) and have proposed an alternative approach. This is set out in the section on incentives for investment deferral and treatment of overspend.

1.12 Categorisation of costs and changes to incentives

(Paragraphs 3.59 to 3.63)

30. We share Ofgem's concerns that categorisation of costs as capex or opex varies substantially across DNOs and that given the existing incentives companies will be pushed towards capitalising costs. Experience has shown that it is very difficult to set out prescriptive definitions of capex and opex that will be consistently adopted by all companies and over time.

31. Ofgem has proposed some high level principles to mitigate the impact of this problem namely that incentives should be equalised as far as possible where types of costs are substitutes or where definitional boundaries are difficult to enforce. We support these principles.

32. In order to meet these principles Ofgem has proposed that all costs associated with faults (and perhaps also repairs and maintenance) would be treated in the same way as replacement capex i.e. so that it is all capitalised and included in the RAV. We believe the proposals represent a very significant change in policy.

33. Ofgem states that one impact of these changes would be, all other things being equal, to increase the amount of costs being capitalised and included in the RAV. Ofgem has proposed that in order to mitigate the cashflow impact of this change it would need to be offset by increased and accelerated depreciation allowances.

34. These principles could be implemented as follows:

- Faults costs (and potentially repairs and maintenance costs) are expensed in a single year. Therefore income in the DPCR4 period is the same as if it were treated as opex and there in no impact on DPCR4 RAV values; and

- Underspend of fault costs (and potentially repairs and maintenance costs) is treated in the same way as underspend of replacement capex in line with the prevailing capex incentive mechanism. Depreciation allowances are set separately for opex and capex but opex and capex underspends are combined to update the RAV for actual expenditure.

35. The proposals may provide the benefits of a total funding allowance for each company to utilise in order to best meet customer and network requirements, provide additional security of funding over the current approach and may also allow funding for efficient

overspend of faults (and R&M) to be included in the RAV in line with Ofgem's proposed treatment of capex overspends.

36. However, the result of these proposals would be a very much-diluted set of incentives on cost performance that will impact on the rates of return that can be achieved by DNOs in future. With respect to opex that is re-categorised as capex the reward from making these opex type savings will be significantly reduced, which may perversely lead to future efficiency initiatives being mothballed on a cost-benefit basis.

37. It is unclear whether this is proposed as a temporary solution for the next price control review period or a permanent shift. Surely a temporary solution should not have such a fundamental impact on the incentive framework.

38. We are also concerned that if faults, repairs and maintenance and overheads are removed from opex then most or all opex may be treated as capex, which will magnify our concerns on the dilution of incentives.

Alternative approaches

39. There is significant concern in the industry that in order to solve the problem of capitalisation of faults Ofgem may be proposing to throw out many of the virtuous incentive characteristics of the current regulatory framework. There are a number of potential alternative solutions available which retain the current level of incentives. Some of these depend on solving the accountancy challenge, at least in part, and some do not.

40. A possible alternative approach that prevents dilution of incentives but does not require a rigidly consistent approach to the accountancy is outlined below.

41. Faults opex could be treated as replacement capex as proposed but a fixed proportion of the underspend on total capex (faults and replacement expenditure) could be allowed to benefit from the opex incentive mechanism and a fixed proportion could be allowed to benefit from the capex incentive mechanism. The proportion could be fixed based on the proportion of faults and replacement capex in total capex and potentially the proportion of historic underspend on faults and replacement capex.

42. As a simplified example assume that total capex is £100m p.a. and of this £20m p.a. is faults and £80m p.a. is replacement capex. The treatment of total underspend could be as follows:

- 20 per cent based on opex incentive; and
- 80 per cent based on capex incentive.

This would equalise incentives since £1 saved in any capex category would be treated in the same way. For clarity, opex (i.e. non fault or R&M related opex) would continue to benefit from the existing opex incentive scheme.

43. This approach would meet Ofgem's objectives of equalising incentives as far as possible where types of costs are substitutes and where definitional boundaries are difficult to set or enforce. However, it would not lead to the dilution of opex incentives that would otherwise prevail.

44. It may be appropriate to differentiate incentives for opex out-performance along similar lines to the differentiated incentives we have proposed for capex. In the above example a company that had submitted a high capex forecast would find that a smaller percentage of total underspend qualified for treatment in line with the higher opex incentive.

45. Ofgem could fine-tune the methodology from the simplified example in order to ensure a reasonable approach and to ensure that the outcome produces a balanced result across the industry.

46. A further enhancement might be to have three categories of cost for incentive purposes – opex (including overheads) qualifying for the existing opex incentive at one end of the spectrum, reinforcement or enhancement capex qualifying for the capex incentive at the opposite end of the spectrum and faults (and potentially R&M) qualifying for a blended incentive rate in a central category which included all items which might be substitutes. However, this method would involve solving some accounting issues.

47. Our proposal would still provide the features inherent in Ofgem's proposed approach of a total funding allowance for each company to utilise in order to best meet customer and network requirements and could also allow funding for efficient overspend of faults (and R&M) to be included in the RAV in line with Ofgem's proposed treatment of capex overspends.

1.13 Incentives for investment deferral and treatment of capex overspends

(Paragraphs 3.64 to 3.67)

48. We suggest avoidance of the phrase 'incentives for investment deferral'. Simple deferral is rarely virtuous, and therefore should be discouraged. On the other hand, efficient, sustainable changes in asset management practice release long-term enduring benefits to customers and therefore should be encouraged.

49. We are providing, in a separate paper to Martin Crouch, some suggestions as to the best way to meet Ofgem's concerns regarding incentives for investment deferral, and the treatment of capex overspends. The challenge for DPCR4 is to set capital allowances on a comparable basis and to reward companies fairly and equally in relation to the out-performance or under-performance of their respective allowances.

50. Complexity arises from the significant challenge in wanting both to encourage and discourage investment simultaneously, i.e. to ensure that enough investment is made to secure the health of the system while also ensuring that both volumes and unit costs are managed effectively to restrain price increases.

51. Given the broad acceptance across the industry of the need for a general increase in investment, the appropriate course should not be to weaken incentives to invest at the very time where investment levels look set to increase and when future efficiencies will prove much more difficult to capture than those previously released, largely through de-manning. The incentive regime should:

- ensure that the right investments are made;
- encourage realistic forecasts to be submitted; and
- discourage inefficient investment.

We believe that it is possible to achieve these outcomes at DPCR4.

1.14 Operating cost rolling adjustment

(Appendix 1)

52. We support the proposal for companies to retain the benefits of incremental opex efficiency savings achieved during this price control period from 1 April 2003 to 31 March 2005 and during the next price control period for a fixed period of five years (including the year in which the saving was originally made).

Treatment of opex savings in 2003/04

53. We agree that the only year that the opex roller will apply in the current price control period is 2003/04 and that the incentive payment for this year will be based on incremental efficiency savings made during 2003/04.

Treatment of opex savings in 2004/05

54. In the last year of the current price control period, the normal operation of the price control review, without any opex roller, would result in opex underspend in 2004/05 being retained for up to six years, provided that operating costs in 2004/05 are below the 2005/06 allowance by an amount equal to at least the incremental out-performance in the final year. However, if the operating costs in 2004/05 are above the 2005/06 allowance, as is perhaps most likely, then the incremental out-performance benefits would only be retained for a single year. We believe that the DPCR4 price control algebra should be amended to allow any such incremental out-performance to be retained for a full five-year period. This amendment would need to be implemented after 2004/05 actuals are known but could be fully implemented in the post-DPCR4 period.

The opex roller from 2005/06 to 2008/09

55. Ofgem has proposed a set of rules for determination of the opex roller for 2005/06 to 2008/09. We agree that:

- the DPCR4 opex roller period comprises the first four years of the post-DPCR4 price control period (i.e. the rolling adjustment does not apply to the last year);
- at the start of year one of the post-DPCR4 price control period the incentive mechanism will be reset to zero;
- the incentive payment is based on incremental opex efficiency savings in the opex roller period. The incremental outperformance in a given year will be calculated in relation to the highest previous outperformance in that opex roller period;
- in cases of opex overspend this will be offset against opex underspend in the five-year opex roller period. This avoids incentives to load all overspend into any one year;
- the incentive payment is constrained not to be negative in any given year; and
- the incentive payment is calculated when the price control is reset at the periodic review point based on the annual opex profile over the previous price control period.

56. We remain cautious about the use of a multiplier to improve the potential rewards for those companies Ofgem considers to be at or close to the efficiency frontier until there is much higher confidence regarding the robustness of company comparisons and until it is clear how Ofgem intends to give effect to its recognition that lowest cost does not necessarily mean most efficient. However, as previously stated we do not believe that the strength of the incentive currently proposed will maximise benefits to customers in the longer term. The use of multipliers or other solutions such as extending the retention period could remedy this.

57. We believe that exceptional/atypical items should be excluded.

58. We continue to disagree with the proposal to link the incentive to some form of eligibility test as there are other schemes and measures in place, for example IIP, that carry penalties for failure. A further test would introduce double jeopardy.

59. We wish to continue to work with Ofgem to ensure that all parties have a common understanding of the spreadsheet model for calculating payments under the opex roller mechanism. We do not believe that there needs to be an adjustment for underperformance as shown in the worked example in Table 2 of Ofgem's March *Policy Document*.

1.15 Rolling capex adjustment

(Appendix 1)

Existing price control period

60. Ofgem has confirmed that companies will be allowed to retain both the depreciation and cost of capital benefits for a fixed period of five years for all efficiency savings (other than in respect of meters) made during the whole of this price control period. We continue to strongly support the retention of both the depreciation and return benefits and agree that the commitment is conditional on companies meeting their security and supply obligations – upon which Ofgem will take a general view of companies' compliance.

61. It may be difficult to identify efficiency savings in respect of meters separately as meter-related capex was not a separately identified element of Ofgem's capex allowance at DPCR3.

Next price control period

62. Ofgem is now considering reducing the incentives to achieve capex savings. We disagree with the application of such a blanket reduction across the board and have set out our response to this proposal in the section on incentives for investment deferral and treatment of capex overspends. We strongly believe that the rolling capex incentive should continue to retain the depreciation benefits as well as the return benefits.

63. Ofgem is also considering changing the definition of capex from 1 April 2005. Our response on this is contained in the definition of costs and incentives section.

Asset disposals

64. Ofgem has identified that it needs to consider the treatment of benefits received by DNOs from *operational* asset disposals between 1 April 2000 and 31 March 2003. If there have been significant disposals it is proposed that it would not appear appropriate that consumers should continue to fund these assets if they remain in the RAV.

65. We agree that companies should be able to retain the benefits of any asset disposals in the same manner as for operational capex savings, i.e. for a fixed period of five years (including the year in which the saving was originally made).

Non-operational capex

66. We agree that, in the next price control period, non-operational capex should be treated as included in the RAV and depreciated over five years.

1.16 Losses

(Paragraphs 3.68 to 3.82 & Appendix 2)

67. Whilst we are supportive of the proposed simplification of the losses incentive mechanism and the methodology proposed to support it, we have some concerns over its implications.

68. Based on our analysis, our two licensees, which have both had historically good performance at the bottom end of the 6 – 7 per cent range quoted in the March *Policy Document*, would appear to be adversely affected by the proposal. This seems likely to be an unintended consequence of the proposal.

69. Furthermore, we also believe that the regime, as stated, would lead to a reduction in the strength of the incentive as performance improved – largely because reductions in losses become incrementally harder to achieve.

70. We believe that the most appropriate channel for addressing these issues, and the transitional arrangements that may be required, will be through the forthcoming consultation on the implementation of the new losses regime and we shall make our detailed response on these issues there.

1.17 Price control for metering services

(Paragraphs 3.82 to 3.101)

71. We continue to be supportive of the collaborative work with Ofgem and DNOs to develop a separate metering price control. Whilst an appropriate control is not yet finalised, we believe that many of the key issues are now being resolved.

72. One key issue that remains to be considered is how to quantify the impact that the emergence of competitive metering services will have on future contract costs for outsourced metering services.

73. Whilst organisations like ours were able to place outsourced contracts during a time when we still had 100 per cent market share, the risks to the provider were relatively low. In a situation where the competitive market is emerging it is highly likely that the risk exposure of these organisations will be changed when it comes to bidding for our work. This will be driven by two factors. First, the service providers will know that, as a DNO, we are not in control of the development of the market, which of course rests with the electricity supply companies. Secondly, they will also recognise that the timing of de-appointment for meter operation services is a matter of months, not years – leaving little opportunity for them to mitigate the impact on their resources.

74. The difficulty that we all face is that, at the present time, there is no reliable indicator of the materiality of this issue. A mechanism is therefore required to enable the outsourced contract costs to be utilised as the basis of the metering price control, rather than simply setting a price cap.

75. Taking this approach would ensure a symmetrical treatment – i.e. whether a company's costs increase or decrease these costs will be reflected in the marketplace. The developing market will then determine whether market share is lost or not.

76. Obviously, Ofgem will wish to put in place appropriate checks and balances to ensure that the contracts are established properly with appropriate procurement processes followed, etc. However, this represents an opportunity for openness and transparency and should not be considered as a barrier.

77. In summary, therefore, we are broadly content with the process on developing the separate metering price control, particularly since the establishment of the joint Ofgem / DNO metering working group, and we believe that there is potentially a straightforward route to implementing a metering price control for meter operation services for outsourced service providers. We shall continue to work actively with the Ofgem / DNO metering working group to develop these proposals further.

2. QUALITY OF SERVICE AND OTHER OUTPUTS (Chapter 4)

2.1 Guaranteed and overall standards of performance

2.1.1 Severe weather standard

(Paragraphs 4.11 to 4.13)

78. As previously indicated to Ofgem, we support the move for the present compensation terms of EGS2 to apply only in 'normal' conditions and for a further standard to cover supply restoration during severe weather and exceptional events, based on the current interim arrangements.

2.1.2 Automatic payments

(Paragraphs 4.14 to 4.15)

79. The *Policy Document* proposes that DNOs should pay compensation under the 18-hour restoration standard (EGS2) automatically where possible and proactively contact consumers in general to make them aware of their right to compensation under the guaranteed standards framework where there has been a breach, and that this be encouraged by an equivalent penalty where payment is not made.

80. The ability to make automatic payments is limited by the accuracy of the connectivity models used by DNOs and the lack of the names of the customers to whom payments should be made.

81. Under 'normal' conditions virtually all EGS2 failures are as a result of particularly difficult LV underground faults. Here, the lack of phase connectivity means that affected customers cannot be automatically identified. Under severe weather conditions HV faults usually generate the majority of the EGS2 failures, but this position can be complicated by both LV overhead and LV service faults caused by the same event. This can make the exact duration of the interruption seen by identifiable individual customers, and hence the level of payment due, difficult to determine.

82. We believe the above issues make it impractical to operate any form of automatic payment system.

83. However, it is possible to be proactive in contacting customers who may be due an EGS2 payment to inform them of the possible failure and their rights with regard to a payment. A process of this type does not require the absolute accuracy of an automatic system and also only needs the address where the possible failure occurred,

not the customer's name. This would then provide the basis for a semi-automatic system.

84. A customer service issue with the present system is that best practice as defined by Ofgem requires payments to be made via suppliers. This adds a great deal of complexity to the process and results in unnecessary additional delays before customers receive payment. Quite often, customers contact us a few weeks after we have informed them that we have made a payment to their supplier and complain that they have still not received the payment. This is continuing poor service for customers who were probably already unhappy about the breach in the first place, and costly for us in having to then chase suppliers to pass on the payments. It would be much simpler and quicker if DNOs were to make these payments direct to customers. A quicker response in this respect may, to some extent, compensate for not having a fully automatic system. The cost of this solution would be significantly less than that of a phase connectivity system but, nevertheless, would have to be allowed for in the price control proposal.

85. We do not believe that it is appropriate to introduce a mechanism that penalises companies for each customer who does not make a claim under the guaranteed standard, particularly if companies can demonstrate that they are proactive in contacting potentially eligible customers.

2.1.3 Business consumers

(Paragraphs 4.16 to 4.18)

86. We agree with the decision to make the standards and compensation levels for LV connected business customers the same as for domestic customers.

87. We await the results of the willingness to pay survey to inform the decision on the appropriate arrangements for HV customers but reiterate our own views as follows:

- During the design process for a HV connection, HV customers are given the choice of investing in a higher standard of reliability. We consider that such customers are best placed to balance the costs/benefits of a higher reliability of supply against their business needs. Existing customers can also come back to us at any time to re-evaluate such options. Given this situation we would consider it wrong for such customers to get higher levels of compensation than other non-domestic customers for failures of supply when the trade-off between cost and levels of reliability was properly made in their choice of supply system.

- As an industry we encourage businesses to carry out risk assessments on the impact on their output of loss of supply. Our experience is that lost output (and costs) could run into thousands of pounds for even short-duration faults. These amounts can never be recovered from particular business customers' DUoS bills even if the arrangement above were implemented. Standby generation, firm supply arrangements, uninterruptible power supplies and insurance should always be part of the contract discussions when suppliers sign up business customers. Insurance is an individual business's decision and legally it can only be applied for by the particular business concerned.

- With regard to the trigger level for the standard, such customers generally have a choice in the reliability of their supply and are best placed to balance out the costs and benefits against their business requirements. HV customers are given the choice of a firm supply with no interruption on first fault, a cheaper loop-in with automatic changeover where fault interruption times are less than three minutes, an even cheaper straight loop-in where fault interruption times are less than three hours (i.e. switching time), or a minimum-cost tee-connection where fault repair times can be up to 18 hours. As most customers opt for the minimum-cost option knowing the risks involved, it would be wrong for these customers to have compensation paid for shorter interruptions.

- We feel any variation in timescale for particular classes of customer would be discriminatory and would be considered so by the other customers.

2.1.4 Priority service customers

(Paragraph 4.19)

88. We agree that the introduction of a new standard of performance relating to vulnerable customers would not be the most effective approach to improving the service to priority service customers. We support the move to improve the input to and maintenance of the priority services register and look forward to taking part in this process. To ensure that the resulting register is of a manageable size (of the order of no more than a few thousand customers per DNO), the register needs to focus on those customers who are medically dependent on electricity. With this small register we should be able to provide a dedicated contact line, priority feedback and suitable liaison with the other

emergency services on the restoration of supply. However, it must be realised that, with such customers being dispersed throughout the distribution network, it is unlikely that any significant priority of restoration can be given.

2.1.5 Scope of exemptions

(Paragraph 4.9)

89. The March *Policy Document* does not reach a decision on the scope of exemptions. We therefore reiterate our previous response as follows:

- We consider that industrial action by employees should continue to be part of the suite of exemptions. As a business we take all steps to prevent such action and consider that, if it is taken, it is beyond our control. Ofgem can challenge this in any particular situation. Moreover, removing the exemption might alter the industrial relations climate and make the event more likely to occur.

- We consider that inclusion of a new guaranteed standard for severe weather, based on the ‘interim arrangements’, would adequately deal with the treatment of failures due to severe weather.

- We recognise the need to balance risk between customers and DNOs. Where exemptions are removed, or their application is restricted through published *ex ante* guidelines, the costs of an efficient operator (recognising the individual circumstances of each company) in making and administering additional payments must be factored into the price control.

2.1.6 The role of the overall standards of performance

(Paragraph 4.20)

90. We do not have issue with the proposal to discontinue the present overall standards and, where appropriate, introduce similar measurements to be reported as part of the IIP process. We look forward to continuing our participation in the quality of supply working group where detailed negotiations on the replacement measures are being conducted.

2.1.7 Other amendments to GOSPs

(Paragraph 4.21)

91. We agree with Ofgem that, in general, the existing suite of guaranteed standards provides sufficient incentive for DNOs to deliver good levels of customer service and an appropriate level of compensation. We remind Ofgem that the price control for DPCR4 should include an efficient operating cost allowance for the multiple interruption guaranteed standard failure payments and their associated administration costs in DPCR3 and that, if the trigger levels are revised following the willingness to pay survey, these allowances need to be revised accordingly as a small change to the standards will result in a very large change in failure payments.

2.2 Reviewing IIP

2.2.1 Scope of the output measures / disaggregated data

(Paragraph 4.28)

92. We agree with the proposed modified reporting requirements (i.e. disaggregation by HV circuit and by duration bands) and that performance targets should not be introduced for these measures.

93. We agree with the decision to exclude exceptional events from the IIP reporting but more work is needed to refine the threshold levels (see 2.2.10).

2.2.2 Worst-served customers

(Paragraphs 4.31 to 4.33)

94. We support the proposal for multiple interruption reporting based on HV and above faults only to replace the current overall standard. The lack of phase connectivity at LV has meant that most DNOs have had to estimate the performances previously provided leading to a low level of confidence in the reported numbers. From April 2005 onwards, our reporting systems will be able to provide very accurate information on the number of HV and above sourced interruptions experienced by individual customers. This will enable the company to provide the information proposed in paragraph 4.28.

2.2.3 Form of the incentive for interruptions to supply

(Paragraphs 4.35 to 4.36)

95. Ofgem proposes to retain the incentive scheme for the number and duration of interruptions but move to annual rewards and penalties.

96. We have always supported IIP as a means of incentivising companies to deliver cost-effective improvements in the quality of supply provided to customers. Our current view is that, provided the scheme for the period 2005 to 2010 is symmetrical and exceptional events are excluded, then it can be based on annual targets and there will be no need for rolling averages or deadbands.

97. Our preference is for an annual settlement of any penalties/rewards. However, we recognise that this could result in large annual variations in DUoS charges (up to ±4 per cent if the current ±2 per cent cap is retained) and, as such, it may be desirable to smooth this by spreading the recovery of penalties/rewards over several years. We do not consider it appropriate to delay settlement to the start of the next price control period.

2.2.4 Connections measures

(Paragraph 4.34)

98. We support the transfer of the reporting requirements to the output framework. However, we would appreciate the reporting guidelines being clarified to exclude those connections made outside the timescale at the customer's request.

2.2.5 Weighting of planned / unplanned interruptions

(Paragraph 4.37)

99. We do not agree with the proposal to reduce the weighting attached to planned interruptions. Over the last decade all companies have dramatically reduced the level of planned interruptions. The pace of this reduction has been greatly assisted by the inclusion of planned interruptions in the IIP scheme. Removing or reducing the value of these interruptions in the DPCR4 IIP scheme will result in a need to re-analyse the costs/benefits of interruption avoidance measures (e.g. the provision of mobile generators and live line/hot glove working) and could result in some of them becoming uneconomic. This would push up the number and/or duration of interruptions to the detriment of customer service. Note that all of the performance figures provided by NEDL and YEDL in the FBPQ assumed that the present equal weighting of planned and unplanned interruptions continues and the form/scope/value of the IIP scheme remain broadly in line with those applicable in 2004/05. These include an assumption that there will be an increase in the level of planned interruptions to cater for increased investment in the network.

100. NEDL and YEDL, and we believe all other DNOs, are indicating that during the next five years there will be a need to increase the rate at which assets are replaced if we are to maintain the serviceability of the distribution network. The implication of this is that the number of essential planned interruptions will inevitably increase. This will be particularly so if any of the FBPQ quality of supply scenarios that involve enhanced work on overhead lines are implemented. It would therefore not seem sensible, at this time, to reduce the IIP pressure on minimising the level of planned interruptions. We therefore consider that the present equal weighting should be retained, provided that future targets for planned interruptions recognise the increased investment activity that will take place during the next price control period.

2.2.6 Audits and adjusting data for accuracy

(Paragraphs 4.38 to 4.40)

101. We see audits of the IIP reported data as being essential not only to assure Ofgem that DNOs are correctly measuring performance but also to assure DNOs that the consistency is maintained between DNOs. This second factor is particularly important if future targets were to be based on a relative performance assessment.

102. However, we also accept that the current method of audit is time-consuming and therefore expensive.

103. Our own preference for the next price control period would be for an annual self-audit of Ofgem-selected events, with the number of audited events being broadly similar to the current audit. This could be followed by an annual external audit of a randomly-selected sub-set of these events. This would not increase the workload on DNOs but would reduce the time required for the external audit, while retaining the assurance that performance was being correctly recorded.

104. In terms of adjustments, whereas we agree with the current arrangements for adjustments where overall inaccuracy is found to be outside the 5 per cent allowed limits, we are concerned with the proposal to adjust for smaller levels of inaccuracy that are found. Our issue is that the audit itself, with the small number of events that are checked, will only give about a 90 per cent confidence level that the result is correct. Thus audited inaccuracies between ±5 per cent are more likely to be due to the audit itself than actual under- or over-reporting.

2.2.7 Target setting

(Paragraph 4.41)

105. The company welcomes the move to exclude 'severe' events from both the IIP target setting and IIP reported performance. This should ensure that IIP would be based on the underlying performance of the distribution network.

106. However, one issue that has not been addressed is the inequality of treatment of reported performance where one DNO ('A') falls below the threshold for IIP exclusion whereas another ('B') is above the threshold and has performance excluded for the same event. This difference may be due either to 'A' being on the periphery of the event or to 'A' having a better-performing network. In either case, 'A' stands to be disadvantaged by the present arrangements. To correct this inequality, we would suggest that all DNOs be able to exclude the effects of an event for which any DNO has obtained exclusion.

107. The company generally supports the use of the disaggregation process to inform the IIP CI and CML targets. However, this process does not capture all of the inherent and inherited differences that exist in distribution networks and hence the results cannot be used without further corrections.

108. The HV system normally accounts for 70 to 80 per cent of the annual interruption performance and hence has been the area where the disaggregation process has been concentrated. Issues with the direct use of this HV data in its present form are:

- Unit protection of HV circuits can dramatically improve their performance. However, the very high cost of this form of protection makes it uneconomic for retrofitting or for new installations except for large industrial/commercial supplies. Most DNOs have less than 5 per cent of their circuits of this type supplying low numbers of industrial/commercial customers and as such they make little difference to their overall performance. However, two DNOs (SP Manweb and EDF LPN) have historically used a large number of such circuits and their excellent HV performances reflect this. As it is uneconomic for other companies to replicate the volume of unit-protected circuits these two companies have, it is also unrealistic to include the performance of these two companies in setting the benchmarks that other companies are to achieve.
- For the CML benchmark upper quartile performance of CML/CI was used. Where some DNOs have only a small number of circuits in a group, the use of upper

quartile can give misleading results. As an extreme example of this, the L0 band for 2002/03 performance has an upper-quartile CML/CI performance of 0, which is clearly not appropriate. For the other disaggregation bands, the upper quartile CML/CI varies between 69 per cent and 91 per cent of the average CML/CI. Again, if the present upper-quartile calculations were giving a true reflection of actual upper-quartile performance, one would expect the ratio between average and upper-quartile performance to be reasonably stable. A more equitable result may be obtained by using average CML/CI in each of the bands and then taking an overall view on the extent to which upper-quartile performance should beat this. Also, by using CI multiplied by CML/CI for the benchmark CML calculations, the distortions introduced in the CI benchmark by unit protection are also included in the CML result.

109. The above are just some obvious problems with the present benchmark calculations. There may be others that may come out in discussions with DNOs that also need further consideration. We look forward to further discussions on the above which, together with the cost information gathered for FBPQ and the customer willingness to pay surveys, should allow the determination of 'frontier performers' and the setting of reasonable IIP targets for all DNOs.

2.2.8 Treatment of planned interruptions for the final year of the current price control period

(Paragraph 4.42)

110. Ofgem proposes that DNOs should be allowed to roll forward up to two planned CIs and three planned CMLs from 2004/05 to 2005/06 to mitigate any incentive to defer planned work in 2004/05. We consider this to be a useful amendment to IIP for the current price control period.

2.2.9 Frontier performance

(Paragraph 4.43)

111. We agree with the proposal that frontier performers, as benchmarked via disaggregated performance, should be able to participate in the reward mechanism of the current IIP arrangements whether or not they meet both their targets for the number and duration of interruptions in 2004/05.

2.2.10 Network resilience

(Paragraphs 4.48 to 4.52)

112. Ofgem propose to strengthen DNOs' incentive to restore consumers' supplies promptly following a severe weather event by refining the interim arrangements introduced following the October 2002 storms.

113. We agree with this proposal but consider that a great deal more work is required on the restoration standard applicable under extreme weather conditions before fair combinations of times, band size and the levels of funding can be determined. We shall continue to work closely with Ofgem via the Ofgem / DNO working group on this issue.

114. Customers' reactions to the loss of supply associated with recent extreme weather events are indicating a reduced tolerance of the extended interruptions of supply that can occur in such circumstances. However, as indicated by our own and other DNOs' FBPQ responses, the investment required to reduce substantially the probability of loss of supply during such events is extremely large. Equally, there is no indication as yet from customer surveys that there is a willingness to pay for such investments.

115. In the short term, the present incentive regimes, coupled with the low number of extreme events and customers' unwillingness to pay, make it difficult to justify the improvement investments involved. As a consequence, we have not included such investments in our FBPQ DNO preferred cases.

116. However, it will take of the order of 10 to 20 years to make the improvements required to, mainly, overhead lines, so the real question should possibly be 'will customers in 20 years' time tolerate the present level of outages that extreme weather can cause?' We look to Ofgem to take the lead, on behalf of customers and the industry as a whole, in answering this question.

117. If the answer is no, (i.e. some investment is required to address resilience in the longer term) then we have indicated in our FBPQ response the order of work required and the likely timescale needed to complete it. Coupled with this we would accept that it would be reasonable for guaranteed standards associated with severe weather performance to be tightened progressively to reflect the progress of these improvements.

118. If the answer is yes, (i.e. current levels of resilience are accepted and the relevant improvement investments are therefore disallowed), then the present levels of damage

and loss of supply caused by severe events will not improve. Given this scenario, it would not be appropriate to increase the exposure of DNOs to the number of GS payments that they potentially have to fund as a result of extreme weather.

119. The time it takes to restore supplies following a severe weather event is dependent on:

- our ability to gain access to the points of damage;
- weather conditions becoming suitable for repairs to be undertaken; and
- the number of faults.

120. Access times can be very variable depending on the type of severe event. Severe wind events, ice and lightning storms usually only last for a few hours and then access is usually possible shortly afterwards. Snowstorms, on the other hand, can result in access, either by vehicle or helicopter, being unavailable for several days.

121. Although the extreme winds that cause extensive damage to overhead lines tend to last for only a few hours, they can be followed by wind levels still high enough to make it unsafe to commence repairs. Lightning storms are similar, where the risk of further lightning can persist for many hours afterwards, such that working on overhead lines would be unsafe. For ice and snow storms, on the other hand, there would not normally be a weather-related safety restriction on commencing repairs once access was obtained.

122. The above factors result in potential ’start times’ for repairs being anything from a few hours up to several days after the damage incident. The present ’severe weather’ exclusion clause in EGS2 allows for this variable start time but the fixed times proposed by Ofgem for a new severe weather standard, based only on the number of customers affected, do not.

123. Obviously the number of faults has a major bearing on how quickly customers are restored. Note that it is the number of faults that determines how long it will take to restore all customers and not the number of customers affected. For instance, it will take just as long to restore the last customer whether there were 1,000 faults each affecting 10 customers (e.g. 0.7 per cent of NEDL's customer base) or 1,000 faults each affecting 100 customers (7 per cent of NEDL's customer base). The proposed trigger levels between a small, large and very large event based on customer numbers therefore do not seem suitable, with levels based on the number of events being more appropriate.

124. This factor is reinforced when one considers the differences in the number of customers a DNO has 'at risk' of failure from a severe weather event and the number of suitable repair teams available. For instance, if one considers the proportion of customers connected to HV circuits made up of 50 per cent or more of overhead line, this varies from 11 per cent for UU, to 37 per cent for WPD-S.West. Thus UU will, on average, have to have over three times as many overhead line faults to pass a percentage of connected customers threshold compared with WPD-S.West, and will, on average, have only one third of the linesmen available to deal with the faults. This would again suggest that a 'number of events' test would be more appropriate.

125. A further factor will be how widespread the damage is in the country as a whole. In extreme events, affected DNOs call on assistance from others that have not been affected. This works very well when damage is confined to a small area of the country. However, where there is widespread damage this assistance may not be available and very protracted restoration times will ensue (this happened in 1990 when most DNOs were affected by snow/ice storms).

126. The proposed times for a small event (a further 6 or 12 hours over normal conditions before penalty payments start and a presumption that an 'efficient' DNO would restore everyone in 48 hours), and the corresponding times for a large event were determined from an analysis of the wind storm that affected just a small band across southern / central England in October 2002. Following this storm relatively free access was available and weather conditions were suitable for repairs to commence within a few hours. We would argue that the times derived from this one storm are not suitable for application to all the other types of storm that can occur. Indeed, we would go further and argue that the proposed standard would be putting undue financial pressure on companies to commence repairs when it could be unsafe for their staff to do so. To avoid this either the start time (combined with an equal move in end time) of the bands or the level of funding for companies should take the above factors into account.

127. From our own experience of the operation of both EGS2 with its severe weather exemptions and the new interim arrangements, it is clear that customers do not understand why different compensation terms can apply between DNOs affected by the same event. This was a contributory factor in the level of complaints and the resulting Ofgem and DTI investigations following the February 2001 storm in North Northumberland where NEDL and Scottish Power applied different severe weather exemptions. We had further experience of this in the New Year's Eve storm last year

where NEDL applied the interim arrangements (pay at 48 hours) and YEDL fell below the threshold for the interim arrangements and therefore applied the normal EGS2 (pay at 18 hours). One possible way of dealing with this would be to apply the customer compensation terms in accordance with the total number of faults experienced by all DNOs affected but with the level of funding/retention to DNOs based on their own number of faults.

2.2.11 Incentives for telephone response

(Paragraphs 4.53 to 4.66)

Scope of customer survey

128. Increasing the scope of the customer survey to include those customers whose call was answered by automated message would give a wider view of customer satisfaction. However, this would require changes to the messaging platforms to enable customer contact numbers to be extracted.

129. With some development cost the NEDL in-house application could be capable of providing customers' telephone numbers but it is not capable of capturing the customer name or address details. The YEDL messaging system is a BT messaging platform and this does not currently provide the user with the full telephone number. BT are aware of these proposals and indicated that they may be able to provide this data in the future but no timescales have been given. This also applies to NEDL as BT messaging is used as a secondary source of messaging during escalated situations.

Speed of response measure

130. We support the steps taken by Ofgem to determine if the speed of telephone response is a significant factor in customer satisfaction: however, it must be noted that this is a perception issue and not an objective measurement.

Form of control

131. We recognise that, whilst the current scheme has led to a general raising of standards across the industry, it can still penalise companies that achieve a score that indicates that customers are generally satisfied with the customer service offered. We would hope that any absolute measure would recognise this, but also would not penalise companies that had invested in delivering significant improvements in customer service by removing the benefits of maintaining their high standards. We look forward to the proposals in the June consultation.

2.2.12 Environmental reporting

(Paragraphs 4.71 to 4.74)

132. We agree with Ofgem's proposal to begin to introduce a framework for the reporting of certain environmental outputs (e.g. SF6 emissions, oil pollution, amenity issues and environmental management systems) and for there to be no financial incentives on any of these output measures.

133. The recent consultation on version 5 of the RIGs asks for comments on proposed measures in this area and our views on the detail of the measures are provided in our response to that consultation.

2.3 General discretionary award

(Paragraph 4.75)

134. We accept that there are many areas of customer service that are presently not measured by IIP. The company would therefore welcome a discretionary process that recognises and rewards leading-edge performance in such areas of customer service. However, we do feel this award should be provided on the basis that the measures of comparison can be defined *ex ante* and that performance can be measured objectively.

2.4 Undergrounding

(Paragraph 4.76)

135. We await the results of the customer survey, which will assess willingness to pay in this area.

3. DISTRIBUTED GENERATION (Chapter 5)

3.1 Incentive framework for distributed generation

(Paragraphs 5.6 to 5.41)

136. We continue to support the use of a hybrid mechanism to fund the 'shared' and, where efficient, 'strategic' costs of connecting distributed generation, as this approach seems to offer a fair balance between risk and reward for all stakeholders. Specifically, we support the proposals for:

- 80 per cent pass-through;
- collar of the cost of debt;
- cap of twice the WACC;
- absence of specific allowance for strategic investment;
- £1/kW-yr. allowance for O&M; and
- 2 per cent deadband on over-recovery before penal interest applies.

137. However, the proposed scheme is still insufficient to create an incentive that will change companies' behaviour, as:

- the 7.5 per cent return quoted provides too low a premium to differentiate DG from other investment opportunities;
- the reward on successful schemes is too low for the risks we may face, such as:
  - novel techniques that, even after successful demonstration under RPZ, leave us with a higher level of performance risk than conventional solutions;
  - high-cost schemes; and
  - capacity withdrawal by developers.

138. Taking all this into account, we still propose a revenue driver of £2.50/kW per year, under which we would have to bring costs down across the portfolio from £50/kW to £35/kW before we hit the proposed cap. This would provide a higher reward for successful schemes, offsetting the risk of uncertain cost, project failure and novel solutions, and encourage distributors to make significant changes to their behaviour.

Risk and reward

139. Using the £40-50/kW range discussed in the policy paper and the MM-BPI report, the combination of an 80 per cent pass-through (which we support) and a £1.50/kW-yr. revenue driver (which we do not) fails to create strong incentives for companies to change their behaviour in respect of generation connections. The potential rewards on offer remove the legacy imbalance between generation and demand, but go no further.

140. As we have noted before, distributors do not invest just to earn a 6.5 per cent return: all investments have to offer something else, such as improvements in customer service or reductions in risk exposure. Against that background, offering a one per cent premium is insufficient to differentiate investment in DG from any other project.

141. This is particularly acute for those areas where it might be desired to change distributors' approaches, such as:

- making some up-front investment (including yet more pro-active stakeholder management, as well as new network assets) to open up areas for exploitation; and
- introducing novel techniques, which are less certain of releasing the desired capacity than (lower-cost) conventional solutions.

142. We might therefore see new technologies stall. They will be supported by IFI and could be progressed as part of the RPZ initiative. However, if they involve a sustained higher level of risk, the proposed level of reward from the 'production' hybrid mechanism means they will never progress beyond the demonstration phase. That is, unless the RPZ demonstration phase shows that a new approach has the same ongoing level of risk as conventional solutions, the hybrid mechanism fails to offer sufficient reward for us to change.

Uncertain costs

143. We welcome the recognition in the MM-BPI report that: *'In the historical and interim periods, it is clear from the information provided that the policy of deep connection charging has led to self-selection of projects with little need for network reinforcement…the future period is unlikely to resemble the past and the connection costs from the historical period are therefore not likely to be representative of future connection costs.'*

144. It is also clear that distributors have taken a wide view of the impact of the changes to the connection boundary where the details are still being discussed. For example, our

interpretation of ‘sole use’ test is clearly reflected in our relatively (but not uniquely) low view of shared costs. For the avoidance of doubt, our analysis that informed the DG BPQ response suggested that connections would be well dispersed across the system, reducing our exposure to significant reinforcement. Subsequent, more detailed discussions with developers and, in particular, planning authorities have suggested that clustered development may be more likely.

145. All of this leads to significant uncertainty over what the actual average shared costs will be. We therefore welcome the use of a collar and cap to limit the downside for all stakeholders.

146. With the proposed revenue driver, average costs across the entire portfolio would have to rise to £150/kW before we hit the collar of the cost of debt or fall to £20/kW before we hit the cap of 2xWACC. We welcome the principle of the collar and cap but, with this low revenue driver, they are unlikely ever to apply.

147. The gap between the collar for the overall portfolio and the threshold for individual ‘high-cost’ schemes is small. The simplest solution seems to us to be to replace any potential special treatment with an adequate revenue driver in the first place.

148. Further, the figures quoted in the policy paper appear to assume that all schemes will be successful. We assume that the values quoted by companies and reported by MM-BPI adopt the same basis. However, in practice, some investments will fail to realise their desired outcomes despite the best efforts of all involved, so the average cost per kW successfully connected will rise.

Network access

149. We see no reason why generators should be treated as a special case for network access. Any compensation would be disproportionate unless generators had agreed and paid for robust connections (which is the exception rather than the rule). Critically, this proposal runs counter to the oft-described move towards active management (i.e. the use of constraints, rather than ‘fit and forget’) to reduce connection costs: compensating generators when constrained-off would utterly confound the application of constraints to reduce connection costs.

Payments for contribution to system security

150. It has been mooted that, where distributed generation makes a clear contribution to system security (i.e. the network would cease to be compliant with planning standards

in the absence of said generation), then distributors should remunerate generators for that contribution.

151. We recognise that, at the time of connection, it may be appropriate for distributors to rebate connection charges in recognition of reinforcement or replacement deferred. It seems clear to us that such rebates should be treated as capital expenditure and recovered under the hybrid funding mechanism.

152. However, it has also been suggested that generators should receive some annual payment for contributing to system security. Those suggestions have generally been accompanied by a note that the current regulatory framework discourages this, as operating costs are strongly benchmarked while capital costs (such as reinforcing the network instead of relying upon generation) are effectively pass-through.

153. We are not convinced that such annual payments are justified. However, if they were, we would require funding to cover these costs. The description of the revenue driver in the December and May papers clearly states that its intent is to cover the costs of operating and maintaining network assets: we must therefore look elsewhere to fund annual capacity payments.

154. Given the uncertainties over future volumes of DG, we suggest that a simple full pass-through would be the only practical solution. This position is made stronger when we consider the only exception to our scepticism of the need for capacity payments: where we include the contribution of DG to reduce demand at the NGC boundary it will, on occasion, defer the need for Grid connection site reinforcement.

155. In turn, this will hold transmission connection charges at a level lower than they might otherwise have been. It seems to us appropriate, in these situations, that this benefit be shared between demand customers and contributing generators. Specifically, we propose that a sum equal to half the marginal connection charge be distributed between contributing generators and, as their presence has directly reduced exit charges, the costs be recovered as if they were exit charges, i.e. full pass-through.

Implementation

156. Application of the revenue driver should simply be by signed connection agreement for 15 years. Distributors should not be penalised for others' actions: if one developer has been unable to make a commercial return on a given project, it is unlikely that another will and all but impossible for a distributor to make a difference. History suggests that it

is matters well beyond distributors' control, such as the relative pricing of gas and electricity, which has had a dramatic impact on CHP, that determine the life of DG projects.

157. We are unconvinced that using an annuity rather than the conventional approach significantly affects the path of prices, but this is not a significant issue.

158. We welcome Ofgem's recognition of the need for an incentive in respect of microgeneration. We see no particular reason for a different treatment from other generation, and are not aware that any has been put forward.

159. We agree with the need for robust reporting, but we suggest that the audit of the D7 return is a more appropriate process to expand than the RIGs, as generation capacity is already a part of sales reporting.

3.2 Innovation funding initiative (IFI)

(Paragraphs 5.47 to 5.53)

160. We continue to support this scheme, and agree with the proposals in respect of pass through, cap and allowance for internal costs.

161. We welcome joint working, beginning with the production of a distributors' good practice guide: in principle, we agree with combining this with the proposed TSG document for introducing innovation on networks (RPZ), although we need to ensure that the resulting paper does not become unwieldy.

3.3 Registered power zones (RPZ)

(Paragraphs 5.54 to 5.59)

162. We continue to support the principles of the RPZ mechanism, which identifies schemes of particular engineering and commercial merit, and provides for up to twice the revenue driver of the 'production' hybrid DG funding mechanism.

163. We agree that distributors, not customers, should bear the risks of this mechanism. Ideally, RPZs should be transparent to all users, as if they were connected to any other part of the network. The next best solution is that only the relevant generator should be aware, e.g. through accepting potential constraints or the risk of a novel access management scheme.

164. We suggest that innovation should be defined simply as anything outside the scope of current policy for a given company. We recognise that the first application of a given technique within a company may be less worthy than the first application within the industry, but we suggest that this can be catered for by applying a different premium.

165. We are concerned that registration may become an unduly bureaucratic process. Specifically, we need to turn round customer quotations in 90 days, so we need to clear RPZ concepts within those timescales. While we accept the principle of a good practice guide:

- combining it with the proposed IFI guide may provide an unwieldy document; and
- given that these are, by nature, individual applications, it is unlikely that we can cast a good practice guide that is both broad enough to be a manageable document and precise enough to add significant value to the process.

166. We suggest that a single premium rate and a £0.5m pa cap are unduly restrictive. Following our argument on the ‘production’ hybrid DG funding mechanism, we stress that an additional £1.50/kW-yr. is insufficient for:

- additional operating costs;
- risk to maintaining, restoring and potentially compensating for levels of service to other customers;
- risk to maintaining, restoring and potentially compensating for levels of availability for relevant generator(s); and
- cost risk, e.g. for enduring remedial works if the trial fails.

167. Even more than for the production hybrid DG funding mechanism, there is a risk that novel solutions simply will not deliver the required availability. This leaves somebody, most likely to be the distributor, with the costs of remedial works to implement a more conventional solution that will meet customers’ expectations. If there is insufficient premium, distributors will not undertake trials that leave them significantly exposed to such issues: we may also find few generators willing to accept the risk.

168. We therefore suggest that a premium of up to £2.50/kW-yr. (i.e. £5/kW-yr. in total, twice the revenue driver we suggest for the ‘production’ hybrid funding mechanism) be applied, limited only to the number of schemes deemed innovative enough to be granted RPZ status. By extension, the O&M allowance should also be enhanced to

£2/kW-yr. where appropriate, reflecting the additional operating costs likely to be incurred.

3.4 Regulatory impact assessment

169. We welcome the publication of this RIA, demonstrating not just that the IFI and RPZ mechanisms (which we support in principle) are valid but also that Ofgem is committed to transparency and proportionality.

3.5 MM-BPI report on costs associated with DG

170. We welcome this report, and specifically its conclusion that the past is not necessarily a guide to the future, and that shared costs could therefore rise significantly. It clearly shows that there is a range of equally valid approaches (and hence reported costs) to opening up areas for development, including:

- let the first user pay (NEDL/YEDL);
- assume high shared costs (Hydro); and
- assume high strategic costs (SP & Manweb).

171. There is also likely to be, albeit masked by other variables, a range of views of chargeable costs around sole use/sole benefit.

172. Given all this, the conclusion that the average interpretation of the charging boundary leads to shared costs of around £40/kW seems reasonable. However, we must stress that the proposed revenue driver of £1.50/kW-yr. is too low to make a material change in distributors' behaviour.

4. ASSESSING COSTS (Chapter 6)

4.1 Cost normalisation

(Paragraphs 6.13 to 6.17)

173. We agree that there is a need for a robust assessment of costs and would support a transparent process and publication of relevant information. However we would reiterate the need to continue consultation with DNOs on the agreement of methodology, definitions and relevant data ahead of publication, and that certain caveats are made on publication of data (e.g. subject to audit or regulatory accounting changes).

174. We recognise the need for further work on agreement of the normalisation issues and welcome Ofgem's commitment to work with DNOs on this issue.

175. We note that, since the publication of the March *Policy Document,* further work has been completed covering the areas identified in paragraph 6.14[5]. We look forward to exchanging views on the appropriateness of the adjustments and the validity of the resultant data set.

176. Through the normalisation process it has been recognised by Ofgem that DNOs incur additional atypical and one-off costs and we would reiterate our view that Ofgem should make a firm commitment to include an allowance for these atypical events. We would welcome input and transparency in agreeing a process on how this is to be included in the revenue allowance and also some mechanism in the licence to adjust for uncertain costs.

Comments on other DNOs' normalisation adjustments

177. Whilst we appreciate being given the opportunity to comment not only on the adjustments that are being proposed in relation to our own two licensees but also on the adjustments being proposed for other DNOs, we believe it is necessary to point out that Ofgem must not expect this process of reciprocal comment to uncover all the problems of normalisation. We were not present on the visits made by Ofgem and its advisors to other DNOs and are not especially well-placed to know what may lie behind the figures that relate to DNOs that are not in our ownership. What we can do is point out the problems that are clear to us from the data that Ofgem has presented. The

[5] Cost boundaries, capitalisation policies, overhead allocation, outsourcing

comments that we offer are therefore limited to that which is evident to us from the data set presented by Ofgem; we believe that there are likely to be further significant anomalies that we are unable to spot because we only have the data presented by Ofgem from which to work.

Metering

178. We agree, provided a separate control or allowance is made, that an adjustment to exclude all metering costs should be made but it is essential that a clear definition on metering costs is agreed. We note that there is a wide range of costs for this activity ranging from UU £1.2m to EDF Eastern £8.5m, which could indicate significant differences in accounting treatment rather than efficiency.

179. The metering deductions for YEDL and NEDL in the normalisation summary should be £5.1m and £2.5m respectively based on our latest submitted HBPQ figures.

Pensions

180. We agree with the inclusion of an adjustment to exclude all pension costs classified as operating expenditure in DNOs. Again, in setting income allowances recognition of these costs will be required.

Non-operational depreciation and transport

181. We agree that an adjustment is necessary to ensure consistent treatment of non-operational depreciation.

Insurance costs

182. We understand the principle behind the normalisation adjustments but feel that further work is required to explain the wide range of adjustments from nil to £2.6m. In particular we would wish to understand how any adjustments have been made to normalise ‘excess’ limits for property and storm costs between DNOs.

132 kV adjustment for Scotland

183. The adjustment for running a 132kV system for SP distribution would appear to be significantly lower than the £6.1m (at 1997/98 prices) included in Ofgem’s *Final proposals* document issued in December 1999. It would be useful to understand the efficiencies and/or changes in accounting policy that have reduced the cost of repairing and maintaining the 132kV network.

Inter-company margins

184. It was suggested at the Ofgem costs assessment working group in March that inter-company margins would not be deducted as a normalisation adjustment but be treated

as an allowable cost. We agreed with the proposal and would like to understand why it has not been adopted.

DMS costs

The adjustment to add back ongoing DMS cost has been made to six DNO and we would need to understand why other DNOs do not have an adjustment for ongoing DMS costs. All DNOs should have some ongoing DMS work.

Lane rentals / congestion charges / overstay penalties

185. We feel that an adjustment should be made to exclude the 'trial' lane rental costs incurred by DNOs. Again, in setting income allowances recognition of these costs will be required.

Capitalisation policies

186. We believe that adjustments are necessary to reflect inconsistencies in capitalisation policy but without the knowledge of the absolute numbers for tree cutting, tower painting and inspections it is difficult to compare the normalisation data in this heading to ensure consistent accounting treatment.

187. We would conclude that the normalisation process to date has resulted in a data set that is more useful for the benchmarking exercise. However it may still contain significant definitional issues, which suggests that rather than a frontier or upper quartile approach to setting allowances an average approach is appropriate.

4.2 Bottom-up modelling

(Paragraph 6.18)

188. We await the outcome of PB Power's and Ofgem's approach in the June initial proposals document.

4.3 Top-down modelling

(Paragraph 6.19)

189. Regardless of the method of assessment it is important that NEDL and YEDL are allowed their efficient costs after taking into account the outputs that each DNO delivers. Other performance aspects must be considered, in addition to cost, when assessing efficiency.

190. If regression is to be used as part of the cost assessment process, we consider an OLS (or average) approach to be the most appropriate technique, taking into account the potential errors in the normalisation process and the determination of the composite

scale variable (CSV). An OLS approach would also be better for incentives by allowing the lower cost companies to enjoy the benefits of efficiency savings for longer. Care must be taken to ensure that the data used is accurate and from audited sources where possible. Whilst we believe that the normalisation process has come a long way, we are not confident that the results of that or the accuracy and consistency of certain elements of the CSV data can ever justify a benchmark other than the average.

191. There is no compelling case for regulators to anticipate future efficiencies by applying an ongoing improvement expectation to any derived benchmark, particularly as future efficiency savings are proving harder to achieve. The incentive properties of RPI-X regulation will bring forward any efficiency projects that yield a positive NPV. Companies should not be expected to pass the benefits from these savings onto customers before the savings have been made. The significant rate of TFP gains achieved during the period since privatisation is not an indication of future likely trends. The RPI captures the productivity gains of the UK economy and to consider a benchmark shift when setting the price control assumes that DNOs can continue to significantly improve upon the efficiency gains in the economy as whole. This is clearly not credible.

4.4 Mergers

(Paragraphs 6.20 to 6.24)

192. With regard to Ofgem's policy on the treatment of mergers, the *Policy Document* states that it may not be necessary to adjust DNOs' costs for merger savings for the purpose of benchmarking. We agree with this thinking.

193. To be consistent with its declared policy at the time of the NEDL/ YEDL merger Ofgem must now ensure that it does not penalise companies by taking merger savings twice – once through the use of a benchmark that is derived from cost levels in which merger savings are embedded and again by a further merger adjustment. Ofgem would also have to take care to ensure that NEDL and YEDL enjoyed the full benefits of merger savings until the fifth anniversary of their merger (i.e. until 2006/07). We are taking Ofgem's silence on any additional merger adjustment in the March *Policy Document* to be consistent with this understanding.

4.5 RAV roll-forward

194. The March *Policy Document* states that Ofgem will be in a position to say more about this issue in the June *Initial Proposals*. At this point, therefore, we shall merely reiterate our concern that we should not be disadvantaged relative to companies whose disclosure was not as complete as was our own, and we also wish to ensure that any failure by others to disclose information to Ofgem (for whatever reason) at DPCR3 should not leave either NEDL or YEDL in a relatively worse position. If some companies are allowed to carry forward the consequences of this treatment into DPCR4, it requires that something equivalent be done at DPCR4 to ensure that all companies are treated equitably. Failure to make an equivalent adjustment would preserve the unequal treatment into the future. However, we also appreciate that customers should not be expected to pay the same set of costs twice; once in opex and once in capex. Our proposal therefore is that, for the period ending 31 March 2005, Ofgem should restore to the RAVs of the companies who behaved in accordance with Ofgem's intentions that element of fault cost expenditure that they were deprived of by the efficient frontier methodology where the frontier was set by a company whose operating costs did not include all of its fault costs.

195. The RAV roll-forward for DPCR4 should ensure that similar inequities are not built into the DPCR4 settlement. Thus, where Ofgem has made an adjustment to the level of overhead costs attributed to opex and capex in the DPCR3 period, this needs to be reflected in the derivation of the opening RAV for the DPCR4 period.

5. FINANCIAL ISSUES (Chapter 7)

5.1 The financial ring-fence

(Paragraphs 7.2 to 7.16)

196. We welcome Ofgem's view that no significant strengthening is needed to the existing arrangements and feel that the changes proposed are reasonable.

5.2 The cost of capital

(Paragraphs 7.17 to 7.19)

5.2.1 Overview

197. We welcome Ofgem's approach to adopting a consistent method for setting the allowed cost of capital, in terms of utilising CAPM and also the transparency of the evidence considered in arriving at the key parameters.

198. However, as we indicated in our response to Ofgem's December *Second Consultation*, the recent work that NERA has conducted for both the water industry[6] and EDF[7] indicates that the CAPM model should not be biased by short term market conditions on specific components such as beta and debt premia. This work also draws on international benchmarks and suggests cross-checks to other methods should be utilised since CAPM is recognised as under-estimating the true cost of capital.

199. This requirement to recognise European utility returns was also made by the analyst at the recent Ofgem workshop.

200. The NERA report for EDF was submitted in response to Ofgem's December *Second Consultation*. NERA has also recently updated their report for the water industry and we understand this has been submitted to Ofgem. Both of these reports suggest a higher cost of capital than Ofgem's upper band and do not support the proposed lower bands.

201. This is further supported by comparison to Ofwat's view that the bottom of their range will be 5.0 per cent on a fully post-tax basis, which is the top of the Ofgem range; this discrepancy is not explained by the different risk profile of the business.

[6] NERA – UK water cost of capital - A final report for UK water – March 2004
[7] NERA – A Report for EDF energy – March 2004

202. We would, therefore, urge Ofgem to re-consider the evidence to arrive at a range of bands and then select a cost of capital at the upper end to ‘reflect the strong investments focus of this review’, which may have resultant issuance costs.

203. We would also remind Ofgem that we submitted a paper in December 2003[8] on embedded debt and maintain the debt incurred by NEDL and YEDL was efficiently incurred and should be allowed in the cost of capital.

204. In the following section we comment briefly on the specific components but for brevity do not duplicate fully the evidence from NERA.

5.2.2 Comments on Individual Parameters

Risk- free rate

205. This is an example of a range which has a too low bottom band and there is evidence to support a central estimate at the top end of the banding. We do not support the arbitrary widening of the range and support NERA’s international evidence of a risk-free rate of 2.9 per cent.

Equity risk premium (ERP)

206. We, again, believe a different interpretation of the evidence would arrive at a higher lower band and there is a strong case for adopting a global rather than country-specific approach when determining the prospective ERP, which would give a result at the top end of the range.

207. The lower end range seems to be driven by data from the Welch[9] survey based on a one-year forecast, however, Welch also published data based on a 30 year-forecast which was 1.6 times higher.

208. Dimson, Marsh and Staunton[10] conclude that the global arithmetic prospective ERP is 5 per cent; we would support such a view.

Equity beta

209. NERA, in its water industry report, provides evidence for water companies and the rationale for falling betas, i.e. market volatility. We would comment that the business fundamentals of the sector have not changed dramatically to justify the recent fall in the beta estimates, which supports the fact that wider market factors are at work.

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[8] CE Electric and Barclays UK report submitted 9 December 2003
[9] Welch (2001) The equity premium consensus forecast revisited
[10] Dimson, Marsh & Staunton (2003) Global evidence on the ERP

210. We would support the continuance of the view of an equity beta of 1.0 at 50 per cent gearing. We comment on gearing below but would point out that if a higher gearing than 50 per cent is assumed it follows that financial theory would indicate an equity beta of greater than 1.0 would be required.

Debt premium

211. We would support Ofgem's range for 'expected' debt premium of 1.0 per cent to 1.8 per cent, which recognises that the current evidence may be temporarily depressed due to increased demand for corporate debt.

212. However, as indicated earlier and in our previous responses we believe the actual debt previously incurred by NEDL and YEDL was efficient and should be allowed in the cost of capital.

213. For ease of reference, a further copy of our December 2003 report on the historic cost of debt is attached and the conclusions from the report are reproduced here:

> *The principles of incentive regulation should ensure that the rate of return allowed is sufficient to continue to attract capital to finance future investments. This principle requires Ofgem to allow existing providers of finance adequate returns to recover the cost of past investments.*
>
> *If Ofgem's forward-looking estimate of the cost of debt does not take account of the embedded cost of debt, then it is implicitly assuming that all the historic debt can be refinanced at existing spot rates without payment of financial penalties. Clearly this is unrealistic and is equivalent to disallowing other sunk costs, with the same implications for regulatory risk and incentives.*
>
> *The regulatory process has to ensure that all of the components of the allowed income of the DNO are incurred efficiently. Within an incentive regulatory system there can be no 'blank cheque' for any element. Regulation cannot provide a guarantee to cover the costs of a DNO's actual debt portfolio. But financing which satisfies objective prudency tests should be allowed over the length of the financing period.*
>
> *DNOs want to make efficient long term financing decisions. In order to do this the existing debt costs must be remunerated in full. The only exception being if Ofgem can demonstrate that these costs arose as the result of particular kinds of financial mismanagement or inefficiency that need to be discouraged in the future.*
>
> *We would therefore support an adjustment to the allowed cost of capital for NEDL and YEDL in respect of embedded debt costs. Such allowance to be subject to Ofgem applying objective tests of prudency.*
>
> *We look to working with Ofgem on the resolution of this issue.'*

Gearing

214. Whilst supporting an assumed level of gearing, we believe Ofgem should maintain the assumed level of gearing at 50 per cent despite evidence that investment grades can be maintained with higher gearing for the following reasons:

- to assume a higher level will incentivise companies to push gearing levels even further;
- the sector as a whole is facing an increase in capital requirements which it needs to finance, the incentive to increase gearing will mean the finance requirement is likely to be met from gearing up so pushing the industry average even higher;
- higher levels of gearing result in less financial flexibility to respond to unforeseen circumstances and weaken incentives for innovation; and
- care also needs to be taken to avoid systemic failure within the sector.

5.2.3 Comments on alternative approaches

215. *Alternative Approach to Risk-Free Rate and ERP* - internal consistency is achieved by assessing these two parameters as the average of a long-term historical series not by combining upper and lower bands.

216. *Aggregate Return on Equity Approach* – Smithers & Co[11] use a historical estimate of ERP and a forward looking estimate of the risk-free rate, this approach is likely to understate the cost of equity, since high current market volatility will depress yields on government bonds used to estimate the risk-free rate.

217. *Dividend Growth Model* - we would recommend a comparison of the parameters of those utilised by NERA in past studies.

5.3 Financial indicators

(Paragraphs 7.20 to 7.22)

218. We are disappointed that Ofgem has not yet been able to share its thoughts on financial indicators and we therefore await the June *Initial Proposals* paper with interest.

219. We believe that there are still some significant unresolved issues with respect to the financial model. These need to be addressed at the detailed level in order that we can

[11] Smithers & Co – A study into certain aspects of the cost of capital for regulated utilities in the UK – February 2003

have confidence that the model's outputs can be used to inform the debate on financing. We have submitted our views and these are included in an appendix to this response.

220. As discussed in bilateral meetings the modelling work on ratios must look at the results of 'bare' regulation (i.e. assuming no out-performance). The improved financial position which arises from the impact of such as rolling capex and opex incentives from the current regulatory period cannot be used as a means of satisfying the minimum financial criteria in the next review period.

221. We continue to oppose the use of accelerated depreciation as a means of addressing any cash flow issues that may arise in the next review period. The allowed income should allow debt and equity holders to receive the appropriate cash flow during the period without deferral. If cash flows are inadequate to achieve this result then the overall level of return needs to increase. Whilst accelerating depreciation generates additional cash flow it does not address the underlying issue.

5.4 Pensions

(Paragraphs 7.35 to 7.45)

222. Our concerns with regard to pensions relate to the allocation between price-controlled and non-price controlled activities, the treatment of over- or under-provision and the treatment of ERDCs. The last of these is the most material issue.

223. We see practical difficulties in trying to allocate liabilities on the basis of the last employment for anyone who left the business before full legal business separation was achieved. We suggest a method that reflects the share of employee-related costs borne by the distribution business at privatisation.

224. We believe that NEDL and YEDL (after the acquisition by CE) have made greater contributions than were envisaged by Ofgem in their DPCR3 assessments since, although the scheme was in surplus, NEDL and YEDL continued to pay the full contribution to the 'principal employer'. We are concerned that we should not be disadvantaged relative to other DNOs or with respect to the assessment for the DPCR3 settlement. However, we agree with Ofgem that this issue must be considered in conjunction with the treatment of ERDCs.

225. We strongly disagree with Ofgem's conclusion that adjustments reflecting the use of surplus to fund ERDCs are necessary before the share of the deficit to be borne by

distribution customers is determined. We believe that Ofgem's underlying reasoning for this proposed treatment, as set out in the March *Policy Document*, is inconsistent with some previous Ofgem reasoning, and is inconsistent with the basis on which all previous RPI-X price control reviews of have been conducted.

226. In the absence of a clear prospective signal of a change at DPCR3 to the usual principles of price control the only circumstances in which an adjustment would be justified would be where a DNO had been reckless or negligent in its use of the surplus and had thereby contributed to the scale of today's deficit. In the March *Policy Document* Ofgem is clear that it is not alleging any reckless or irresponsible behaviour on the part of DNOs.

227. The methodology for DPCR3 included an allowance for redundancy and restructuring costs and we believe that, in making allowances for one-off costs in the DPCR3 final proposals, Ofgem had taken into account the scheme surpluses that were known by that date. We therefore believe that there is no reason for treating the ERDC component of the future funding requirement differently from the other elements of the future funding requirement.

Appendix 1: Ofgem financial model

The following issues were highlighted in an email to Ofgem dated 26 April 2004.

We have been attempting to validate the latest version (April 2004) of the Ofgem model by populating it with FBPQ data. Whilst we understand that the model is not designed to replicate the FBPQ results we have had some difficulty in validating the results for YEDL and have therefore been unable to prove the model to our satisfaction. We have therefore decided not to progress the NEDL model at this stage.

As there is not much documentation on the model we have made our own assumptions about where input data should be taken from. Some of our assumptions may be incorrect and may be part of the reason we are unable to produce consistent results.

We would therefore suggest that there needs to be sufficient documentation available to link FBPQ (and other) data to the model inputs.

We believe the following errors exist in the model:

- In the IBA tax calculation on the **NotesToFinReps** sheet the writing down allowance calculation has the wrong formula. It picks up previous year allowance rather than the balance, has brackets missing and deducts the additions rather than adding them.

- Operating cost analysis on the **NotesToFinReps** sheet (rows 43 to 56) which link to the DNO inputs has formula which are out of line and do not pick up all of the operating cost items.

- The calculation on row 10 of the **PriceControl** sheet is inconsistent across years - **SelectedInputs** row 18 (NTR costs) is added to 2009 only but should be included for all years.

We also encountered problems in the following areas:

- There seems to be a disconnect between the capital expenditure used in the price control calculation and that required for balance sheet. We can either get the correct results from the price control model or from the financial statements but not both together. How should FBPQ Adjustments onto a RAV basis be accounted for in the model? This also impacts depreciation and tax calculations.

- Capital allowances pools assume that values roll on from the March 2003 HBPQ values to FBPQ but they don't. We have entered FBPQ 2004 Opening Balances. However the model assumes that 2004 additions have been entered and then calculates percentage additions to each pool. With no additions the calculation produces an error. Is the result of this calculation used anywhere in the model or is it for information only?

- Interest is calculated based on net debt at the end of the previous year with no adjustment for current year cash flows. This approach oversimplifies the position and will lead to incorrect ratios being calculated. The model should adjust for cash flows in the period.

- A single interest rate is applied to all net debt with no inputs to allow for other debt at various interest rates. Therefore a calculation is required to determine the ‘implied average’ interest rate applicable to the DNO (for example based on input net debt and the interest charge). If the model is to continue with this approach then it should include a facility to calculate (and vary) this average rate.

- The model does not allow for equity injections to be made during the price control period and should be amended to do so.

- Cash interest is assumed to be the same as the interest charge in the Profit and Loss account. This is not necessarily the case. (FBPQ Cash Interest is greater than the Profit and Loss interest charge by £3m to £4m in each period). As a result the net debt figure is incorrect and future interest charges are also incorrect.

- We have been unable to input the correct cash tax for 2004 as the 2004 payment is not based on half of 2003 + half 2004. This impacts the net debt calculation.

- Debtors (and other working capital items) are assumed to grow with inflation (i.e. constant in real terms) even though turnover falls. This will impact cash flows and net debt. The model should be more flexible in its approach to modelling working capital.

- All of the above items will further impact on the cash flows in each period and therefore net debt and interest calculations will be incorrect.

- We have not yet been able to prove that the post tax price control model works as we have not been able to reconcile the overall tax calculation. However we have been able to reconcile the pre tax price control calculation.

- We have not been able to verify the ratio calculations as we have not been able to successfully complete the financial statements due to the issues highlighted above.

We have the following suggestions to further improve the model:

- Simplify the Nominal to Real price level conversion by calculating a conversion factor once for each period instead of having similar calculations in multiple cells

- Align columns on sheets so that for example 2006 is always column S.

- Both of the above items would greatly simplify the ‘readability’ of the model from a user’s perspective.

- Assumed gearing is an input to the model. It might be useful to include an actual gearing calculation on the Summary Results page.

- Include additional workings on the DNO input sheet to allow the input of data directly from FBPQ tables where the data is required to calculate percentages used in the model - e.g. capital spend to tax pools, interest to be applied to debt, gearing etc.

- The model requires further documentation (preferably within the model) to provide greater clarity between the model inputs and calculations and the FBPQ tables. Specifically, it would be useful if for each data item the model included a reference to the appropriate FBPQ table and row.

We hope this helps in the further development of the model and look forward to the opportunity to contribute further at a future modelling workshop. We would also ask for confirmation that the issues raised in our letter of 13 November 2003 to which you replied on 10 February 2004 have all been addressed.

Capex funding: a discussion paper by CE Electric UK

Summary

1. We recognise concerns over the need, in the consumer interest, to balance incentives on distributors to:
   - invest up to the levels required to secure the health of the system; and
   - constrain costs downwards.
2. We suggest a change of approach to setting the price control, to move from trying perfectly to predict out-turn investment to establishing a framework that:
   - provides sufficient funds for all necessary investment; and
   - creates incentives for efficiency.
3. Such a framework should also reinforce the need for distributors to put forward transparent, robust and realistic forecasts of investment need.
4. A helpful precedent is Ofgem's proposal for a hybrid DG funding mechanism. This consciously avoids defining the 'right' level of investment, but instead creates a framework that provides sufficient funds for the investment that distributors subsequently deem to be required.
5. Specifically, we suggest setting separately a benchmark for incentives and an assumption for price control. This benchmark might be defined as a band rather than a point, e.g. between 120% and 140% of out-turn in the previous period, so that:
   - high forecasters (i.e. projection above upper benchmark) would get the upper limit as base assumption for price control, with:
     - overspend funded at return plus depreciation, subject to an efficiency test, in a similar approach to that proposed in the open letter on gas distribution price controls; and
     - savings (below the benchmark, rather than the original projection) rewarded at return, until savings equate to twice the gap between upper and lower benchmark, and rewarded at return plus depreciation for further efficiencies;
   - medium forecasters (i.e. projection between upper and lower benchmarks) would get their projections as base assumption for price control, with:
     - excess funded as overspend where efficient; and
     - savings rewarded at return, until savings equate to twice the gap between projection and lower benchmark, and rewarded at return plus depreciation for further efficiencies; and
   - low forecasters (i.e. projection below lower benchmark) would get the lower limit as base assumption for price control, with:
     - excess funded as overspend where efficient; and
     - savings rewarded at return plus depreciation.

6. A number of factors could influence the benchmark including:
   - absolute out-turn levels (e.g. 120% of expenditure in the preceding period);
   - £/customer comparisons (e.g. £70/customer-yr.);
   - asset turnover relative to RAV or MEA (e.g. 2% pa of MEA);
   - PBPower investment modelling; and
   - special factors in the FBPQ that warrant treatment as base case expenditure
7. We contend that this both secures sufficient funds for large investment programmes while retaining incentives for efficiency, in each case leaving it clear that distributors have the responsibility to determine and the means to deliver effective capital investment. It also has the advantage of encouraging distributors to provide reasonable forecasts.

desired behaviours

lasting efficiency as opposed to simple deferral

8. Firstly, we suggest avoidance of the phrase 'incentives for investment deferral'. Simple deferral is rarely virtuous, and therefore should be discouraged. On the other hand, efficient, sustainable changes in asset management practice release long-term enduring benefits to customers and therefore should be encouraged.
9. To illustrate the difference, let us assume that a given asset population has a flat survivor profile and that each example was previously due to be retired on its 40th birthday. Simple deferral by five years would allow us to save the entire tranche of capital investment for five years but, in the following five years, we would have to double investment to replace both due and overdue units.
10. Conversely, if we implemented better asset management techniques that allowed us to extend lives to 45 years, we would again make substantial savings for five years, but then remain at a more reasonable level of investment. Indeed, in the long term, we would move from replacing 2.5% of that asset population each year to replacing 2.22%, a year-on-year saving of 9%.

managing and monitoring asset condition

11. We agree that it can take time for the impact of under-investment to be made manifest at a high level. However, with a large and diverse asset base it is possible to establish indicators that will pick up the leading edge of any potential deterioration in asset and/or network performance. This is something we are developing as part of our internal investment planning practices, to give us greater awareness of and confidence in the risks we manage.

12. In this area, the MTP report has proved an effective first step. We suggest that this can be developed, albeit likely on a company-specific basis at the detailed level, to give greater visibility of the sub-classes of asset behind the prescribed categories. For example, we could disaggregate LV underground cable performance by PILC, 'intermediate' plastic-insulated cables such as ALPEX and CONSAC, and 'modern' plastic cables such as waveform, to highlight whether any one type gave particular grounds for concern.

provision of reasonable, credible forecasts

13. We have found the 'summary of DNO forecasts' illuminating. It is hard for us to believe that all base cases have been created equal, either on the basis of investment per customer or on the trend of investment over the ten years shown. It seems to us that, without substantial review of some of the higher projections, some distributors would find it easier to outperform their forecasts than others.

14. There is a range of reasons for differences in forecasts, some of which are legitimate investment decisions while others may be deemed to be gaming. However, all appear to involve differences in interpreting what seemed to us to be straightforward guidance to maintain the level of performance and (financial) risk from 2004/5 to 2009/10. These reasons include:

   - advancement of investment into the period up to 2009/10 when risk profiles suggest it might not be required until later, to smooth delivery profiles;
   - deferral in the period to 2004/5 and consequent catch-up to 2009/10;
   - deferral from the period to 2009/10 into later years, to smooth delivery profiles, although this might be expected to increase risks and therefore seems unlikely;
   - cost-risk contingency, i.e. including uncertain costs within base case submission when they should (arguably) have been recognised in the supporting narrative (specifically the response to overall base case 8); and
   - deeming the continuation of current investment practice to be base case, even though it improves the risk profile, such as significant overhead line upgrade programmes.

15. We believe that Ofgem has, over the last four years, sent clear signals that reasonable forecasts were required and that gaming would be punished. Companies that have submitted forecasts that are notably out of line with reasonable expectation, whether driven by perceived engineering need or something less noble, cannot now be surprised if those submissions are adjusted sharply downwards or if they are offered significantly less scope for potential rewards for spending less than those forecasts.

16. However, it is too late now to encourage companies to submit reasonable capital investment forecasts for this review, as the forecasts, reasonable or otherwise, have already been submitted. Whatever Ofgem now do cannot influence *those forecasts*. An incentive mechanism that is solely directed towards influencing forecasting will still influence forecasts for the next review, but does not address funding to 2010.

17. The challenge now is to set allowances on a comparable basis and to reward companies fairly in relation to the out-performance or under-performance of that allowance.

encouraging good behaviour

ensuring adequate incentive to invest

18. It is essential that the incentive properties of the price control regime must not penalise those companies that submitted reasonable forecasts, or reward unduly those that presented unjustifiably inflated projections. It seems therefore that we need to establish some kind of benchmark against which to assess these submissions. From a comparable starting point Ofgem might then establish some sliding-scale control around that benchmark that, on the one hand rewards efficient underspend and, on the other, releases funds for efficient overspend.
19. This should give us some comfort that we are not reinforcing undesirable behaviour, where spending too little can be as detrimental to customers as spending too much. However, we must remember that the current regime has within it the power to penalise companies that have neglected their networks where that neglect gives rise to breaches of the licence of the enforceable obligations of the Electricity Act 1989 (including the obligation to develop and maintain an efficient network). These enforcement powers are backed by a regime of significant financial penalties. These are important incentives for companies.
20. Bearing in mind these potential adverse consequences of neglect we believe that the current regime is broadly appropriate because it rewards companies that avoid unnecessary investment, but it is appropriate and fair only if the initial income allowances are set reasonably for each company.
21. We recognise the concerns expressed by TISC and other commentators that the pressures on reducing expenditure may be too high, but we suggest that this is primarily an opex, not capex, issue. Strong incentives to manage investment should also be recognised as providing a reward for greater financial risk, akin to an insurance premium that provides a cash cushion for future cost shocks.
22. This reflects our approach to setting and managing the investment plan. We produce a ‘residual risk’ paper, that outlines to directors the potential for future cost shocks, so that they may prepare accordingly. This approach has been continued in our FBPQ submission, where we have discussed uncertainties in the narrative and not included contingencies in the tables.
23. The recent TISC report shows that there is genuine and significant uncertainty over the right level of investment. It seems to us that the worst possible position is tempting companies through strong incentives to under-invest, within reasonable bounds, then leaving them without the funds to recover if they got it wrong. Allowing the return only as an incentive is insufficient to avoid this, as the rewards do not properly balance the (financial) risk, and companies could not readily set aside sufficient funds to cover contingencies.

ensuring incentives to increase efficiency

24. The complexity of this situation arises from the significant challenge in wanting both to encourage and discourage investment simultaneously, i.e. to ensure that enough investment is made to secure the health of system while also ensuring that both volumes and unit costs are managed effectively to restrain price increases.

25. Ofgem is rightly concerned to protect customers from some of the current properties of the existing regime – namely that a company is always encouraged to increase a forecast for investment, since the incentive to outperform that forecast are strong and the disincentives for forecasting high are (to date) very low in comparison to the gains of outperforming. That said, given the broad acceptance across the industry for a general increase in investment, it seems barely credible that the appropriate course of action would be to weaken incentives to invest at the very time where investment levels look set to increase and when (it is widely accepted that) ongoing efficiencies will prove much more difficult to capture than those previously released, largely through de-manning.

26. Therefore, we suggest a change of approach. The only thing we can say with certainty about any forecast is that it will be wrong. We should perhaps move from trying perfectly to predict out-turn investment to establishing a framework that:

    - ♦ provides sufficient funds for all necessary investment; and
    - ♦ creates incentives for efficiency.

27. A helpful precedent is Ofgem's proposal for a hybrid DG funding mechanism. This consciously avoids defining the 'right' level of investment, but instead creates a framework that provides sufficient funds for the investment that distributors subsequently deem to be required. Similarly, we could adopt a less prescriptive approach for 'base case' capex that is flexible enough to fund the investment required without having to define it precisely in advance.

using benchmarks to match funding to investment

28. A simple option is to define a benchmark for both the incentive scheme and 'central case' allowed income that is explicitly not a determination of required expenditure. Instead, it is a view of how customers should fund the investment that directors decide is required, and that Ofgem will review through ARM, MTP & IIP. This is similar to the zero-based budgeting of hybrid DG, and builds on the recurring Ofgem proposal to fund low and provide flexibility upwards rather than fund high and risk distributors taking liberties.

29. A number of factors could influence the benchmark including, by individual distributors and sector as a whole:
    - absolute out-turn levels (e.g. 120% of expenditure in the preceding period);
    - £/customer comparisons (e.g. £70/customer-yr.);
    - asset turnover relative to RAV or MEA (e.g. 2% pa of MEA);
    - PBP investment modelling; and
    - special factors in the FBPQ that warrant treatment as base case expenditure
30. Comparing forecasts to out-turn recognises what might be deemed a *modulus of elasticity*, i.e. how much the level of investment might reasonably be expected to change, both within and between regulatory periods.
31. Under this proposal, companies would then be free to decide how much to invest, with both they and Ofgem acutely aware of moral and legal obligations. Here we must disagree with TISC, as we believe that these wider obligations provide an absolute check on potential under-investment.
32. The 'central case' funding would be set at the benchmark, with companies free to spend:
    - more, funded as 'efficient overspend' at return plus depreciation; or
    - less, rewarded as capital efficiency at return plus deprecation
33. This would ensure that high forecasters were adequately funded, as they would receive as much as if the process (both their plans and Ofgem's scrutiny) were perfect, without being rewarded for gaming. It would also ensure that low forecasters were rewarded for their prudence, and send a yet clearer signal for future reviews: a side benefit is that they would receive a cash cushion to protect against possible future cost shocks.

34. We recognise potential concerns that some distributors might profit unduly, as their forecasts would be below benchmark funding. However:

    - ♦ there is clear precedent from the last review, where Seeboard and Sweb were each allowed income based on assumed investment significantly higher than their own forecasts (£349m against £315m and £356m against £327m respectively, each excluding QoS and in 1997/98 prices[1]); and
    - ♦ this approach would remove the inequity of a distributor that inflated its forecast (perhaps honestly) receiving a higher allowed income than one which had presented a pared-down forecast. That is, some distributors might include investment in their base case that others did not, such as enhanced tree-trimming programmes or small-section conductor elimination. This might not be obvious, and might not therefore be adjusted, leaving one distributor with a higher allowance than the other even though the expectations of performance for each was the same. The benchmarking approach proposed here would reduce this risk.

35. There are many potential variations about this. One such, which differentiates between benchmark for incentives and assumption for price control, is that the benchmark is defined as a band rather than a point, e.g. between 120% and 140% of out-turn in the previous period, so that:

- ♦ high forecasters (i.e. projection above upper benchmark) would get the upper limit as base assumption for price control, with:
    - o overspend funded at return plus depreciation, subject to an efficiency test, in a similar approach to that proposed in the open letter on gas distribution price controls; and
    - o savings (below the benchmark, rather than the original projection) rewarded at return only;
- ♦ medium forecasters (i.e. projection between upper and lower benchmarks) would get their projections as base assumption for price control, with:
    - o excess funded as overspend where efficient; and
    - o savings rewarded at return; and
- ♦ low forecasters (i.e. projection below lower benchmark) would get the lower limit as base assumption for price control, with:
    - o excess (above that lower benchmark) funded as overspend where efficient; and
    - o savings (below the benchmark, rather than the company's original projection) rewarded at return plus depreciation.

[1] From table 3.1 of the final proposals

36. It is not immediately clear whether this offers significant advantages to the pure scheme, although it does make it less stark and gives the option of linking base funding more closely to submissions. This is consistent with our repeated point that benchmarking should not be used as the sole determinant of allowed income.

37. We recognise a risk that, if these proposals were carried forward for the next price control, there would be an inappropriate incentive for distributors to pitch their forecasts near the upper benchmark. This issue is eased by the proposal that distributors in the middle band would receive only return on all their efficiencies, even if this took their out-turn expenditure below the lower benchmark.

38. The above approach also introduces the (almost certainly unwanted) prospect of two companies making almost identical submissions, but resulting in very different incentives. This might occur where two companies' submission straddled the lower benchmark: the higher could only ever earn return on its savings, while the lower would always earn return plus depreciation. Hence, it seems desirable to consider modifications that are result in the treatment of a company being more influenced by out-turn investment than by initial forecast, without going so far as to lose the incentive to make reasonable forecasts.

39. An alternative that yields similar outcomes in terms of encouraging reasonable forecasts, without the distortions discussed above, blends the two incentive rates (i.e. return only and return plus depreciation) so as to reward efficiencies at return only until they equate to (say) twice the difference between projection and lower benchmark, then allow return plus depreciation thereafter. This reduces the boundary issues between bands, and provides yet further incentive for companies to set reasonable forecasts in the expectation of being near the lower benchmark.

40. Further, the benchmarks could be set by reference to companies' submissions, e.g. by using upper and lower quartile values for the upper and lower benchmarks. This should encourage companies to submit realistic forecasts lest they are exposed by the rest of the sector.

41. There is no meaningful incentive to submit a ridiculously low forecast in the expectation of being in the most favourable band. The lower benchmark would then be set by one or two other companies. At best, these would be realistic but might be too low for the genuine capital requirements of the subject distributor. At worst, those other distributors might also have decided to attempt to game the system, and all would receive insufficient allowances. That is, gaming in an attempt to earn the rewards of the lower band is more likely to result in a distributor being forced into overspend against the benchmark.

42. There will always remain the issue that distributors may choose to tailor their forecasts to their view of the likely benchmark. This is no greater under these proposals than where we use the PBP models: indeed, using other distributor's forecasts as part of the benchmarking reduces the value of gaming.

43. If companies' own forecasts have influenced the allowances, it would be inappropriate to reward companies according to the quantum (rather than the proportion) of efficiencies made, so the rewards available under the incentive should be modified according to the size of the original programme. That is, companies whose forecasts have led Ofgem to allow a higher projected investment should expect to retain less benefit per pound saved than distributors with more modest plans.

44. The proposals outlined above go some way to achieve this, since companies with lower projections can more easily access higher returns. As these higher percentage returns would be on a smaller capital sum (i.e. the lower submission), proportionality is retained.

worked example

45. Ofgem could take any reasonable approach to establishing the benchmark. We suggest that the characteristics of a virtuous scheme, taking as read (in this particular paper) that the general case for rising investment is accepted across the board, are that it:

   - ensures that all levels of expenditure, i.e. all combinations of forecast and out-turn, secure at least the funding that would have been allowed had the price control process been perfect;
   - avoids requiring customers to fund the higher levels of projected investment without some demonstration of the requirement;
   - provides incentives to efficiency for all companies;
   - rewards companies both for submitting more reasonable projections and for delivering efficiencies; and
   - provides a balance between rewards under the scheme for low projections and implicit contingencies in higher submissions

46. The following working illustrates an approach where:

   - high forecasters (i.e. projection above upper benchmark) would get the upper limit as base assumption for price control, with:
     - overspend funded at return plus depreciation, subject to an efficiency test, in a similar approach to that proposed in the open letter on gas distribution price controls; and
     - savings (below the benchmark, rather than the original projection) rewarded at return, until savings equate to twice the gap between upper and lower benchmark, and rewarded at return plus depreciation for further efficiencies;
   - medium forecasters (i.e. projection between upper and lower benchmarks) would get their projections as base assumption for price control, with:
     - excess funded as overspend where efficient; and
     - savings rewarded at return, until savings equate to twice the gap between projection and lower benchmark, and rewarded at return plus depreciation for further efficiencies; and
   - low forecasters (i.e. projection below lower benchmark) would get the lower limit as base assumption for price control, with:
     - excess (above that lower benchmark) funded as overspend where efficient; and
     - savings (below the benchmark, rather than the company's original projection) rewarded at return plus depreciation.

47. In turn, it assumes a benchmark for each distributor that combines:
    - percentage change in investment from one period to the next; and
    - projected investment per customer.
48. From the summary of distributors' forecasts published by Ofgem in March 2004, we can take investment projected for the current (2000-05) and coming (2005-10) periods. These yield projected step changes from one period to the next, that we can express as a percentage: we can then assess upper and lower quartile step changes across the sector. Similarly, we can assess upper and lower quartile investment per customer.
49. This is shown by the table below. The Scottish distributors have been omitted simply because of the potential distortion of the treatment of 132 kV assets on average costs (although this could readily be resolved were these proposals rather than an example):

	£/customer 2000-05	£/customer 2005-10	% step
EdF: Eastern	185.2	323.5	75%
EdF: Seeboard	196.2	317.8	62%
EdF: London	197.1	382.3	94%
SP: Manweb	290.3	425.3	46%
CN: East Midlands	159.7	299.8	88%
CN: Midlands	202.8	332.2	64%
UU: Norweb	246.0	302.0	23%
SSE: Southern	182.6	269.8	48%
WPD: Swalec	216.2	218.9	1%
WPD: Sweb	218.3	271.7	24%
CE: Yorkshire	177.5	229.9	30%
CE: Northern	188.9	226.2	20%
Lower quartile		259.8	24%
Upper quartile		325.7	67%

50. For the purposes of this exercise, we can derive benchmarks from this in two ways:
    - simple £/customer; and
    - applying a benchmark step change from one period to the next to the individual expenditure in the current period. That is, we accept that expenditure in the current period is reasonable, and apply what we deem to be a reasonable increase from that level.

51. Having upper and lower quartile values for both £/customer and step change allows us to derive upper and lower benchmarks for each distributor. At the risk of stating the obvious, the £/customer benchmark will not vary between distributors, as this is common across the sector, but the benchmark derived from step change will be specific, as it applies a common percentage to individual investment levels.

52. In this example, we have created a hybrid benchmark by taking an arbitrary 75:25 blend of the £/customer and step change benchmarks. This gives results we can first express in terms of £/customer and as a proportion of companies' own projections:

	distributors' projections (£/customer)	lower benchmark (£/customer)	upper benchmark (£/customer)	lower benchmark (% projection)	upper benchmark (% projection)
EdF: London	382.3	256.0	326.3	67%	85%
SP: Manweb	425.3	284.9	365.2	67%	86%
CN: Midlands	332.2	257.7	328.7	78%	99%
EdF: Eastern	323.5	252.3	321.4	78%	99%
EdF: Seeboard	317.8	255.7	326.0	80%	103%
CN: East Midlands	299.8	244.4	310.8	82%	104%
UU: Norweb	302.0	271.1	346.7	90%	115%
SSE: Southern	269.8	251.5	320.3	93%	119%
WPD: Sweb	271.7	262.6	335.2	97%	123%
CE: Yorkshire	229.9	249.9	318.2	109%	138%
CE: Northern	226.2	253.4	323.0	112%	143%
WPD: Swalec	218.9	261.9	334.3	120%	153%

53. This provides a purely illustrative view of how distributors might be divided into three groups of:

- high forecasters, whose projections are above the higher benchmark (i.e., in the form of the table above, the higher benchmark is less than the distributor's projection);
- medium forecasters, whose projections are between the benchmarks (i.e., in the form of the table above, the higher benchmark is greater than the distributor's projection and the lower is less); and
- low forecasters, whose projections are below the lower benchmark (i.e., in the form of the table above, the lower benchmark is greater than the distributor's projection).

54. For illustrative purposes only, three distributors have been selected to illustrate the three levels of projected expenditure, specifically Manweb (high), Southern (medium) and Northern (low). These specific assessments take three levels of potential out-turn investment, expressed as a percentage of forecast, for each of these distributors, to show what proportion of such investment would fall to be remunerated under each element of the proposed capital funding scheme:

	distributor's projection (£/customer)	lower benchmark (£/customer)	upper benchmark (£/customer)	lower benchmark (% projection)	upper benchmark (% projection)
Manweb	425.3	284.9	365.2	67%	86%
Southern	269.8	251.5	320.3	93%	119%
Northern	226.2	253.4	323.0	112%	143%

Manweb

	funding (as proportion of distributor's projection)			
Out-turn vs. distributor's projection	overspend	Normal	return	return plus depreciation
115%	29%	86%		
100%	14%	86%		
85%		85%	1%	

Southern

	funding (as proportion of distributor's projection)			
Out-turn vs. distributor's projection	overspend	Normal	return	return plus depreciation
115%	15%	100%		
100%		100%		
85%		85%	14%	1%

Northern

	funding (as proportion of distributor's projection)			
Out-turn vs. distributor's projection	overspend	Normal	return	return plus depreciation
115%	3%	112%		
100%		100%		12%
85%		85%		27%

55. These examples support our contention for these proposals, that they provide sufficient funding for all levels of expenditure, with incentives to efficiency.
56. This makes no value judgement of Manweb's proposals; it suggests that we might be satisfied only that customers should fund 86% of that distributor's projections up front and, if Manweb are right, they will be no worse off than if their allowed income had been based on a perfect forecast. This proposals ensure that all efficiently-incurred expenditure is fully funded: the only difference between categories is the test applied.
57. Similarly, it provides scope for all distributors to earn some rewards for capital efficiency, within a zone of reasonableness. The additional rewards available to low forecasters are no different to those explicitly made available to Sweb and Swalec at the last review.
58. The example provided is intended to illustrate the proposal and does not, admittedly, incorporate all of the necessary fine tuning that would be appropriate were this to be carried forward as a strong possibility. That said, we do not consider these adjustments to be particularly difficult, they would merely need to be considered carefully to ensure that the outcome produced a balanced result across the industry.