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9 August 2004

Dear Cemil,

ELECTRICITY DISTRIBUTION PRICE CONTROL REVIEW:
INITIAL PROPOSALS – JUNE 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 in the attached represent the response of CE, NEDL and YEDL to Ofgem's publication, '*Electricity Distribution Price Control Review: Initial Proposals, June 2004*' (the *Initial proposals)* and to the following associated documents:

- *'Further details on the incentive schemes for distributed generation, innovation funding and registered power zones';*
- *'Distributed generation, innovation funding incentive and registered power zones – Regulatory Instructions and Guidance, Version 1';*
- *'The losses incentive and quality of service'; and*
- *'Structure and scope of price control licence modifications'.*

Our full response comprises this letter together with an executive summary and point-by-point enlargement that are provided as attachments. We have also written to Ofgem separately setting out our detailed views and requirements on all of the key areas outlined above.

Our shareholders view the *Initial proposals* as unacceptable and ratings agencies and investors have singled out CE for a negative outlook. We have demonstrated that we are efficient, top performers on quality of service and other non-financial key indicators and that we are reasonable forecasters. However, the total income for the next price control period represented by the *Initial proposals* shows a significant shortfall against our forecast submission. There are some significant issues affecting all DNOs. We also believe that we have been relatively disadvantaged and this has led to the CE companies receiving the most severe indicative Po cuts.

Our key concerns are outlined below:

- **pension funding** - the customer contribution towards early retirement deficiency costs (ERDCs) should be at least 82% and the annual cost calculated on an NPV basis. In addition the distribution element of the deficit should be at least 92.5 per cent for NEDL. For all companies, ongoing pension costs should be set in line with latest actuarial valuations.

- **relativity** - there should be recognition of CE's excellent performance relative to other companies. We have set the standards for capital forecasting, are upper-quartile on operating costs and leading performers in the areas of safety, customer service and the environment. We expect to see financial recognition for setting the standard in all these areas (similar to that awarded to WPD).

- **cost of capital** - there is no justification for a base cost of capital below that proposed by Ofwat for the water industry. Only a cost of capital at the top end of the range will meet city expectations.

- **operating costs** - we have been judged as efficient with strong non-financial performance by Ofgem and its consultants and thus our forecasts should be allowed in full. An increase in allowances for storms and atypical costs, a non-operational capex adjustment for YEDL, a reduced weighting to circuit length and a revised figure for YEDL in the CSV variable are required. In addition there should be no dilution of overall incentives for top performers.

- **future productivity gains** - it is unacceptable that Ofgem should deny the CE companies the costs projected in the forecast business plan questionnaires (FBPQs) submitted to Ofgem. Productivity assumptions derived from total factor productivity analysis cannot reasonably be used in substitution for the costs that have been included in the FBPQs.

- **capital expenditure** - we have set the standard in terms of capital forecasting and our capital projections have not been criticised – our plans should be allowed in full and rewarded. Overhead apportionment requires review and quality of supply (QoS) capex should be increased by a moderate amount.

- **total cost planning** - overall there has been insufficient focus on our forecasts which Ofgem's consultants have largely deemed as efficient. Our forecasts represent a coherent balance between opex and capex elements – our efficient trade-offs have not been recognised in setting allowances. Specifically tree cutting and fault management cost allowances need to be substantially increased.

- **capital sliding scale** - we strongly support the sliding scale mechanism but believe that it needs to be strengthened to ensure equitable treatment of reasonable forecasters. Top performers should be allowed an incentive rate of 65%, an additional return of 0.3% and a capital allowance equal to 110% of benchmark.

- **RAV roll-forward** - we expect Ofgem to propose an approach to RAV roll forward that is fair between companies and does not leave the CE companies disadvantaged by their transparent approach to the provision of information at the last price control review and their treatment of costs since then.

- **tax calculation** - the *Initial proposals* understate the tax due. This position must be corrected.

- **financial modelling and indicators** - our analysis of the *Initial proposals* indicates, based solely on the Ofgem forecasts, that equity cashflows will be restricted over the DPCR4 period. This conflicts with the gearing and cost of capital assumptions made by Ofgem and indicates that the overall return is inadequate.

On metering, the information in the *Initial proposals* falls short, both in terms of detail and quality, of enabling companies to validate and challenge the scope and form of the control. We urge Ofgem to work openly with companies to get to a much higher level of detail as rapidly as possible.

The *Initial proposals* would not be a satisfactory basis for a price control settlement for the CE companies. We remain committed to working with Ofgem with the aim of resolving the issues we have outlined.

Yours sincerely

John France

John France
Director of Regulation

ELECTRICITY DISTRIBUTION PRICE CONTROL REVIEW:

INITIAL PROPOSALS – JUNE 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:
Initial Proposals - June 2004

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

Set out below are the views of CE, NEDL and YEDL in response to Ofgem's publication *Electricity Distribution Price Control: Initial Proposals, June 2004* (the *Initial proposals*) and its associated publications: *Further details on the incentive schemes for distributed generation, innovation funding and registered power zones; Distributed generation, innovation funding incentive and registered power zones – Regulatory Instructions and Guidance, Version 1; The losses incentive and quality of service;* and *Structure and scope of price control licence modifications*. The response broadly follows the form of the *Initial proposals*, as most of the associated documents fit readily into that form, and is provided as an executive summary followed by a point-by-point enlargement.

EXECUTIVE SUMMARY

Form, structure and scope of price controls

- ***Price index:*** We agree with the decision to retain the RPI – X regulatory framework rather than changing to CPI – X.
- ***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 are encouraged by Ofgem's view that these costs should be a pass-through item. Whilst we believe that these costs are not strictly within our control, we also believe that we have done our best in our dealings with the Valuations Office Agency (VOA) to keep them as low as possible.
- ***Dealing with uncertainty:*** We support Ofgem's proposal to commit to re-open the price control to consider the costs arising from the impact of the Traffic Management Act and the Electricity Safety, Quality and Continuity Regulations (ESQCR). We also agree that, if the requirements become reasonably certain, cost allowances should be set at the 'efficient level' rather than 'pass-through': this will provide companies with appropriate efficiency incentives. However, we do not feel that Ofgem's proposals go far enough to deal with uncertainties which have not yet currently materialised but which may arise during the next price control period due to relevant and material changes in legislation.

We therefore continue to advocate 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, and covered by subsequent letters and discussions.

- ***Definition of costs and impact on incentives:*** Under the *Initial proposals*, the maximum benefits retention for out-performance would become capped at 40 per cent for all classes of expenditure. We strongly believe that the proposal to equalise incentives between opex and capex should not result in a dilution of the incentive power of the overall incentive package relative to the current regime for reasonable forecasters and leading performers. Ofgem has indicated that if clear boundaries between opex and capex can be defined and enforced, then Ofgem will review whether differential incentives are appropriate and whether incentives can be strengthened during the price control period. We are willing to agree a set of cost definitions and believe that we should not suffer reduced incentives as a result of such a lowest common denominator approach. We would advocate rewarding the good forecasters by increasing the benefits retention from 40 per cent to 65 per cent. This would restore overall incentive rates on opex and capex for top performers to current levels – differentiation in rates should be retained drawing the poorer performers above the proposed 23 per cent incentive rate, which may be too severe. If incentives are not strengthened then a higher cost of capital is required. Finally, our track record of sensible forecasts and open disclosure on cost allocation disadvantaged us at DPCR3 and amendments to the regulatory asset value (RAV) are required to correct this at DPCR4.
- ***Rolling capex incentive:*** We continue to support strongly the retention of both the depreciation and return benefits for savings achieved during the post-DPCR3 price control period.
- ***Losses incentive:*** We are supportive of the proposed simplification of the losses incentive mechanism and the methodology proposed to support it.
- ***Metering price control:*** Overall, we are concerned at the slow pace of progress on the development of the metering price control. The *Initial proposals* represent the first sight of Ofgem's thinking on the form of this new control. As such the information presented falls short, both in terms of detail and quality, of enabling companies to validate and challenge the scope and form of the control. We urge Ofgem to work openly with companies to get to a much higher level of detail as rapidly as possible. We have several concerns in respect of the development of the metering price control. Firstly,

progress on arriving at a robust definition of the control continues to be significantly slower than the work on the main control, giving rise to significant uncertainty and diminishing companies' ability to validate, challenge or plan for the implementation of the new control in a timely manner. Secondly, the data that has been published appears to be erroneous and does not reflect the full scope of the proposed control. Finally, we do not agree that using metering points is an appropriate revenue driver for the meter operation (MOp) activity – the number of visits is a far more cost-reflective driver.

Quality of service and other outputs

- ***Quality of supply plans:*** We submitted an investment plan that we believe would deliver performance improvements to customers at one quarter of the price that the customer survey indicates they would be willing to pay - a plan that particularly focused on targeting an improvement in the rural areas. Ofgem has sensibly started to recognise the trade-off between opex and capex considerations for quality of supply (QoS) performance. We are not fully convinced that cost / performance trade-offs have been optimised for all companies and believe that a modest increase in QoS capex is required.

- ***IIP target setting:*** We generally support the use of the disaggregation process to inform the IIP CI and CML targets. However, there are four issues that need to be addressed with regard to the setting of targets:

  - the inclusion of unit-protected circuits in the HV benchmark;
  - the forward projection of planned interruptions;
  - the over-reliance on CML per CI in setting the CML benchmark; and
  - cost/performance trade-offs.

- ***IIP exclusions:*** We support the exclusion of exceptional events from the IIP scheme but believe that in order to ensure equity it is necessary to allow distribution network operators (DNOs) to exclude the effect of any weather-related event that breeches the event threshold in any other DNO, whether or not the thresholds are breeched for that particular DNOs network.

Distributed generation

- ***Incentive rate for the hybrid scheme:*** We generally support the proposals but still consider the incremental rate of £1.5/kW to be too low to create real incentives.

- ***Incentives for network access:*** We consider it inappropriate to introduce the unavailability penalty scheme. Such arrangements should be introduced only on a contractual basis with particular generators that pay for a firm supply.

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. We contend that NEDL and YEDL are leading performers on cost efficiency whilst also being excellent all-round performers on customer service, quality of supply, safety and the environment. It is important that these performance aspects are considered, in addition to cost, when assessing efficiency.
- ***Capex/opex trade-offs:*** These clearly exist, but have not been recognised in the *Initial proposals*. Ofgem is at risk of cherry-picking low opex from high-capex companies and low capex from high-opex companies. Amongst other tools, we believe that Ofgem should continue with total cost analysis and provide some form of shading allowance to reflect total cost and capital efficiency. Two key examples for CE relate to tree cutting and fault management.
- ***Storms and atypical costs:*** The proposed allowances for storms, insurance and atypical costs are not adequate and do not reflect the costs incurred by YEDL in the current price control period. We propose an atypical allowance of at least £2m per annum per licensee to cover storms and insurance costs, including the new payment arrangements for customers. This comprises £1.1m per annum for insurance and £0.9m for a weather-related incident each year. Actual insurance costs in 2003/04 were £1.4m per annum for YEDL.
- ***Non-operational capex:*** It is unreasonable that no normalisation adjustment is made to YEDL for non-operational capex. With respect to non-operational capex, YEDL's position may be unique as it has assets in both the licence holder and the service provider. The use of forecast non-operational capex in the regression does not provide a consistent treatment for all companies. To correct this, there should be a normalisation adjustment for YEDL of £3.6m (based on the industry and YEDL five year average) prior to regression analysis.
- ***Benchmarking techniques:*** If regression is to be used as part of the operating cost assessment process, we consider an ordinary least squares (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). Ofgem, in our view, correctly states that it would be inappropriate to benchmark against a single frontier or outlier company and we therefore see merit in the use of the upper quartile in the overall methodology chosen by Ofgem. However, in a period of diminishing opportunities for out-performance an OLS approach would provide a better balance of incentives because it allows 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 improved the data set, we are not confident that the results of that, or the accuracy and consistency of certain elements of the CSV data, can currently justify a benchmark other than the average. We are therefore extremely concerned that Ofgem has used an upper quartile basis and then, on top of this, has assumed a two per cent per annum frontier shift. Incentive regulation should not seek to remove the savings from efficient companies before the savings have been made.

- ***Composite Scale Variable (CSV):*** We have set out in separate papers and discussions with Ofgem our views on the composition of the CSV. We do not believe that Ofgem has made a sufficient case to move from the DPCR3 weightings (i.e. 50 per cent customer numbers, 25 per cent units and 25 per cent circuit km) to a weighting of 50 per cent for circuit length. On a point of detail, we require that Ofgem use the value of 56,483km for the YEDL circuit length.
- ***Future opex efficiency expectations:*** It is unacceptable that Ofgem should deny the CE companies the costs projected in the forecast business plan questionnaires (FBPQs) submitted to Ofgem. Productivity assumptions derived from total factor productivity analysis cannot reasonably be used in substitution for the costs that have been included in the FBPQs. There is no compelling case for regulators to attempt to anticipate future efficiencies by applying an ongoing improvement expectation to any derived benchmark, particularly as future efficiency savings are proving harder to achieve. However, we note that Ofwat, in its recent determinations[1], expects the water service companies to achieve continued annual efficiencies of only 0.3 per cent, which is half of what Ofwat's considers to be the total scope of efficiencies available to these companies. Ofwat goes on to say that it is necessary to have an appropriate balance between incentives efficiency assumptions included in the price limits and that including the whole of the scope for improvements in the price limits would not provide companies with any incentive to

outperform. We strongly oppose Ofgem's proposed two per cent per annum shift of the operating cost benchmark. This is an unreasonable expectation for a business providing high levels of service that is close to the efficiency frontier. The incentive properties of RPI-X regulation will bring forward any efficiency projects that yield a positive net present value (NPV). Companies should not be expected to pass on all the benefits from these savings to customers before the savings have been made. The retail price index (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 improve significantly upon the efficiency gains in the economy as a whole. CE forecasts a one per cent per annum improvement in Repairs and Maintenance (R&M) costs beyond our efficient 2002/03 costs. Both NEDL and YEDL have also been shown to be upper quartile in respect of operating costs and Ernst & Young, in their report, state that 'Ernst & Young's view of CE is that it is a well-run, efficient company, and that the scope for further efficiencies is limited'. We therefore have serious concerns regarding the allowances which result from Ofgem's analysis and which are published in the *Initial proposals*. We do not believe a two per cent shift in total controllable costs to be credible or justified.

- ***Mergers:*** We agree with Ofgem's statement that it is not necessary to adjust DNOs' costs for merger savings for the purpose of benchmarking.
- ***Review of capital forecasts:*** Our capital allowances should be increased since our forecasts have been largely deemed as efficient yet have not been allowed in full. Our capital forecast should be allowed in full – the £20m for YEDL should be reinstated as both disallowed items are within the range of discretion. Overhead apportionment also requires review and QoS capex should be increased.
- ***Sliding scale incentive mechanism:*** Capital efficiency based on reasonable forecasts should be strongly rewarded, and we support the sliding scale mechanism proposed by Ofgem, which provides greater returns to companies that have submitted reasonable forecasts and then either meet or beat those forecasts. However, the proposals do not go far enough in reducing discrepancies between companies. The PB Power method appears to systematically derive low benchmarks where companies have forecast most efficiently. The PB Power benchmarks should be increased or allowed capex set with increased headroom above the PB Power value – we suggest 110 per cent for top performers. This is supported by allowed income per customer, which is diverging across licensees. Ofgem should restore overall incentive rates on opex and capex for

[1] Future water and sewerage charges 2005-10, draft determinations, 5 August 2004

top performers to current levels – differentiation in rates should be retained drawing the poorer performers above the proposed 23 per cent incentive rate, which may be too severe. If incentives are not strengthened then a higher cost of capital is required. The transfer of costs (elements of faults, non-operational capex and overheads) from the 'expensed' to the 'depreciated' category would increase the risks that the costs might not be recovered and this should also be recognised through an increase in the cost of capital. The additional 0.2 per cent return to reward companies that choose the lowest allowance is too small and is much lower than the WPD reward for quality of supply – it needs to be increased to 0.3 per cent to equalise the values.

- ***Treatment of overheads:*** We welcome Ofgem's attempts to ensure recovery of the full value of overheads transferred out of operating costs and into the capital analysis. However, there are a number of oversights in the *Initial proposals*, in that; overheads are attributed to faults; faults are combined with operating costs; overheads are transferred out of this sub-total, and the remaining figure is subject to regression. 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. In the current analysis, we have been effectively disallowed a proportion of overhead costs as a result of errors in the attribution of overheads to differing capex categories. An adjustment needs to be made to restore this amount.

- ***RAV roll-forward:*** We consider that the adjustments to the regulatory asset value (RAV) for NEDL and YEDL set out in the *Initial proposals*, in respect of fault cost capitalisation, represent a reasonable attempt to treat these licensees fairly, compared with companies that were capitalising faults at DPCR3 and whose operating costs were used to determine DPCR3 opex allowances. Further adjustments are also required in respect of the capitalisation of overheads from 1998/99to 2004/05.

  A pragmatic solution to adjusting for overheads is to utilise the normalised 2002/03 data and adjust the opening RAVs of companies to reflect the industry average capitalisation of overheads. This should be done for the full period from 2000/01 to 2004/05.

  The adjustment for faults should correct for inequity in RAV values and ensure that consistency across the sector is achieved.

Relative treatment

- The *Initial proposals* identify the following companies as upper quartile cost performers in terms of the efficiency frontier: SSE Southern, SSE-Hydro, CE- NEDL, CE-YEDL and

WPD-S Wales. They are also recognised as quality performers in certain dimensions. However, CE is the only company not to have been rewarded in recognition of being an upper quartile quality performer. With strong all-round class-leading performance in a significant number of areas, it is unreasonable that YEDL and NEDL have not been provided with additional allowance in the same manner as our peers. We therefore invite Ofgem to discuss its underlying logic for providing additional rewards and seek confirmation that the all-round performance of CE, combined with costs at the upper quartile, will be recognised in Ofgem's future proposals.

Financial issues

Cost of capital

- We request that Ofgem provide an updated preliminary view of the cost of capital in their September paper so that we can properly assess the financeability and cash flows of our business.

- We are concerned that the *Initial proposals* understate the tax due. This should be corrected.

- The Ofwat Draft Determinations published on 5 August 2004[2] indicate a cost of capital of 5.1 per cent on a real, post-tax basis. Allowing for the different gearing assumptions this equates to a Vanilla WACC of 5.66 per cent. We do not see any rationale for Ofgem proposing a lower cost of capital. We suggest that only a cost of capital at the top end of the Ofgem range would meet city expectations and be similar to the calculations being applied to the water industry.

- The water industry is not the only benchmark; we have previously indicated that there are a number of other comparators including the output of the NERA work, European utility returns and city expectations of the total regulatory return in a regime which has reduced out-performance incentives. These issues are further explored in the ENA letter, 'Weighted Average Cost of Capital', dated 23 July 2004.

- The allowance for debt finance needs to allow for the prospect of increasing rates over the next review period as well as being adjusted to reflect the efficient debt financing undertaken in previous periods.

- A higher cost of capital is supported by the need to reflect the higher risk (and smaller returns) brought about by the proposals, which diminish opportunities for out-performance whilst weakening the rewards. At the same time significant elements of costs have been moved from the ‘expensed’ to the ‘depreciated’ category.

Pensions

- Our concerns with regard to pensions relate to the allocation between price-controlled and non-price controlled activities, the cost allowance for ongoing pension costs and the treatment of early retirement deficiency costs (ERDCs) and the calculation of the annual cost on an NPV basis.
- We appreciate Ofgem’s recognition that the distribution element of the deficit is 100 per cent for YEDL but contend that the figure for NEDL should be at least ***92.5*** per cent and not the 80 per cent quoted in the *Initial proposals*.
- We believe that the allowance for ongoing pension costs should be set at ***20.4*** per cent of pensionable salaries, in line with the latest actuarial calculation, rather than the 15 per cent proposed by Ofgem.
- We are encouraged that Ofgem sees the merit of the argument that customers should pay for at least 70 per cent of the ERDCs because they received the benefits of the resulting efficiencies. We actually believe the proportion of the benefit of efficiencies that accrues to customers to be at least 82 per cent: this would imply disallowance of up to ***18*** per cent of the ERDCs, because efficiencies are not all made at the beginning of the price control period.

Tax

- We have been unable to replicate the tax calculations presented in the *Initial proposals. We* therefore expect further discussion on this element of the proposals during the review of Ofgem’s financial model.

Financial modelling and indicators

- Our shareholders’ view, that the *Initial proposals* are unduly harsh on CE, is echoed by the City. Standard & Poor’s (S&P) found the proposals generally neutral but singled out CE as being outside their assumptions. Barclay’s Capital Research advised that NEDL and YEDL should be avoided as ‘broadly illiquid’ and highlighted the possibility of a ‘downgrade across the group’.

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[2] Future water and sewerage charges 2005-2010, Draft Determinations, Summary, Ofwat, 5 August 2004

- There is no reason why this price control review should result in issues with rating agencies and debt holders and we could not be expected to accept such an outcome.
- 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.
- We are currently reviewing Ofgem's financial model, which we received on 30 July. We will respond separately on any specific issues that arise as a result of that review. Our analysis of the Initial proposals indicates, based solely on the Ofgem forecasts, that equity cash flows will be restricted over the DPCR4 period. This conflicts with the gearing and cost of capital assumptions made by Ofgem and indicates that the overall level of return is inadequate.

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ELECTRICITY DISTRIBUTION PRICE CONTROL:

Initial Proposals – June 2004

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

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Ofgem asks, in the draft regulatory impact assessment (RIA), whether the Initial proposals represent an appropriate balance of measures to provide sufficient income / incentives for companies to deliver the required outputs. We do not believe that the *Initial Proposals* do strike the right balance, as discussed at meetings with the sub-committee of the Authority and with David Gray and Martin Crouch, and we look to Ofgem to act upon our observations in its preparation of the updated proposals.

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

1.1 SCOPE OF THE PRICE CONTROL

1.1.1 Revenue drivers

(Paragraphs 3.6 to 3.7)

1. We support the decision to retain the 50:50 split between customer numbers and units distributed and to use the same customer numbers definition as for the Information and Incentives Project (IIP).

2. We also support Ofgem's revised weighting within LV and HV voltage categories.

3. We agree with the proposals that EHV charges should be included 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.

4. We agree that there should be no volume driver attached to EHV revenues.

1.1.2 Price index

(Paragraph 3.10)

5. We support Ofgem's decision to retain RPI (rather than CPI) as the relevant index within the regulatory framework

1.1.3 Units distributed out of area

(Paragraph 3.14)

6. We agree that DNOs that distribute out of area should be treated the same as Independent Distribution Network Operators (IDNOs) and that any revenue associated with distributing units out of area should be treated as an excluded service item.

7. We also continue to agree that the costs associated with wheeling charges should continue to be pass-through costs and that the revenues associated with wheeled units should be included within the price control.

1.1.4 Non-contestable connection charges

(Paragraph 3.15)

8. We agree with the proposal to develop standards of performance for new connections, as discussed in the recent consultation, 'Competition in connections to electricity distribution systems' (Ofgem 124/04a).

1.1.5 Other excluded services

9. We agree with the proposals not to change the arrangements for top-up and standby charges, non-trading rechargeable costs and other minor activities and charges; and to include units distributed to networks embedded within DNO networks within the scope of the price control.

1.1.6 Business rates

(Paragraph 3.17)

10. We appreciate Ofgem's recognition that DNOs have actively engaged with the VOA and the Scottish Assessors Association (SAA) in the valuation process in order to obtain the best deal for electricity customers and welcome Ofgem's current view that there should be no disallowance of any rates costs. We believe that the VOA proposals in respect of NEDL and YEDL would be unlikely to be improved upon by an appeal. We request that Ofgem let us know if it has a different view.

1.1.7 Revenue protection

(Paragraph 3.19)

11. Revenue protection costs should be excluded on the basis that:

- revenue protection is a service provided by companies outside their own licence obligations (those obligations being part of the supply licence); and

- the inclusion of revenue protection within the distribution price control would significantly weaken the incentive for companies to adopt a proactive attitude to the management of losses and energy efficiency, in its broadest sense.

1.2. INCENTIVE FRAMEWORK

1.2.1 Allocation of costs for the incentive mechanism

(Paragraph 3.26)

11. The *Initial proposals* state that Ofgem proposes to treat all costs on the same basis for determining the proportion of efficiency savings that will be retained by shareholders. Ofgem's intention is that incentives for all categories of efficiency savings will be equalised, but that it will review whether differential incentives may be re-introduced after further work is undertaken, during the next price control period, to develop more robust capex/opex boundaries and reporting arrangements. However, it is not yet clear from the *Initial proposals* how Ofgem will achieve this.

12. However, there are two key issues arising from the proposals:

- the transfer of costs from the 'expensed' to the 'depreciated' category would increase the risk that the costs might not be recovered and this should be recognised through an increase in the cost of capital; and

- the overall weakening of incentives would dilute the returns that investors could expect to receive from DNOs and this should also be addressed in the cost of capital.

13. If Ofgem moves a significant set of costs from the category that is remunerated within the year to the category that is remunerated over a much longer period, then the risk attaching to those costs has increased if they are then subject to a twenty-year recovery period. That period encompasses probably four regulatory reviews and at least four general elections. The balance of the overall regulatory settlement would

surely have changed if a large component of costs were moved from the ‘expensed’ to the ‘depreciated’ category. Ofgem’s proposed change to the cost of capital (6.5 to 6.8 per cent in our case) does not include any adjustment for the move from an ‘expensed’ to a ‘depreciated’ treatment of these costs.

14. Looking at the weakening of incentives, investors do not acquire distribution businesses because they expect, and will be satisfied with, the bare regulatory cost of capital (at DPCR3 the 6.5 per cent, pre tax, real, assumed by Ofgem). The regulatory cost of capital is only part of the overall return that the investor is taking into account when he contemplates an acquisition. He also makes assumptions about the extent to which the licensee will be able to out-perform the regulator’s assumed cost of capital. These two components – the regulatory cost of capital and the additional return from out-performance – together comprise the investor’s expected return and this calculus determines the transaction value of a DNO.

15. However, it remains true that the marginal return that the investor will make on a marginal investment (for example in new distribution assets) will never exceed the regulatory cost of capital, because this is the investment that enters the RAV and on which the regulatory return is allowed.

16. In the past the out-performance regime for opex was £1 in the £. The *Initial proposals* state that the capex and opex out-performance regimes will be equalised and, since our capex out-performance regime is determined in the *Initial proposals* to be 40p in the £, it follows that our opex out-performance regime would also be 40p in the £ (although nowhere does Ofgem actually state this conclusion).

17. Whereas the investor previously had a component of costs from which he might derive 100 per cent out-performance rewards, this has now been reduced to 40 per cent and the result is that the investor is driven back towards the bare regulatory return. The investor’s legitimate expectations of the potential to supplement the bare regulatory return with out-performance has been adversely affected by the move from an opex out-performance regime to a capex out-performance regime.

18. It also follows that the bigger the proportion of our costs that is remunerated over twenty years (rather than remunerated as expensed in the year), as a result of the equalization of incentives, the more DNOs will be driven down to the bare regulatory cost of capital. Therefore, if Ofgem is to equalise incentives, such a change must

involve the selection of a period over which the money is to be received that ensures that the overall balance is maintained.

19. Even if the cost of capital assumed by the regulator equated to the true cost of capital of the company (which we would argue it does not, and never did), the erosion of out-performance rewards would still be unacceptable and unfair because transactions would have taken place in a world in which such significant changes to the incentive framework had not been signalled. Investors value businesses in relation to their projected cash flows – the move to a twenty-year life for a significant category of costs is NPV-neutral only in regulatory terms and, even then, it is neutral only if the regulatory cost of capital truly equals the company's real cost of capital.

20. Since the true cost of capital is higher than the regulatory assumption, the move towards a twenty-year cash recovery period is not NPV-neutral: it is wealth-destroying. It means that even more of shareholders' funds are tied up at an inadequate rate of return. This change is occurring at a time when earning the necessary out-performance rewards, from which the regulated cost of capital has always been cross-subsidised, is being made even more difficult and subject to higher risks.

21. We are willing to agree a set of cost definitions and should not suffer reduced incentives as a result of a lowest common denominator approach. We would advocate rewarding the good forecasters by increasing the benefits retention from 40 per cent to 65 per cent. This would restore overall incentive rates on opex and capex for top performers to current levels – differentiation in rates should be retained drawing the poorer performers above the proposed 23 per cent incentive rate, which may be too severe. If incentives are not strengthened then a higher cost of capital is required. The transfer of costs (elements of faults, non-operational capex and overheads) from the 'expensed' to the 'depreciated' category would increase the risks that the costs might not be recovered and this should also be recognised through an increase in the cost of capital. Our track record of sensible forecasts and open disclosure on cost allocation disadvantaged us at DPCR3 and corrections to the RAV are required to correct this at DPCR4.

1.2.2 Dealing with uncertainty

(Paragraphs 3.30 to 3.34)

22. It is clear that all DNOs are faced with future cost uncertainties that make it difficult to assess future income requirements with confidence. To cater for this uncertainty, we

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

23. We appreciate that Ofgem recognises the former requirements and is to give an undertaking to re-open the price controls for the specific cases of costs arising from the Traffic Management Act and costs arising from the ESQCR.

24. However, we continue to believe that DNOs require more formal protection against material obligations that are yet unknown and we continue to support the mechanism described in detail in the letter, dated 15 April 2004, to David Gray from the Energy Networks Association, and covered by subsequent letters and discussions.

1.2.3 Losses

(Paragraphs 3.35 to 3.45 + supplementary document)

25. We broadly support the mechanism proposed.

1.3 METERING

(Paragraphs 3.46 to 3.72)

26. Overall, we are concerned at the slow pace of progress on the development of the metering price control. The *Initial proposals* represent the first sight of Ofgem's thinking on the form of this new control. As such the information presented falls short, both in terms of detail and quality, of enabling companies to validate and challenge the scope and form of the control. We urge Ofgem to work openly with companies to get to a much higher level of detail as rapidly as possible.

27. In terms of the specifics within the *Initial proposals,* we agree with the proposal that the meter asset provision (MAP) price control should be based on a price cap. As summarised above, we have concerns over the data presented in the document; we are unable to replicate the methodology by which the values have been derived.

28. In terms of MOp we have concerns over the validity of using the number of meters provided as an appropriate revenue driver. The first concern is that such a driver would couple the allowed MOp revenue to the MAP (i.e. the provision of meter) market share, which appears to create a distortion in the relationship between these two distinct markets.

29. A further concern is that using *only* number of meters provided across the whole MOp market does not recognise the distinction between credit and prepayment metering installations. Whilst credit meters are, largely, of a fit-and-forget nature that would tend to indicate that number of meters provided would provide a reasonable driver, in the case of the prepayment market the same cannot be said. Prepayment installations are widely recognised as requiring a significantly higher number of visits due to the nature of the technology and the customers, which would not be accurately reflected by a number of meters driver.

30. If it is accepted that credit meters are fit-and-forget, it is clear that number of visits and number of meters broadly equate to one another. It would therefore seem appropriate, to eliminate the issue in prepayment, to adopt a number of visits driver across all metering systems.

1.4 OTHER PROPOSALS

1.4.1 Duration of the price control

(Paragraph 3.73)

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

1.4.2 Operating cost rolling adjustment

32. We support the principle of opex rolling adjustment and provided our detail comments on the mechanism in our response to the March *Policy document*

1.4.3 Rolling capex adjustment

Existing price control period

33. Ofgem confirmed in the March *Policy document* 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 support strongly the retention of both the depreciation and return benefits.

34. 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

35. We fully support Ofgem's move to a sliding-scale mechanism to determine the benefits retention percentage. However, we believe that the top figure should be higher than 40 per cent to reward companies that have forecast sensibly by allowing a retention figure higher than that available under the current mechanism. This would also go some way towards recognising the overall weakening of incentives that would have been brought about by the transfer of costs from the 'expensed' to the 'depreciated' category. Additionally, an increase in the cost of capital would be required to recognise the increased risk inherent in this transfer.

Non-operational capex

36. In our response to the March *Policy document, w*e agreed that, in the next price control period, non-operational capex should be treated as included in the RAV and depreciated over five years. We are therefore concerned about the validity of moving to a 20-year depreciation period for this category of expenditure.

37. With respect to non-operational capex YEDL's position may be unique as it has assets in both the licence holder and the service provider. It is unreasonable that no normalisation adjustment is made to YEDL for non-operational capex and the use of forecast non-operational capex in the regression does not provide a consistent treatment for all companies.

38. YEDL's non-operational capex forecast for the next period is zero but it has assets with lives greater than five years which will not be replaced over the next period for which there needs to be an appropriate non-operational allowance to smooth recovery of this expenditure over time and ensure equitable treatment relative to other companies.

39. If no non-operational allowance is included for YEDL it will be disadvantaged relative to companies that have transferred all assets into the service provider and are receiving all of their non-operational depreciation through the contract charge. The timing and extent of transfers to service providers will also result in inconsistent treatment between companies.

40. We believe that there should be a normalisation adjustment for YEDL of £3.6m (based on the industry and YEDL five year average) prior to regression analysis.

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

2.1 SUMMARY OF RESULTS FROM THE CONSUMER SURVEY

(Paragraphs 4.3 to 4.6)

41. We supported the consumer survey and agree that it is valuable to inform the priorities for the price control review. However, we do not agree with the conclusion that Ofgem has drawn from the results that the main requirements are for improvements in CML. Tables 19 and 20 are indicating that customers want to see a balanced improvement in both CI and CML.

42. Whereas we recognise Ofgem's concern that the 'willingness to pay' survey is indicating very much higher values than has previously been the case and that £20 per customer may be too high a value for improvements, the average of 65p per customer which the *Initial proposals* would actually allow for NEDL and YEDL seems too low in the light of the available evidence.

43. We note that the survey indicates that rural and urban customers are only willing to pay for improvements in performance that will benefit their own areas. In view of this, we appreciate that Ofgem may not wish to adopt proposals that are consistent with the company's proposed quality case that concentrated additional investment on rural networks. However, the 'Ofgem quality case', presented in the FBPQ, would deliver a low-cost balance of improvements in both CI and CML across both urban and rural networks, and would represent very good value for money if the costs were allowed. Although this would involve an average annual cost of £1 per customer to support it, it would deliver an aggregate of CI and CML improvements at the same cost per CI or CML as that allowed in the interim proposals.

2.2 REVENUE EXPOSURE TO QUALITY OF SERVICE INCENTIVES

(Paragraphs 4.7 to 4.8)

44. We support Ofgem's proposal to increase the focus on output performance by increasing the exposure to quality of service incentives. We also welcome the proposed move to a symmetrical scheme with rewards/penalties paid on an annual basis.

45. However, the overall proposals increase the downside to a cap of four per cent (plus Guaranteed Standards (GS) payments not associated with storms) whilst only

increasing the upside to 3.05 per cent. This is still asymmetric and represents an increase in risk that should be recognised in the calculation of the cost of capital.

2.3 STANDARDS OF PERFORMANCE

(Paragraphs 4.9 to 4.22)

46. As previously indicated to Ofgem, we support the proposal 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.

47. With regard to the making of penalty payments for failures against the standards, we support the proposal for semi-automatic payments. Ofgem is aware, from our previous responses, of the proactive stance taken by NEDL and YEDL in contacting customers to inform them of their right to compensation and of our preference to make payments direct to the customer wherever possible.

48. Although in practice we believe the likely impact to be small, we believe that, if companies take these proactive steps, it is not appropriate for Ofgem to impose a reduction in income equivalent to the number of customers who do not subsequently claim.

49. We support the proposal to retain the existing compensation arrangements for HV customers.

50. We do not have any issue in principle with the overall standards of performance being replaced by similar, streamlined reporting standards under the IIP reporting framework, and we shall provide further comment in response to the fifth version of the IIP Regulatory Instruction and Guidance (RIGs) for comment.

2.4 INTERRUPTIONS INCENTIVE SCHEME

(Paragraphs 4.24 to 4.55)

2.4.1 Form of the incentive scheme

51. We support the move to a symmetrical scheme with annual rewards; the retention of the same incentivised measures (i.e. CI and CML); the increase in revenue exposed to performance against these two measures; and the exclusion of exceptional events.

52. We have previously argued against the proposal to reduce the weighting applied to planned interruptions on the basis that this could cause companies to reassess

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 could push up the number and/or duration of interruptions, to the detriment of customer service. This concern has been partially, but not fully, removed as the proposed 50 per cent weighting is, to some extent, offset by the proposed increase in the CI and CML incentive rates.

2.4.2 Setting targets/cost allowances

53. We welcome the move to exclude 'severe' events from both the IIP target setting and IIP reported performance. This should ensure appropriate basing of IIP on the underlying performance of the distribution network.

54. We generally support the use of the disaggregation process to inform the IIP CI and CML targets. However, there are four issues that still need to be addressed with regard to the setting of targets. These are:

- the inclusion of unit-protected circuits in the HV benchmark;
- the forward projection of planned interruptions;
- the over-reliance on CML per CI in setting the CML benchmark; and
- cost/performance trade-offs.

55. We will be providing a separate detailed paper concerning how the above factors affect target setting and suggested ways of dealing with them.

2.4.3 20 kV System Infrastructure Improvements

56. NEDL's FBPQ submission included investment required to improve the performance of NEDL's 20 kV system up to that of an equivalent 11 kV network. This has been disallowed, and the obvious inference from this must be that Ofgem considers that the overall performance of the NEDL network is acceptable in terms of the number of interruptions seen by individual customers. We do not believe that this opinion is consistent with the opinion of the electrical inspectors at the Department of Trade and Industry (DTI) who are responsible for enforcing the requirements of the ESQCR.

57. Aside from the customer service issues of having one area within NEDL's distribution services area that is inherently performing much worse than is typically the experience in other, similar, areas of the country, our main concern is with regard to regulation 3 of the ESQCR (previously regulation 17 of the Electricity Supply Regulations). The DTI's

report on the ‘North Northumberland’ enquiry stated that NEDL would be in breach of regulation 3 if the poor performance of the network were allowed to continue because the network would not be constructed, installed, protected, used and maintained as to prevent interruptions of supply so far as would be reasonably practicable.

58. This statement was made even after the company had committed to work that brought the long-run average performance for customers in the area to 1.2 interruptions per year. It needed the further addition of two firm busbars that improved the estimated reliability to a long-run average of 0.9 interruptions per year before the inspector was satisfied that regulation 3 would be met.

59. The recent work on disaggregation of HV performance has highlighted that NEDL's 20 kV system has by far the longest HV circuits in the country. Although the disaggregation work has also shown that these circuits, km for km, perform much better than average, customers nevertheless see a much worse performance than is normal in the rest of the country. In fact, nationally, long HV overhead circuits (the OH3 groups) perform at an average of about 1.5 interruptions per annum. Given that the DTI inspector considered an average interruption rate of 1.2 as potentially being in breach of the ESQCR, then NEDL considers itself at high risk of further enquiries of the ‘north Northumberland’ type, with the potential both for being held in breach of the ESQCR if we were not actively improving interruption performance and for resulting costs and penalties.

60. Although the company may not necessarily agree with the DTI that an interruption rate of less than 1.2 (north Northumberland) or even 1.5 (OH3 group) is required to meet regulation 3, we cannot but accede in our planning to the clear intimations of the DTI inspectorate in this area: we are therefore acutely conscious that parts of the 20 kV system inherently perform well outside these figures. The proposed 20 kV infrastructure improvement programme is the minimum required to achieve the defensible position that NEDL's 20 kV customers do not see any worse performance than that experienced in similar rural locations in other parts of the country.

2.4.4 Rewarding current best practice

61. As a general principle, if Ofgem is to provide discretionary awards then we believe these should reward excellence in areas valued by customers that are not already rewarded by other means.

62. During DPCR3 CI, CML and telephone response all had defined incentive schemes associated with them. We consider that it is not appropriate to ask customers to fund further rewards over and above these defined values in these particular areas.

63. That said, we agree with the principle of what Ofgem is seeking to achieve here and we believe, to that end, that it would be appropriate for Ofgem to recognise DNOs – such as NEDL and YEDL – that have exhibited excellent all-round performance against a broader package of measures in areas that are not rewarded elsewhere. NEDL and YEDL have been shown to be efficient in terms of both opex and capex but, in the setting of the allowances for DPCR4, Ofgem has given no recognition of the standards that we have set in respect of safety, customer service and environmental performance and the costs that these involve. Other areas of excellence include short interruptions and storm resilience. These are areas of performance where not only do customers value improvements, but there were clear inferences in the DPCR3 settlement that improvements were required but could not be incentivised only because of the difficulties with measurement. NEDL, by virtue of a large investment in arc suppression coils, now has by far the best short interruption performance of all DNOs relative to its circuit length. YEDL, because of large investments in strengthening its overhead network, has the most resilient network of all DNOs.

2.4.5 Setting incentive rates

64. We support the use of the top-down approach for the setting of incentive rates and are comfortable with the proposed incentive rate. However, we consider that the bandwidths should be less than proposed and would support retention of the present 15 per cent for CI and 20 per cent for CML.

65. Both NEDL and YEDL have delivered major improvements in performance during the current price control period, particularly in respect of CI. This makes further improvements much harder to achieve. Although Ofgem proposes numerically-symmetrical reward/penalty bands for IIP going forward, out-performance (and hence being on the reward side) is more difficult to achieve in practice than under-performance (and being on the penalty side). Given this situation, there is a strong case for the band on the reward side to be narrower than that on the penalty side.

2.4.6 Audits and adjusting data for accuracy

66. Currently the IIP process requires DNOs' performance reporting to meet an overall accuracy of 95 per cent. Ofgem proposes to increase this to 97 per cent.

67. Whereas we agree with the current arrangements for adjustments where overall inaccuracy is found to be outside the proposed three (currently five) 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 plus or minus three per cent are more likely to be due to the accuracy constraints of the audit itself than to actual under- or over-reporting. Nevertheless, if there were clear evidence of systematic under-reporting over several years, even if it were less than three per cent, then we would agree that adjustments would be appropriate.

2.4.7 Frontier performance in DPCR3

68. It is our understanding that Ofgem proposes a relaxation of the current IIP scheme for companies deemed to be frontier performers for either the CI or CML measures when compared on a disaggregated basis. This relaxation would manifest itself in terms of a company deemed to be at the frontier on one of the measures being allowed to take part in the out-performance scheme for that measure even if it should fail the other.

69. The present scheme, which requires DNOs to beat both CI and CML targets to gain any reward, is heavily skewed towards penalties. A DNO that is performing, on average, to target will have a 70 per cent chance of incurring a penalty and only a 30 per cent chance of receiving a reward. Work that has been done to date in identifying frontier performers has not considered many of the legitimate factors for differences in performance and in particular not considered the cost/benefit tradeoffs that exist. It is therefore difficult to be certain that those DNOs currently appearing to be on the frontier, will in fact remain so when all relevant factors have been considered. We therefore believe that the only equitable way forward at the present time would be to remove the conditional requirement for all DNOs, as is proposed for the scheme post-DPCR3.

2.4.8 Storm Arrangements

70. We supported the introduction of the 'interim arrangements' and generally welcome the further development of these. In particular we welcome the introduction of an intermediate time band for medium events. With the benefit of hindsight it has become apparent that the jump straight to 48 hours in the 'interim arrangements' was too large a step. We felt very uncomfortable about applying 48 hours to the ice storm that occurred in NEDL's area on new year's eve last and would have preferred for there to be a shorter period for smaller events of this type.

71. The 'very large event' thresholds are too big to be credible (310,000 for NEDL and 500,000 for YEDL). The proposed values are more than any event seen in the last 20 years in NEDL, and the December 1990 storm was the only event that exceeded the threshold in YEDL. We have suggested to Ofgem an alternative calculation method based on the number of customers connected to overhead lines which we feel to be more appropriate.

72. This alternative calculation, which is based on the number of HV customers per km of overhead line (as derived from the OH3 disaggregation groups), is more realistic in respect of an event that will cause major disruption to supplies and very extended restoration times. Using a '50 per cent at risk' principle would result in the thresholds being 91,000 customers for NEDL and 114,000 customers for YEDL. If these figures were used, then we would expect the threshold to apply to the number of customers affected by HV faults only. In the last 20 years, only the December 1990 storm, which was truly exceptional in terms of the damage caused to the HV distribution system, would have exceeded these thresholds in NEDL and YEDL. In this storm NEDL lost 170,000 customers and YEDL 210,000 customers due to HV system faults.

73. Ofgem's calculations of 'allowed storm costs' do not take into account the probability of a repeat of the1990 storms. As a minimum this should be taken into account and would increase the YEDL allowance from £0.5m to £0.8m (since including 1990 would result in a 0.15 probability per annum of a major event in YEDL). We note also that Ofgem has excluded from its calculation of the allowances the effects of severe flooding. This is a major 'storm' issue in both NEDL's and YEDL's distribution services areas and is a legitimate storm risk that DNOs have to carry. In the last four years, exceptional events (including floods and fires) have cost NEDL an average of £1.4m per annum and YEDL £1.3m per annum. Thus, although the proposed NEDL exceptional event allowance of £1.9m per annum looks reasonable, the £0.5m

proposed for YEDL is not. Using Ofgem's own calculations, but substituting the actual value of £1.3m for major events, would give YEDL an allowance of £1.7m per annum.

2.5 INCENTIVES FOR THE SPEED AND QUALITY OF TELEPHONE RESPONSE

74. We agree that, as the performance of all companies in respect of the quality of telephone response converges, it is appropriate to move from a relative scheme to an absolute scheme. It is also appropriate to consider the introduction of a separate scheme to reward (penalise) excellent (poor) performance during exceptional events.

75. With regard to the 'normal' events scheme, we agree that the scheme should be absolute rather than relative. However, we believe that it would be more appropriate for the scheme to be symmetrical than for the current proposal to be taken forward, with five times more penalty than reward. We would also emphasise that, for companies which have invested significantly in delivering extremely high customer service, the creation of a 'deadband' between 4.1 and 4.5 would significantly affect their ability to recover historical investment: we would therefore submit that a sliding scale similar to that proposed for the penalty regime would be more appropriate.

76. With regard to the 'exceptional' events scheme, we are concerned that there is not the data available within the industry at present to make it possible even to agree in principle to put revenue at risk. We believe that, in addition to the need to gather accurate data, there is a need to establish the cost of meeting customers' expectations and agree the methodology for funding the requirement. As the impact of severe weather varies widely, we believe that a sliding-scale performance measure akin to that already proposed for severe weather restoration may be appropriate.

2.6 UNDERGROUNDING IN AREAS OF OUTSTANDING NATURAL BEAUTY

77. We agree that it would be inappropriate for Ofgem to include cost allowances to underground overhead lines for the sole reason of visual amenity.

2.7 ENVIRONMENTAL REPORTING

78. We have no issue with Ofgem monitoring specific areas relating to environmental performance and agree that these should not be subject to specific financial incentives. Nevertheless, we believe that Ofgem may wish to bear clearly in mind performance in this area when considering any discretionary rewards for DNOs.

2.8 DISCRETIONARY REWARD

79. It is important for Ofgem to recognise and reward/fund the specific areas of excellence exhibited by companies that are also all-round good performers in a number of already-recognised key areas. We agree with Ofgem that it would be appropriate to apply this reward to performance in the areas of customer service and corporate responsibility, but Ofgem should also consider additional areas such as safety performance and environmental responsibility.

3. DISTRIBUTED GENERATION (Chapter 5)

3.1 INNOVATION FUNDING AND REGISTERED POWER ZONES

(paragraphs 5.5 to 5.18 and supplementary documents – *Further details on the incentive schemes for DG, IFI & RPZs* and *DG, IFI and RPZs – Regulatory Instructions and Guidance Version 1*)

3.1.1 Innovation funding initiative

80. We continue to support the innovation funding initiative (IFI) and agree with the proposals. We shall work with Ofgem via the consultation on the RIGs to establish an appropriate reporting framework. We agree also that it is appropriate to commence this initiative as soon as practicable and shall be writing separately to Ofgem with our proposals.

3.1.2 Registered power zones

81. We continue to support the principles of the regional power zones (RPZ) mechanism, and welcome the increase in the revenue driver to three times that of the 'production' hybrid distributed generation (DG) funding mechanism. However, we still feel that the proposed limitation of the number of RPZs to two per annum per licensee is too restrictive.

3.1 DISTRIBUTED GENERATION INCENTIVE

(Supplementary document – *Further details on the incentive schemes for DG, IFI & RPZs*)

82. We continue to support the use of a hybrid mechanism to fund the 'shared' 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 weighted average cost of capital (WACC);
- absence of specific allowance for strategic investment;
- £1/kW/yr. allowance for operation and maintenance (O&M);
- differential treatment for high-cost projects;

- two per cent deadband on over-recovery before penal interest applies; and
- inclusion of microgeneration in the scheme.

83. However, the proposed scheme is still insufficient to create an incentive that will change companies' behaviour, as the returns available from the currently-proposed incentive rate provide too low a premium to differentiate DG from other investment opportunities.

84. 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 in their behaviour.

85. We would be comfortable with Ofgem's preferred annuity approach.

86. We continue to see no reason why generators should be treated as a special case for network access and do not support the proposals to introduce penalties for unavailability. 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 much-heralded 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.

4. COST ASSESSMENT (Chapter 6)

87. NEDL and YEDL have achieved significant cost reductions during the current price control period and have submitted realistic capital and operating forecast projections for the next period. We believe that there is an efficient trade-off between operating and capital expenditure inherent within the forecasts and that, if changes are made to derive allowances, consideration needs to be given to this balance. However, Ofgem continues to assess operating costs and capital costs separately, as at all previous reviews, and this results in cherry-picking which works against companies, such as NEDL and YEDL, that are able to manage and to demonstrate efficient trade-offs between operating and capital expenditure.

88. Whilst we have issues with the capital assessment, which will require discussions at a detailed working level, we note that Ofgem has broadly accepted the efficiency and reasonableness of our proposals. Both NEDL and YEDL have also been shown to be upper quartile in respect of operating costs and Ernst & Young, in their report, state that '*Ernst & Young's view of CE is that it is a well-run, efficient company, and that the scope for further efficiencies is limited'*. We therefore have serious concerns regarding the allowances which result from Ofgem's analysis and which are published in the *Initial proposals*.

89. It is important to note that, whilst Ofgem does not have confidence in the robustness of its total cost modelling, the results back our claim that both NEDL and YEDL are efficient on a total cost basis.

4.1 OPERATING COSTS

4.1.1 Cost normalisation

(Paragraphs 6.12 to 6.27)

90. Ofgem has made certain normalisation adjustments and then added allowances to address the removal of insurance costs; the removal of the pass-through of storms payments; the forecast increase in tree trimming costs; and improvements in the speed of restoration. Ofgem has also included assumed allowances for licence fees, network rates and ongoing pensions costs and has made deductions to offset the proposed capitalisation of faults, non-operational capex and overheads. We have concerns regarding some of these adjustments:

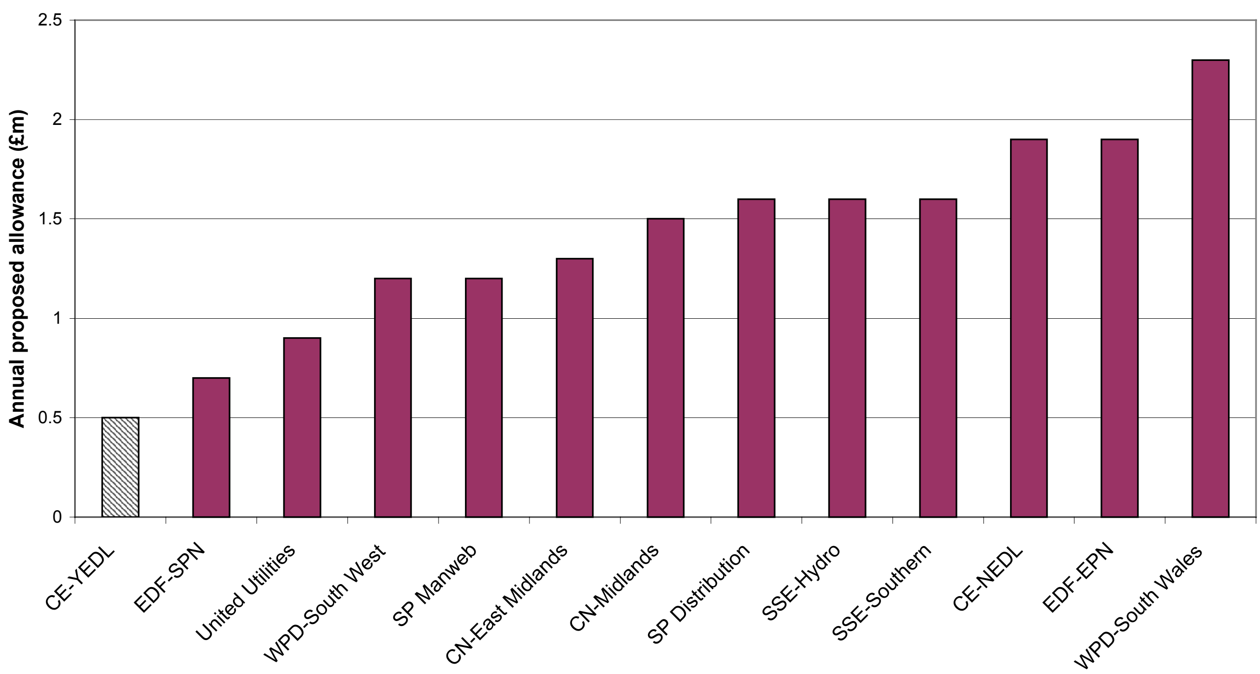
Atypical items, insurance and one-offs

91. We believe that the proposed allowance for atypical costs (including storm and insurance costs) is not adequate and does not adequately reflect the costs incurred in the current price control period. This causes YEDL to be significantly disadvantaged.

92. Excluding severance costs, the average atypical and insurance costs incurred by NEDL and YEDL over the four-year period 2000/01 to 2003/04 were £1.6m for NEDL and £1.5m for YEDL.

93. Ofgem's approach to cost normalisation (Table A1) removed insurance costs prior to analysis of costs under the regression technique. £1.4m of insurance costs were deducted for YEDL, with only £0.5m being subsequently allowed (Table A5) to cover insurance, storm related fault costs, new payments to customers and other atypicals. Thus, the base cost of £1.4m is not being recovered by the current proposal for atypical costs, notwithstanding allowances for other items. In addition, YEDL is also being significantly disadvantaged compared to the allowances currently proposed across the sector. This is demonstrated by reference to the chart below.

Initial proposals: Allowances for Atypicals and Exceptional Events



94. Our current insurance provides for a deductible on property damage of £0.9m. The market-tested premium for the current insurance year to 30 September 2004 is £0.8m for NEDL and £1.6m for YEDL (inclusive of insurance premium tax).

95. The scope of the policy is limited to risks to 'on the ground assets', including weather-related events such as flooding, which have been experienced in recent years. We have not found it possible to obtain overhead line insurance in the commercial market place. Our indications are that if overhead line insurance was to become available it would attract an additional annual premium of circa £3m for NEDL and YEDL combined. Consequently, all expenditure to reinstate overhead lines following a storm event is borne by the licensee.

96. The atypical allowance should be sufficient to cover insurance and weather-related incident costs. Based on NEDL and YEDL data, we would propose an allowance per licensee of at least £1.1m per annum for insurance plus £0.9m for a weather-related incident each year, giving a total allowance of £2.0m per annum. This is the minimum value that should be considered. Actual insurance costs in 2003/04 are £1.4m per annum for YEDL.

97. This proposed atypical allowance only covers insurance and weather costs. It does not include any allowance for severance or deficiency payments to which we may be exposed should we be required to make efficiencies over and above our plan.

98. Notwithstanding the points set out above which reflect our prime concerns in this area we have so far not been able to fully replicate the background methodology used to produce the Ofgem storm arrangement proposals (summarised in the Appendix to the *Initial Proposals*). We have, however, observed that the absence of any YEDL 'allowance for major events' (Table 8: Calculation of exceptional event allowances) is incorrect. We can demonstrate that YEDL has experienced three events inside the last 20 years that fall within this category producing an annual frequency of 0.15. We would expect to see this correction reflected in future proposals if this methodology is to be pursued, in combination with an overall increase in allowances.

Inter-/intra-company margins

99. We have previously contended that reasonable returns should be allowed in the normalised costs. Ofgem now have the data for non-operational depreciation from related parties to make an assessment whether the margins reflect a reasonable return.

Non-operational expenditure

100. Whilst acknowledging that there are difficulties in basing the adjustment on 2002/03 data as this reflects historic spending, we also believe the use of the forecast non-operational capital expenditure will cause methodological difficulties.

101. In considering non-operational capital expenditure allowances, Ofgem has proposed that the use of future spend is a more realistic view than use of historic depreciation. Ofgem has utilised the future non-operational capital expenditure of the DNOs' FBPQs in the regression. This disallows YEDL any consideration of future spend resulting in an adjustment for YEDL of £0m compared to the industry average adjustment of £3.5m.

102. With respect to non-operational capex YEDL's position may be unique as it has assets in both the licence holder and the service provider. If no non-operational allowance is included for YEDL it will be disadvantaged relative to companies that have transferred all assets into the service provider and are receiving all of their non-operational depreciation through the contract charge. The timing and extent of transfers to service providers will also result in inconsistent treatment between companies. i.e. YEDL's non-operational depreciation charges are comprised of charges from the contract with Yorkshire Electricity Distribution Services Ltd (YEDS) for assets that they hold as well as some depreciation on the assets still held within YEDL. Future non-operational capital expenditure is forecast within YEDS while base year expenditure is recorded in YEDL. Therefore it is not possible to compare the past to the future without normalising to treat the costs in a similar manner.

103. YEDL's non-operational capex forecast for the next period is zero but it has assets with lives greater than five years which will not be replaced over the next period for which there needs to be an appropriate non-operational allowance to smooth recovery of this expenditure over time and ensure equitable treatment relative to other companies.

104. For these reasons, any assessment of efficiency for YEDL should be based on non-operational depreciation charges. The non-operational depreciation charges for YEDL and YEDS are:

£m	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
YEDL	4.1	4.5	4.4	4.5	3.8	3.4	3.4	3.1
YEDS	5.9	3.2	4.7	3.7	3.6	3.4	3.4	3.0

105. From the above table, the average non-operational depreciation charge for YEDL over the next price control period is £3.6m. It is not appropriate to consider the charge for YEDS since this is a contract charge to YEDL as the licensee. We believe that the YEDL average non-operational depreciation charge of £3.6m should be applied as the non-operational capex normalisation adjustment prior to the regression analysis.

106. The YEDL five year average (2005-10) compares well to the industry average normalisation adjustment for non-operational capex of £3.5m. Applying this adjustment to YEDL would also provide an equitable solution.

Metering

107. The metering adjustment used in the *Initial proposals* does not accurately reflect the actual cost of the metering activities in 2002/03, which we would suggest are for £5.1m for YEDL and £2.5m for NEDL, as submitted in table 33 of the FBPQ. This included all prime and overhead allocation within CE. The additional 'indirect overhead' allocated cost included in table 19 of the HBPQ is calculated in line with the activity analysis in the regulatory accounts and does not reflect the 'true' cost of the metering activity. The single largest element of this 'indirect overhead' is corporate costs which will not vary with metering activity.

Overhead allocation

108. We propose that Ofgem uses an average overhead allocation adjustment rather than the five per cent banding proposed in the April letter. Using an average approach rather than Ofgem's five per cent band would more accurately reflect the allocation of indirect costs in DNOs. The use of an arbitrary five per cent adjustment on figures decreases rather than increases the degree of confidence in them. It is also not consistent with the treatment of costs provided by the DNOs in other areas. For example, there are significant variances on fault costs but no banding is proposed in this area. We feel that making use of a five per cent banding penalises those companies with less aggressive policies on capitalisation and encourages moves towards further capitalisation of indirect costs rather than promoting greater operational efficiency.

Tree trimming

109. Ofgem has currently benchmarked opex in isolation from other issues, resulting in insufficient recognition of underlying cost drivers, including those for tree trimming. We

have since discussed our tree-trimming model with Ofgem and have demonstrated that the annual allowances should be £4.5m for NEDL and £3.2m for YEDL.

110. Our strategy for vegetation management has been subject to a significant review during the last two years. As a consequence, we have identified a number of opportunities where we can efficiently improve the delivered performance. Most significantly, we have embarked on a programme of ‘cut and manage’ tree clearance, which establishes a greater initial clearance from the line, thereby enabling safer, cheaper, long-run trimming costs (since the number of instances where trees are within the safety zone of live lines is dramatically reduced.

111. We are employing this philosophy with respect to both our HV and, in an appropriate manner, our LV overhead line systems. As a consequence, tree clearances are improved, with the associated benefits to operational reliability. The prime driver is to reduce the long-run costs of maintaining the asset base. Ofgem will see that the costs of this enhanced programme are flowing through our reports levels of expenditure in both 2003/04 and 2004/05. We need to see these funding levels represented in our allowance for the forthcoming DPCR4 period.

Cable fault management

112. The *Initial proposals* do not adequately assess all of the underlying cost drivers and risk cherry-picking low opex from firms with high capex and low capex from firms with high opex. A number of elements of the CE cost projections contain important assumptions that represent a proposal to take advantage of some very efficient capex/opex trade-offs. These include our proposals for fault management.

113. Our plans are intended to address the performance of an ageing (but not poorly performing) cable asset base. The most efficient asset management strategy for this class of asset is to allow assets to fail in service and then target replacement of these cables as their performance is revealed in this controlled manner.

114. We are aiming to achieve stable fault rates on the basis of more pro-active fault management. Without such a step, we anticipate that we would see an increase in the fault rates as some of the less reliable classes of cable asset exhibit a slight increase in their fault rate.

115. The problem of funding is exacerbated by our 2002/03 costs being atypically low in respect of cable faults. Our submission of 2003/04 data will support this assertion. The marginally lower level of faults in 2002/03 is not outside the realms of engineering possibility, although we cannot prove that there was not an element of under-reporting in that year. The fact remains that our submission to Ofgem is consistent with our own reported cost levels and, in line with Ofgem's proposal conclude the operating cost normalisation process, we do not contend that these numbers ought to be adjusted.

116. However, we must stress that what matters is not the 2002/03 levels of expenditure, but the most reliable view of the efficient costs that will be incurred in the forthcoming period. The output of the regression analysis provides an acceptable route to informing Ofgem's view of 'base-opex', but in the case of faults, it is clearly reasonable to expect that the efficient demands of the CE asset are clearly higher than they were in 2002/03.

117. Based on a target to maintain overall fault rates, we projected a constant level of expenditure, on the basis that the same overall efficiencies as shown elsewhere would, in this category, be applied instead to fund the aggressive resolution of intermittent LV underground cable faults.

118. Around a third of total faults costs (about £11m pa (CE)) are related to LV underground cable faults. We estimate that more pro-active fault management to hold fault rates steady would increase unit costs by around 20 per cent, or £2m pa, over the course of the period.

119. Crucial to our case to have this opex allowed is the level of cable investment that we have (or rather have not) forecast. In their report, PB Power note that our forecast for cable expenditure is significantly lower than their model, which itself already takes account of what they describe as a poor cost-benefit return on cable replacement. We are able to forecast this efficient level of capital expenditure as a direct consequence of our assumption that pro-active fault management would be considered as an effective total cost solution to the challenges posed by the cable asset base.

QoS allowance

120. In our response to Chapter 4 of the consultation response we contend that it is more efficient to also allow an element of capex to address improvements in reducing the duration of interruptions. Ofgem have sensibly started to recognise the trade-off between opex and capex considerations for QoS performance. We are not fully

convinced that cost/performance trade-offs have been optimised for all companies and believe that a modest increase in QoS capex is required.

4.1.2 Top-down benchmarking

(Paragraph 6.19)

Basic regression

121. Regardless of the method of assessment that is used, it is vital that NEDL and YEDL should be allowed their efficient operating costs after taking into account the outputs that each DNO delivers and the trade-offs that we are able to manage between our operating and capital expenditure. To this end it is important that the analysis should recognise all performance aspects, not just cost, when assessing overall efficiency. Ofgem has, in its *Initial proposals,* recognised and significantly rewarded both WPD licensees for being good at one aspect of performance. No other company has received such treatment. CE manages two of the best-performing DNOs in terms of operating cost efficiency, capital planning and overall performance in respect of safety, customer service and environmental integrity, and should be similarly recognised for this.

122. If regression is to be used as part of the cost assessment process, we still 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 allow the most efficient companies to enjoy the benefits of efficiency savings for longer.

123. 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 improved the data set, we are not confident that the results of that, or the accuracy and consistency of certain elements of the CSV data, can currently justify a benchmark other than the average.

124. With regard to Ofgem's policy on the treatment of mergers, the March *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.

Composite scale variable

125. With regard to the CSV, we have serious concerns relating to the validity of increasing the weighting on circuit length. These concerns are compounded by our unease

relating to the accuracy of the circuit length measure - it does not have a prescribed definition, Ofgem does not audit it, and its absolute value and accuracy are subject to potentially significant change due to recent technologies that provide new techniques for its measurement. Both NEDL and YEDL would see a step reduction in recorded circuit length by moving from the established ledger (additions/recoveries) method of calculation to one that traces circuit lengths directly from our network records and, as we discussed during our meeting on 7 May, the change in YEDL alone – if factored into the regression – would result in a reduction in income of £11m over five years. This method is relatively new, has not been subject to audit and comparison and is therefore unproven, particularly since it is not consistently in use across the industry. Hence the sources of inaccuracy in these newer processes are less well understood than in more established methods. We are very concerned that an untried process with so many uncertainties and potential inconsistencies should be poised to play such an important role in establishing operating costs.

126. Moreover, we do not believe circuit length to be a significant driver for inclusion in the regression. It may be a reasonable proxy in some companies for the true, more complex, set of cost drivers, but we have seen nothing to suggest that half of the variable operating costs of a DNO are driven by the length of the circuits. Including circuit length with such a large weighting rewards the companies that happen to have disproportionately long circuits and penalises the companies whose circuit lengths are disproportionately short. Therefore, if Ofgem is to place any weighting on this measure, it is clear that it must first be satisfied and able to demonstrate that:

a) this is a genuine cost driver in the businesses, influencing expenditure to the same degree as is assumed in the regression (i.e. if it attracts a weighting of 50 per cent in the regression, Ofgem must be sure that it drives 50 per cent of the costs); and

b) the definition is consistent across all companies and the measurement data is collected at an appropriate level of accuracy.

127. We therefore strongly believe that Ofgem has no sound basis for changing the weighting from that used at the last price control review (i.e. 50 per cent customer numbers, 25 per cent units distributed and 25 per cent circuit length), since:

- the underlying data is collected on an unaudited basis, so that weighting it so highly diminishes significantly the value of the normalisation process that has been performed;

- companies which are outliers relative to other companies are unfairly treated under the approach proposed;

- the correlation between the operating costs of the DNOs and circuit length is significantly lower than 50 per cent;

- companies that have shown increases in circuit length since 1998 are closely correlated to those with high circuit lengths per customer – potentially implying systematic over-reporting; and

- the implied optimal weighting of circuit length within the CSV factors for our current cost data is about 30 per cent.

128. We are also concerned about the circuit length figure that has been used for YEDL in the analysis. Our letters to Martin Crouch in May/June suggested an alternative figure.

4.1.3 Total opex allowance

(Paragraphs 6.57 to 6.62)

Catch-up period and projected ongoing efficiencies

129. It is unacceptable that Ofgem should deny the CE companies the costs forecast in the forecast business plan questionnaires (FBPQs) submitted to Ofgem. Productivity assumptions derived from total factor productivity analysis cannot reasonably be used in substitution for the costs that have been included in the FBPQs

130. We agree that all companies shown to be behind the benchmark should be required to catch up by the start of the next price control period – whether the benchmark is the average or the upper quartile. However, if Ofgem is to choose the upper quartile as the benchmark, it is inappropriate for Ofgem to assume that these companies can continue to reduce costs at a rate of two per cent per annum.

131. We note that Ofwat, in its recent determinations[3], only expects the leading water service companies to achieve continued annual efficiencies of 0.3 per cent, which is half of what Ofwat's considers to be the total scope of efficiencies available to these companies. Ofwat goes on to say that it is necessary to have an appropriate balance between incentives efficiency assumptions included in the price limits and that

[3] Future water and sewerage charges 2005-10, draft determinations, 5 August 2004

including the whole of the scope for improvements in the price limits would not provide companies with any incentive to outperform.

132. CE factored into its plans a one per cent per annum reduction in R&M costs (not total operating costs) for the forthcoming price control period. Even though we have not identified all the initiatives to achieve this reduction, we believe that it is a reasonable forecast and that Ofgem should allow us our efficient costs.

133. Both NEDL and YEDL have also been shown to be upper quartile in respect of operating costs and Ernst & Young, in their report, state that '*Ernst & Young's view of CE is that it is a well-run, efficient company, and that the scope for further efficiencies is limited'*. We therefore have serious concerns regarding the allowances which result from Ofgem's analysis and which are published in the *Initial proposals*.

134. 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 improve significantly upon the efficiency gains in the economy as a whole.

135. 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 net present value (NPV). Companies should not be expected to pass on the benefits from these savings to customers before the savings have been made. This is clearly not credible.

4.2 CAPITAL EXPENDITURE

4.2.1 Historical capex and RAV roll-forward

136. We agree that the RAV needs to be rolled forward from 1 April 1998 to 31 March 2005 based on the policies used to set capex allowances at the last price control review. It is important that CE should not be disadvantaged relative to companies whose disclosure was not as complete as was our own. 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. We are encouraged thus far by the approach that Ofgem is taking.

137. 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 post-DPCR3 price control period, this needs to be reflected in the derivation of the opening RAV for the DPCR4 period.

138. A satisfactory outcome to this process is essential to the acceptability of the final proposals.

139. For a number of adjustments we understand and acknowledge the Ofgem rationale for the proposed adjustments. We concur with Ofgem's suggested areas with the exception of asset disposals and comment specifically on faults and overheads.

Asset Disposals

140. Fully depreciated assets that are not necessary for the conduct of the distribution business belong to the shareholders. Disposals of such assets are irrelevant to price control and no adjustment should be made to RAV.

141. We can see that where an asset, forming part of the RAV, is disposed of prior to having been fully depreciated it would be equitable to deduct from the RAV the share of the RAV represented by that asset at the time of its disposal. This would equal its remaining earning power had it not been disposed of.

142. However, assets (e.g. land that was inherited at privatisation) that form part of the pre-vesting RAV and have been fully depreciated no longer earn a return or generate depreciation allowances even though they may still be used by the business.

143. It seems wrong to deduct from a RAV that does not include such assets (because they have been fully depreciated) any value that arises from disposal.

144. There should be no adjustment to RAV for the disposal of assets that have been fully depreciated and are no longer required by the distribution business to meet its statutory duties.

Fault capitalisation

145. The treatment of fault costs was not transparent at the last price control and retrospective application of policy is subject to problems of estimation. We require an equitable solution that is consistent across the sector and is not highly sensitive to spurious estimates.

146. The policy for fault treatment that Ofgem now say was applied at DPCR3 was eventually published in May 2004. Applying that policy retrospectively is problematic because systems have not been in place to capture the data and companies will need to provide estimates. An alternative approach is to assess the allowances made at DPCR3 and to make a one-off adjustment to RAV that reflects the additional operating cost allowance that would have made to YEDL and NEDL if the other DNO operating cost numbers had contained all fault expenditure.

147. The debate on fault capitalisation has been on-going for over two years as a result of work on Regulatory Accounts. Many companies claimed they were allowed fault costs in capital expenditure at DPCR3 and, therefore, should be able to include the costs incurred under these headings since 1998 in the opening RAV for 2005/06. It has been and remains our contention that YEDL and NEDL had this expenditure treated as opex.

148. Eastern provided evidence that their level of faults capitalisation in 1999 was 50 per cent, Southern maintain it was 100 per cent opex and the average over the all DNOs was 79 per cent to opex. We, therefore, sent a letter to Ofgem, dated 18 November 2003, requesting that these costs be restored to our RAV as at 1 April 2005 in the form of a one-off adjustment of £23.4m for NEDL and £35.8m for YEDL (at 1997/98 prices).

149. At the Cost Assessment Working Group on 4 December 2003, which was attended by David Gray and Martin Crouch, Carl Hetherington said that it seemed clear that the intention on the part of Ofgem, PKF and PB Power was to exclude fault costs from capex. The capex allowance was calculated through bottom up modelling using PB Power's unit costs and therefore did not include fault costs. Therefore, he contended that this was not an issue for the DPCR4 RAV roll forward.

150. This was contested by a number of DNOs who indicated that they could provide evidence to contradict this assertion. David Gray indicated that Ofgem would consider the matter further in the light of any evidence submitted.

151. In May 2004, Ofgem issued, with the RAV forward work programme, a document headed 'Fault Capitalisation Policy Applied at DPCR3' which indicated that at DPCR3 some fault expenditure should have been capitalised, including cables and lines over 50m and EHV faults. We were requested to complete a table retrospectively on a basis that was consistent with this recently discovered DPCR 3 policy.

152. It is evident that the policy on fault capitalisation at DPCR3 was not consistently applied at that review by Ofgem or afterwards by the companies. Attempting to apply this policy retrospectively to the period 1998/99 to 2004/05 is problematic because systems have not been in place to capture the data and companies will need to provide estimates. An alternative approach is to re-assess the allowances at DPCR3 and allow a one-off adjustment to RAV. This adjustment would reflect the additional operating cost allowance that would have been made to YEDL and NEDL if the Eastern operating cost number had contained all fault expenditure.

Overheads

153. The application of overhead capitalisation and entry in to RAV needs to be consistent with PB Power's assessment of efficient benchmarks at DPCR3. We understand this is not available and expect a fair and pragmatic solution, which may need to consider the output of the normalisation process applied to 2002/03 data as the best available average of indirect costs in capital.

154. The capital allowances at the last price review were based on PB Power's benchmarks. PB Power have indicated they do not have a further break-down between direct and indirect components. All companies have undergone restructuring since DPCR3 and the assumptions about the attribution of costs between the distribution and other businesses changed at the last review. This makes it difficult to track historic capitalisation policies.

155. Ofgem concluded in the normalisation work that companies had different capitalisation policies and arrived at a methodology that deducted £17m from our normalised operating costs in 2002/03. This represented CE's under-capitalisation of overheads compared to the banded average.

156. The issue arises that an adjustment to RAV is required to ensure that the RAV is rolled forward on a consistent and equitable basis.

157. The Ofgem RAV roll forward information request indicates two potential options - either the RAV roll forward should be carried out on a company specific basis (i.e. adjusting for any changes in the accounting policies of a company during the price control period) or it should be rolled forward in a manner consistent with the accounting policies adopted by the efficient frontier company at DPCR3 (i.e. indirect costs would be allocated between opex and the RAV in the same proportion as the frontier company's ratio of direct to indirect costs at DPCR3).

158. We contend that the relative position is irrelevant. The capital allowances set at DPCR3 were based on PB Power’s benchmark and it is the allowed level of overhead in the benchmark that determines a consistent method to roll forward the RAV.

159. Our discussions with PB Power indicate that an analysis of their benchmark is not available.

160. Even if this were available, companies would have to provide their calculation of the level of overhead capitalisation on exactly the same basis as PB Power over a period of significant change both within companies and the industry. The last review and the business separation exercise that followed it changed the boundary between the distribution business and other businesses. This makes it hard to re-create asset additions and subtractions that would be consistent with the PB Power benchmarks.

161. The pragmatic solution to the adjustment of the RAV to reflect a proper and equitable share of overheads is to derive from the results of the 2002/03 normalisation process a factor that reflects the indirect capitalisation allocation compared to the average and to apply this factor from 1997/98 to 2004/05 to make a one-off adjustment to RAV.

162. It has been a consistent theme of CE’s submissions during this review that the price control review process should not reward the wrong behaviours while penalising the right ones. The roll forward of the RAV and the adjustments necessary in respect of faults and overheads is an area that Ofgem should ensure that it is not reinforcing the wrong incentives.

4.2.2 Review of future capex

(Paragraphs 6.69 to 6.87)

163. We note that Ofgem’s view of the allowances has been driven in the main by the report from its advisers, PB Power. PB Power's work has merit insofar as it allows Ofgem to perform a rough-cut on the forecasts of the DNOs. This rough-cut has the ability to eliminate proposals from extreme outliers and to bring into focus those more subtle features of other (more reasonable) forecasts, which then require further discussion. This in particular has led to a reduction in ‘core’ capex for YEDL and a reduction in overheads for YEDL and NEDL against our initial forecasts. We do not believe this disallowance is merited and have provided a more detailed response in a separate paper that addresses the issues from the PB Power report.

Load-related expenditure

164. We accept that 'reinforcement spend can be expected to be cyclical to a degree since capacity is released in discrete blocks', but we submit that we are approaching a high, rather than low, point in the cycle. Specifically, there have been no new bulk supply points (BSPs), such as that which we propose for Hull, since Vesting and we now need to carry out significant works on the YEDL 132kV system.

Non-load related expenditure

165. We are pleased to see that PB Power recognise, for overhead lines and plant, the efficiencies captured within our forecasts. However, we are disappointed to see that these efficiencies have not been appropriately treated. Indeed, there is cherry-picking of whichever of our forecast and PB Power's model gives the lower answer. In aggregate, our adjusted forecast (before correcting for overheads as discussed later) is £32.7m below the PB Power model.

166. We accept that PB Power have applied some engineering judgement, rather than mechanistically relying upon their models, but we submit that their approach remains inconsistent and unfounded.

Overheads

167. We welcome Ofgem's attempts to ensure recovery of the full value of overheads transferred out of revenue within the capital analysis. However, these overheads should not be attributed to all categories of capital expenditure, specifically metering and faults.

168. In CE's structure, all metering is delivered under contract by the unrelated npower metering businesses. Therefore, minimal CE overheads accrue to this activity and no more should be attributed.

169. There are a number of oversights in the *Initial proposals*, in that:

- overheads are attributed to faults;
- faults are combined with operating costs;
- overheads are transferred out of this sub-total; and
- the remaining figure is subject to regression.

170. The net effect of this is that, as the faults figure used for regression excludes overheads transferred from revenue to capital, PB Power have inadvertently attributed overheads to a category of expenditure from which they cannot be recovered. This should be corrected for, by moving overhead recovery into non-load related (NLR) expenditure and increasing overall capex assumptions.

171. We accept that increases to expenditure projections should still be subject to an efficiency assessment. However, as so much of our forecast falls below the PB Power model benchmark, we are confident that this investment will still be allowed.

4.2.3 Setting capex allowances and investment incentives (sliding scale approach)

172. We fully support Ofgem's sliding scale approach and the retention of this mechanism will be a key factor in our decision regarding the acceptability of the final proposals. However, there are a few issues that need to be addressed to prevent the overall dilution of incentives for efficiency.

173. Capital efficiency based on reasonable forecasts should be strongly rewarded and the sliding scale mechanism proposed by Ofgem provides greater returns to companies that have submitted reasonable forecasts and then either meet or beat those forecasts. However, the proposals do not go far enough in reducing discrepancies between companies. The PB Power method appears to systematically derive low benchmarks where companies have forecast most efficiently. The PB Power benchmarks should be increased or allowed capex set with increased headroom above the PB Power value – we suggest 110 per cent for top performers. This is supported by allowed income per customer, which is diverging across licensees. The additional 0.2 per cent return to reward companies that choose the lowest allowance is also too small and is much lower than the WPD reward for quality of supply – it needs to be increased to 0.3 per cent to equalise the values.

174. The proposed maximum overall marginal incentive rate is only equivalent to that available under the current rolling capex incentive mechanism, given that Ofgem proposes to reduce the categories of costs that are subject to the rolling opex incentive mechanism. We would advocate the overall current incentive on opex and capex is maintained for top performers. This could be achieved by adjusting the sliding scale mechanism to increase the rewards for the good forecasters by increasing the benefits retention from 40 per cent to 65 per cent, increasing the cost of capital by 0.3 per cent and by setting the capital allowances equal to 110 per cent of the PB Power

benchmark. If the capital sliding scale is not strengthened then a higher cost of capital is required.

175. In addition, as we have stated at other relevant points in this document, the increased risk that companies face due to the transfer of costs from the ‘expensed’ to the ‘depreciated’ category should be recognised through an increase in the cost of capital.

5. FINANCIAL ISSUES (Chapter 7)

5.1 THE COST OF CAPITAL

(Paragraphs 7.1 to 7.14)

176. We note that Ofgem have used 5.4 per cent pre tax cost of debt, post tax cost of equity (the vanilla WACC) to model revenues but it is explained this is for modelling purposes and does not represent a decision on the appropriate cost of capital. We also note that this is unlikely to be updated in the September paper but we would request Ofgem do provide a preliminary view so that we can properly assess the financeability and cash flows of our business.

177. In particular we are concerned that the *Initial proposals* understate the tax due. We will work with Ofgem to ensure that subsequent proposals make more appropriate allowances for the taxes to be paid by NEDL and YEDL.

178. In previous consultation responses we have provided arguments why we see no rationale for proposing a cost of capital range lower than that proposed by Ofwat for the water industry. Indeed we have suggested that only a cost of capital at the top end of the Ofgem range would meet city expectations and be similar to the calculations being applied to the water industry.

179. The Ofwat Draft Determinations published on 5 August 2004[4] indicate a cost of capital of 5.1 per cent on a real, post-tax basis. This is at the high end of their quoted range of 4.2 per cent to 5.3 percent.

180. Adjusting for Ofgem's higher gearing assumptions, the Ofwat numbers translate into a Vanilla WACC of 5.66 per cent (within a range of 4.58 per cent to 5.84 per cent). This reinforces our previous arguments that the Ofgem estimate is too low.

181. The water industry is not the only benchmark, we have previously indicated that there are a number of other comparators including the output of the NERA work, European utility returns and city expectations of the total regulatory return in a regime which has reduced out performance incentives. These issues are further explored in the ENA letter, 'Weighted Average Cost of Capital', dated 23 July 2004.

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[4] Future water and sewerage charges 2005-2010, Draft Determinations, Summary, Ofwat, 5 August 2004

182. The allowance for debt finance needs to allow for the prospect of increasing rates over the next review period as well as being adjusted to reflect the efficient debt financing undertaken in previous periods.

183. A higher cost of capital is supported by the need to reflect the higher risk (and smaller returns) brought about by proposals to:

- diminish opportunities for out-performance;
- equalise and weaken the rewards for out-performance incentives; and
- move a large component of costs from the ‘expensed’ to the ‘depreciated’ category.

184. The *Initial proposals* understate the tax due. We will work with Ofgem to ensure that the September document makes more appropriate allowances for the taxes to be paid by NEDL and YEDL.

5.3 REGULATORY ASSET VALUE AND DEPRECIATION

(Paragraphs 7.15 to 7.17)

185. We agree that Ofgem should apply the same principles as were applied to some companies at DPCR3 to address the issue of the full depreciation of pre-Vesting assets.

5.4 PENSIONS

(Paragraphs 7.15 to 7.17)

5.3.1 General

186. We recognise that in the *Initial proposals* Ofgem used a preliminary estimate of the size of the deficit, which was based on the actuarial assumptions used for the 2001 valuation. For the CE group this estimated deficit as at 31 March 2004 was £117m. Full deficit funding would require around £13m pa over 13 years allowing for the time value of money.

187. Based on Ofgem’s assumptions over the allocation of surplus and the disallowance of ERDCs the allowances in the *Initial proposals* for pensions deficit costs were only £1.3m pa for NEDL and £1.4m pa for YEDL. This represented a significant shortfall against the actual funding.

188. However, we do acknowledge that Ofgem sees merit in the arguments to allow some ERDC costs which were not included in the above figures.

189. The following paragraphs also note other areas where the assumptions in the *Initial proposals* need to be amended.

5.3.2 Allocation between price-controlled and non-price controlled activities

190. The CE group operates one ESPS pension scheme which includes members employed by NEDL and YEDL. The allocation of the scheme deficit between these two companies has to reflect their different demographics as well as the circumstances of the transfer of staff between Innogy and CE in 2001. Overall this results in the YEDL deficit representing a significant proportion of the overall deficit.

191. We welcome Ofgem's recognition that the deficit relating to YEDL relates fully to the distribution activity. Ofgem's assessment of 80 per cent for the NEDL deficit is too low as it fails to reflect both the historical staffing of Northern Electric plc and the current position where the involvement of ESPS staff on non-distribution activities is minimal.

192. We have provided Ofgem with an analysis supporting the argument that at least 92.5 per cent of the NEDL deficit relates to the distribution activity.

5.3.3 Under- or over-provision

193. We recognise the issues related to the level of allowance made in DPCR3 and agree with Ofgem's thinking not to make adjustments for any under or over-funding that might have occurred.

5.3.4 ERDCs

194. ERDCs should not be disallowed in calculating the deficit, on the basis that customers enjoy the benefit of efficiencies realised by the release of employees and so should share proportionately in the cost of achieving these benefits.

195. We appreciate that Ofgem is now able to see the merit in allowing some of the ERDC costs incurred by the distribution activity. Assuming that staff severances were not all achieved in the first year of the price control period, then we calculate that customers have received more than 80 per cent of the present value benefit and should therefore pay more than 80 per cent of the costs of the ERDCs.

5.3.5 Calculation of pension allowances

Deficit funding

196. The allocation method applied to determine the element of the overall deficit relating to the distribution business needs to correctly reflect the NEDL position of at least 92.5 per cent share.

197. We agree that a reasonable deficit repair period should be based on average service lives although this assumption may need to be changed in line with the actual settlement terms agreed with the scheme actuary. The profile and value of the annual payments has to reflect the time value of money in order to satisfy the NPV of the overall deficit.

Ongoing funding

198. The assumed costs should reflect the final actuarial assumptions.

Latest estimate

199. The actuarial calculations for the 31 March 2004 valuation have continued and the latest estimate of the deficit is around £190m, the increase is mainly as a result of the latest estimates of life expectancy. The latest funding rate is estimated at 20.4 per cent. It is anticipated that these latest forecasts will be incorporated in the allowances included in Ofgem's September proposals.

5.4 FINANCIAL INDICATORS

(Paragraphs 7.32 to 7.45)

200. Our shareholders' view, that the *Initial proposals* are unduly harsh on CE, is echoed by commentators in the financial sector.

201. S&P found the proposals to be generally satisfactory but singled out CE as being outside their own assumptions.

202. Barclay's Capital Research have advised that YEDL and NEDL should be avoided as 'broadly illiquid' and highlighted the possibility of a 'downgrade across the group'.

203. There is no reason why this price control review should lead us into trouble with rating agencies and debt holders and we could not be expected to accept such an outcome.

204. Providers of debt funding require the payment of their returns through periodic interest payments as well as the repayment of the principal at the end of the loan term. Equally

equity providers should also expect to receive their appropriate equity return through annual dividends. To the extent that the overall worth of the business is increasing, measured by RAV, then both debt and equity providers should be prepared to provide additional funding in proportion to accepted gearing levels.

205. In a situation where cash is restricted then it is likely that this would require the equity provider to bear the strain. This would either be through restricted returns or the need to contribute additional investment. Neither of these represents an acceptable solution. In cases where cash is restricted then the overall level of cash being generated needs to increase. As we have previously argued this has to come from a further increase in the overall return and not from changes to depreciation assumptions.

206. Our analysis of the *Initial proposals* indicates, based solely on the Ofgem forecasts, that equity cash flows will be restricted over the DPCR4 period. This conflicts with the gearing and cost of capital assumptions made by Ofgem and indicates that the overall level of return is inadequate.

207. Ofgem released the latest draft of their model on 30 July. We are currently reviewing the assumptions and logic of the model. We will respond separately with the specific issues raised as a result of that review.

6. STRUCTURE AND SCOPE OF PRICE CONTROL LICENCE MODIFICATIONS

(Supplementary document)

Broad Principles

208. We fully endorse and support the joint response on this document submitted by the ENA on behalf of all DNOs. We therefore welcome Ofgem's proposals for rationalisation and simplification, subject to the key principles set out in the joint DNO response. In particular we would stress the need for a review of the change control processes and procedures associated with the existing IIP RIGs in the context of the proposal to devolve significant elements of material currently held within the distribution licence into further subsidiary RIGs.

209. Whilst we would have no strong objections in principle to Ofgem's proposal to remove the supply restoration guaranteed standard from the Electricity (Standards of Performance) Regulations and to insert it into a standard condition of the licence which would also embody the proposed arrangements for storm-related supply interruptions, we are concerned, in common with the rest of the DNO community, that this may not be achievable from both a practical and a legal point of view. We fully support the work of the Legal Joint Working Group which, amongst other things, will attempt to resolve this issue.