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EDF ENERGY

25 October 2004

Dear Martin

DPCR4: EDF ENERGY'S RESPONSE TO THE SEPTEMBER UPDATE

Thank you for inviting our comments on the above consultation paper. Our detailed response is attached. I am pleased to confirm that this is not confidential and can be posted on Ofgem's website. You should note that the text contains a number of illustrations which would benefit from being printed out in colour.

It is good to see that progress has been achieved in a number of key areas of the review, including quality of supply, the sliding scale mechanism, and the treatment of pensions and tax. However, there is clearly still much work to be done in other areas and time is getting very short.

We remain particularly concerned about the benchmarking of operating costs, the way that we have been treated regarding changes to Ofgem's composite scale variable (CSV), and the inadequate recognition of regional costs.

The reduced weighting within the CSV given to customer numbers has the effect of disallowing around £8m of opex per year from LPN and SPN. This penalty is over and above that which we suffer anyway as a result of Ofgem's insufficient recognition of the regional wage costs faced by all three of our DNOs. However, despite its August workshop on the subject for distributors and the (unpublished) advice that Ofgem says it has received from its technical consultants, Ofgem has provided no evidence to support its position.

For our part, we have provided detailed reports on urban factor costs, most recently by engineering consultants Black and Veach. In addition we have drawn Ofgem's attention to benchmarking work by PA Consulting that identified the need to treat urban areas differently from rural ones. We have also pointed out that special allowance for companies operating in Greater London and South East England has been given by other regulators (Ofwat) and is common in other sectors (such as local government). We believe that Ofgem must give a proper response to the compelling evidence we have submitted.

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The ongoing financial position of SPN is also an issue of critical importance to us. Clearly, the licence and statutory regime under which SPN (like every other DNO) operates means that the company is financially ring-fenced and must be considered on a stand-alone basis. This means that the solution must come solely from the resources available to SPN and not from any other part of EDF Energy, including LPN and EPN.

Asking customers to pay for accelerated regulatory depreciation charges was the approach taken by Ofgem at the last review. The fact that the same issue in respect of financeability has arisen again reveals that this is not a sustainable solution to the problem. Given that Ofgem has already established that customers' interests are protected by having licensees that can finance their activities, we propose that Ofgem adopts the same approach to financeability as that used by Ofwat, i.e. by providing for the use of company-specific adjustments. We understand the impact that this approach would have on customers, but would emphasise that SPN already has the lowest use of system prices in Great Britain.

With regard to the treatment of merger efficiencies and the treatment of the LE Group's acquisition of SPN, it has always been and remains our understanding that we would be permitted to keep the restructuring benefits, net of integration costs, for a period of at least five years. We expected this to be facilitated by the continuation of the regulatory practice of maintaining incentives by allowing companies a period of time in which to catch up with the target efficiency level. Ofgem's new policy of requiring immediate catch-up was not part of our understanding as it could not have been foreseen at the time of the merger either from past precedent or from discussions with Ofgem at the time.

Regarding the cost of capital, we remain concerned that Ofgem has decided to defer further consideration of this until the final proposals paper. Clearly, this will give no opportunity for companies to comment either on Ofgem's decision or Ofgem's interpretation of the detailed evidence already provided. Our position was most recently set out in a letter sent by SSE on behalf of all distributors, in which the case for parity with Ofwat's draft determinations was made.

Ofgem's focus on price control "sticks" and reduced incentives has left little scope for DNOs to outperform cost and quality targets, with the result that the ability as in past price control periods to earn a premium on the cost of capital will no longer be available. In addition, Ofgem's proposals mean that companies will be exposed to substantial regulatory risk in a number of areas, including the treatment of meter asset charges, the approach to cost benchmarking, and the lack of glidepath. These are all new and unprecedented developments which could not reasonably have been predicted and which, taken in the round, strongly suggest that a cost of capital at least as high as the top end of Ofgem's previously published range would be justified.

Thank you once again for the opportunity to comment on your paper, I hope that you will find our views useful.

Yours sincerely

Paul Cuttill

Chief Operating Officer, Networks Branch

EDF Energy's Response to Ofgem's September 2004 Update Paper on the Distribution Price Control Review

Contents

Metering

We welcome the more in-depth consideration of metering. It is clear that much work has been undertaken between June and September. Unfortunately, it is also clear that there is much to do before a complete and coherent set of proposals is developed and it is essential that DNOs are consulted (as Ofgem has promised) prior to the overall DPCR final proposals.

Meter Asset Provision (MAP)

We welcome the change in Ofgem's stance on company specific price caps. The setting of standard price caps across all DNOs will ensure a level playing field.

In respect of the treatment of overheads associated with MAP, if these have been apportioned on a meter volume basis we would expect that, as volumes reduce, the price capped levels for all meters would increase to reflect this.

Prepayment Meters

Ofgem's proposals expose DNOs to a new risk, namely that their meters will be replaced before the end of their lives by the meter of a competitor. Ofgem has specifically ruled out the imposition of termination payments, even though such payments are found in competitive markets whenever the provider makes a long-term commitment to a customer (e.g. mortgages, mobile phones, leases). It is clearly unreasonable to suggest that DNOs who have provided and will continue to provide a service for a low level of return (consistent with a low risk) should now be denied both a higher rate of return and any form of protection for their investment which was a result of their regulatory obligations.

We appreciate Ofgem's acknowledgment of the risk of early removal due to different types of PPM technology which are outside the control of DNOs and the intent to account for this risk. However the method that has been proposed is flawed. In particular, it penalises (i.e. imposes the stranded costs on) only those suppliers who remain with the DNO for MAP services and therefore distorts competition. It would also encourage further loss of market share by the DNO concerned. Reducing the expected life of the PPM (and allowing the DNOs to increase the price cap to recover the cost of the asset) will only increase the risk that a competitor will supplant the DNO's meter, and further endanger the recovery of its "stranded costs".

In terms of Ofgem's proposals being a proxy for a competitive market, they are flawed for two reasons:

- In a competitive market, providers have no obligation to supply if they think the returns will not provide adequate compensation for the risk. However, DNOs were obliged to provide meters in the past and cannot pull out of the market without incurring losses.

- In a competitive market, providers face the risk of competition, but are able to earn higher rates of return whilst they have an advantage over the competition (e.g. because of a patent), or to demand an upfront contribution to costs, or to impose a charge for early termination of the service. Ofgem has denied the DNOs the right to use any of these measures, whilst simultaneously exposing them to the full force of competition.

Ofgem's proposals therefore put the DNOs in a worse position than a normal competitive business.

We do not understand Ofgem's reluctance to allow DNOs to levy termination charges, particularly as abuse would not be possible given the obvious Competition Act considerations. Moreover, such a charge would prevent inefficient competition from raising costs unnecessarily, when competitors fit new meters at an incremental cost, purely to avoid costs that are sunk and hence cannot be avoided. We would be content for any such mechanism, or any alternative, to be incorporated within the main distribution price control.

The purpose of competition is to promote efficient choices. Ruling out inefficient choices cannot therefore harm competition. Indeed, Ofgem's policy of prohibiting termination charges will create inefficient switching, which is inconsistent with the purpose of introducing competition. DNOs with largely depreciated assets may prefer Ofgem's proposal for their existing assets, but it will expose all new metering assets to a great risk that their costs are not recovered. This outcome may not have been Ofgem's intention and it is likely to be inconsistent with its statutory duties.

It is also difficult to understand how the intent to remove the obligation for new assets post 1 April 2007 will reduce the level of potential stranding from early removal.

Furthermore, Ofgem's cap on the reduction in asset life for existing assets at 30% appears arbitrary and without justification. Ofgem's focus on price stability for customers is also curious since this cannot possibly be an end in itself.

Rate of Return

We believe that the rate of return must be higher than that assumed for the main distribution business. The risks to the newly independent metering activity are clearly greater than those of a monopoly business, particularly if mechanisms for the recovery of stranded costs have the affect of accelerating further stranding. It is difficult to objectively estimate what the cost of capital should be, but an additional 2% would seem appropriate to us.

Meter Operation (MOp)

We recognise that there is still considerable work required before the MOp control is finalised and we welcome the opportunity to demonstrate evidence of our costs. We believe that if an external contract is in place then this represents the market value of MOp services and therefore should be allowed. Should a DNO wish to price up to any subsisting but now out-of-the-money arrangements this should be permitted given that its pricing and market share will stimulate competition. It is difficult to say with any certainty how each of the proposed cost drivers will work due to the different inherent nature of the regional metering businesses and the external contracts that are now in place. We believe that it is a reasonable assumption that the MOp work will be primarily driven by the age, type and number of metering assets on circuit. The total number of transactions would probably give the best representation. However, it may be difficult for DNOs to provide an accurate account of the number of transactions, as there is no clear definition of what a transaction is and some DNOs have not recorded this as part of their current outsourcing arrangements.

Overall, Ofgem must not forget that its statutory duty to allow DNOs to finance their licensed activities extends to metering so long as it remains an obligation.

Basic Services

The Basic Service should only include appointment times which are considered to be "normal", i.e. ten day appointments that take place during normal working hours (per current JPW-based contracts). Any other inclusion under the revenue cap would allow suppliers to change the mix of appointment times and thus the cost base of the DNO without allowing a recovery of those costs.

One Way Door

Though it would be ideal to lift the obligation on a MPAN per MPAN basis depending on the supplier, it is not practicable at this time. We believe it would be easier to implement a solution where the service obligation was lifted after a certain percentage (say 60%) of a particular Supplier's total MAP and/or MOp services for a particular class of meters, had been de-appointed.

Mark-Up

We believe that the margin must be higher than the 1.5% mark-up on costs included in the Revenue Cap proposals. This does not provide sufficient reward to cover the risk and investment undertaken. Ofgem's calculation seems to be based upon a 6.6% return on the perceived level of fixed cost of a MOp business. The rate of return is not commensurate for the risks or the nature of a MOp business. MOp businesses are non asset service businesses which could be considered to operate with low levels of debt, thus having low gearing. Therefore the financing costs of running a MOp business are related more closely to the cost of equity rather than debt. Since Ofgem's cost of equity is 10.36% we would expect the margin on cost to be closer to 2.5%.

Quality of Service and Other Outputs

Interruptions Targets

We are pleased that Ofgem has recognised the issues associated with its original allowances and made appropriate adjustments. There does however remain a need to clarify issues associated with the treatment of the quality of supply revenue allowances where this is used for capital investment, in particular regarding its treatment within the sliding scale mechanism.

We believe that the overall cost allowances for reaching Ofgem's CI and CML targets are broadly consistent with our revised submission.

Whilst we understand the methodology Ofgem has adopted for determining targets, we are both surprised and concerned that Ofgem has not shared its updated target calculation with DNOs. Publication would make this transparent and facilitate the detection of any errors and build confidence in the process. We continue to believe that Ofgem's quality of supply targets, which are based on movement towards an upper quartile benchmark performance, do not create a symmetrical incentive scheme since the probability of outperformance is systematically lower than the probability for underperformance.

We also still believe that Ofgem has used its benchmarking in a way that overstates the level of confidence it should have in it. As a result Ofgem runs the risk of setting overly challenging targets, as we see in the CML target for SPN. To ameliorate this, we propose that the profile of the targets should be adjusted to reflect a greater proportion of the improvement in the later years of the price control. We believe that the targets should be re-profiled as shown below, with 60% of the planned improvement in the last two years of the five year period. This will reflect the actual impact of our remote control and automation implementation programme in SPN's area.

EDF Energy SPN	**3yr av.**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
CI	92	91	89	87	85	83
Revised CI	92	92	92	91	86.9	83
CML	86	81	77	73	68	64
Revised CML	86	84	82	78	70.9	64

We would welcome Ofgem setting out the updated incentive rates despite any changes being small in order to reduce the risk of future misunderstandings.

The proposals for streamlining audits will reduce the burden on Ofgem and its consultants where DNOs have achieved a high degree of accuracy. We believe that Ofgem should consider further streamlining measures where high levels of accuracy are consistently delivered.

Exceptional Events

With regard to the proposals for exceptional events, we refer you to the ENA letter of 7 October and the clear and robust representations of the industry side of the joint legal working group. Ofgem's proposals are based on recent history, and particularly the events of October 2002. However, the storm in October 1987 affected one of our licensed areas much more seriously and was significantly more onerous to recover from than the events of October 2002. The consequences of weather events significantly bigger than those of October 2002 are highly unpredictable. For this reason, we strongly believe that there should be an upper limit on the scale of an exceptional event to which the Statutory Instrument applies and we support the proposals that have been put forward on behalf of the industry.

We do not believe that Ofgem's treatment reflects the appropriate costs of specific flooding events, such as the widespread flooding in Sussex in 2000. Furthermore, if flooding costs are to be included, an allowance should be made for LPN, as this is the one form of severe weather risk which could be, and which the London Assembly reasonably expects to be, experienced in the capital.

Targets for Electrical Losses

We support the updated targets set out in the update paper. However, Ofgem should be aware that our support is predicated on there being in place robust arrangements for revenue protection activities. We note that responsibility for revenue protection is an issue that Ofgem is currently considering, and that any revised arrangements will not be settled until after the DPCR Final Proposals have been published. Clearly, our acceptance of the proposed losses targets would be given on the basis that robust revenue protection arrangements are in place, which enable DNOs to continue to undertake this work should they choose to do so.

Cost Assessment

Operating Costs

Normalisation

We continue to believe that Ofgem's normalisation, while extensive, has not produced consistent and comparable cost data between DNOs, and as a result Ofgem's benchmarking analysis is subject to data errors, which prevent robust and reliable interpretation of the results. Our concerns were set out in more detail in our response to the June Initial proposals paper and in other correspondence and have not materially changed since then.

Of particular concern is the consistency and comparability of accounting data. Ofgem stated in its June Initial Proposals paper that "the existing boundaries between capex and opex are not well defined and that the development of robust definitions is not achievable by final proposals in November", and that DNOs can deliver "efficiency savings by reclassifying costs". We agreed with this and pointed out that material accounting differences remain between DNOs with regard to the normalised costs used in Ofgem's cost benchmarking. In particular, we believe that significant differences remain in the areas of overhead capitalisation and replacement capex. We did not share Ofgem's pessimism regarding its belief that these problems cannot be resolved by November. Faced with benchmarking that Ofgem knows to be less than robust, it has nonetheless continued to propose that companies achieve upper quartile company cost levels, when in fact it has already admitted that some of the differences are due to data definition problems. It continues to be difficult to reconcile Ofgem's approach with its statutory duty to allow companies to finance their functions.

The data available to Ofgem remains inadequate to provide a robust estimate of what costs should be, and hence unreliable for use in defining allowed revenues directly.

Looking forward, clarity is required as to how Ofgem is to apply the principles used in normalisation with regard to regulatory accounting. For example, regarding the treatment of overheads:

  - Will the Band be maintained at the absolute value based on the 2002/3 analysis?
  - Will the Band be maintained at 38% (+/- the 5%) of the total indirect costs each year?
  - Will the Band percentage be reset each year to reflect the average indirect costs capitalised across all DNOs in that year?

- How will Ofgem take into account the fact that, for companies with significantly increasing capex programmes, it is reasonable to expect that the absolute level of indirect costs supporting the capex programme will increase, thereby increasing the percentage of indirect costs capitalised?
- For example, across EDF Energy's DNOs, we anticipate reducing the overall level of indirect costs during the DPCR4 period through efficiency measures. However, at

the same time we will be increasing the support (indirect) costs that directly relate to the increased capital programme and these costs should be capitalised under UK GAAP and IAS.

- We would recommend the appropriate way forward would be to calculate the annual increase in DNOs' capex programmes and apply this to the allowed indirect cost capitalisation from 2002/3 to create a 'capitalisation cap'. If, through the continuation of the DNOs' existing capitalisation policies, the level of indirect costs capitalised remains below the cap, then these costs will be allowed into capex and the RAV.
- As with the 26% capitalisation adjustment for faults and non-operational capex, if Ofgem changes the incentive mechanism so that opex and capex incentives are no longer equal, it will be important that there is clarity over this area to enable proper consideration to be given to the Final Proposals.

Regional Costs

We welcome the acknowledgment of higher employment costs in EDF Energy LPN, SPN and EPN. It is important that the higher costs of employment are recognised as without this any benchmarking exercise will be distorted and inappropriate conclusions drawn on relative efficiency.

Ofgem appears (there is no audit trail provided) to have based its proposed initial annual £6.1m allowance for LPN on the £8m used at DPCR3. However, the £8m allowance represented 11% of the relevant cost base at the time, whereas the £6.1m is just 9%. Ofgem has presented no justification for asserting that the percentage impact of regional cost pressures on LPN has fallen and should make appropriate corrections to its calculation. It is also important to recognise that Ofgem's proposed £6.1m for LPN only represents the additional cost for operational expenditure and expensed faults. This needs to be extended to include capitalised faults.

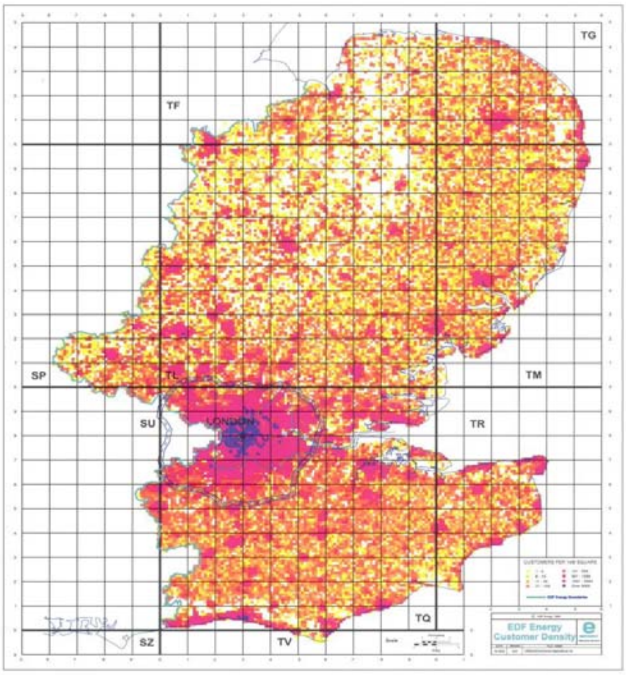
Ofgem has also set opex/faults allowances using the cost levels of the upper quartile companies (EME and Hydro) which are below average regional costs. For instance, their salary and wage rates are 8% and 11% below the national average, according to the National Earnings Survey. Selecting these DNOs for the benchmark makes even bigger the regional cost gap with DNOs operating in SE England. Clearly the regional cost adjustment must recognise all these cost differences, or it will fail to set an achievable target for costs.

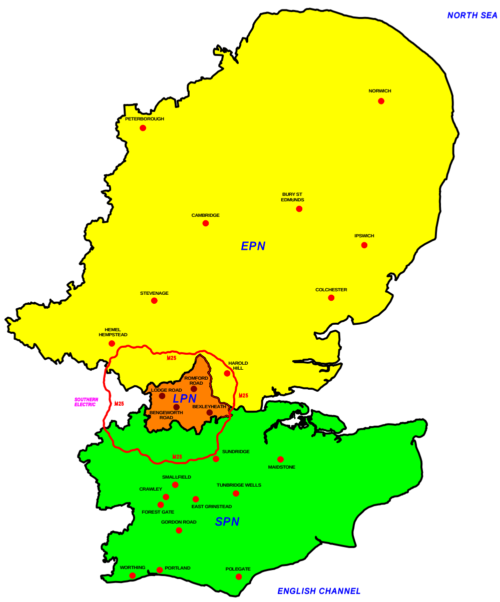
EDF Energy believes that a regional allowance based on exogenous wage costs should be extended to SPN and to a lesser extent EPN. The adjustments should be based on the evidence provided by us, including the Oxera report, and other evidence available to Ofgem. As Ofgem acknowledges, wage indices for LPN and SPN are considerably higher than for other areas, followed by EPN and SSE Southern.

EDF Energy's Customer Density

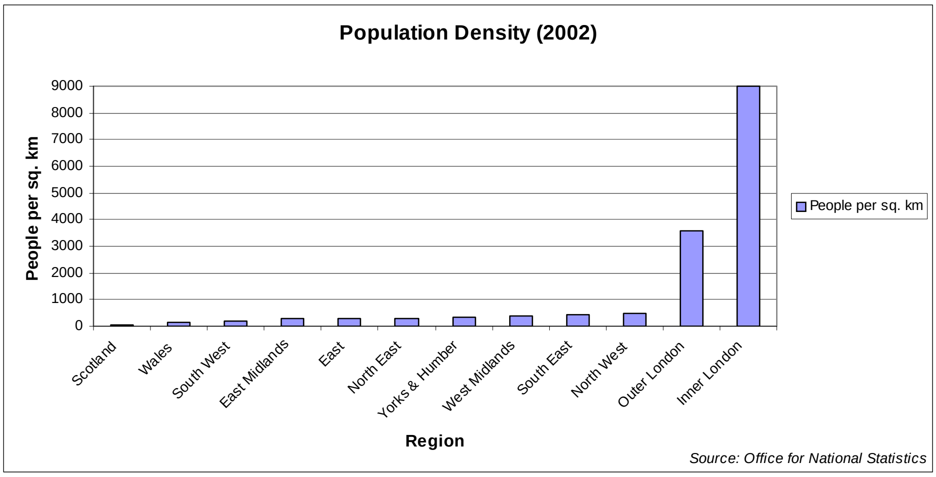
A common misconception is to believe that urban factors only impact LPN. We show below that SPN's (and to a lesser extent EPN's) customer base is dominated by the presence of Greater London, and by cost effects arising from congestion in and around London.

The EDF Energy area within the M25 represents just 7% of total service area but over 46% of our 8 million customers. Half of SPN's underground network customers and a third of EPN's underground network customers are inside the M25. On average overall, SPN has a load density that is 10% of the figure for LPN, and EPN's load density is only 7% of LPN's. However, both SPN and EPN cover substantial areas within the M25, where load is much denser and both DNOs experience the costs of congestion associated with the London area. This is clearly represented below - the darker areas show increasing customer density in the EDF Energy area.





The customer density of inner London (8980 people/sq km) and outer London (3582 people/sq km) is over 31 times and 12 times respectively the non-London average customer density (289 people/sq km). The bar chart below shows this graphically.



All non-London regions have urban areas within them, e.g. West Midlands comprises the Birmingham, Coventry and Wolverhampton conurbation, but no region has a population density anywhere near that of Inner or Outer London. For example, Croydon (within the SPN area) alone represents a city the size of Bristol, despite being a borough of London, and unlike a stand-alone city is within the sphere of influence of the urban effects of London.

London's network statistics represent the impact of this degree of urbanicity. Within this area, despite the shortness of the network, there is seven times the national average amount of cable per square kilometre. In the dense urban areas within the M25, network length does not capture the network characteristics that determine costs, because the amount of equipment, activity and cost depends on other factors, as explained below.

Impact on Costs

Total line length fails to capture urban cost drivers related to congestion. Urban networks undoubtedly have shorter lines and larger substations but they also have:

- More cable joints per kilometre of line due to the number of premises and street furniture.
- More unused connections per kilometre due to frequent changes of use in urban areas.
- More cross-joints and link boxes used as the most efficient way to augment network capacity, by converting radial lines into circuits.
- More utility services (water, gas, telephony/data, and cable TV) in the same roads and footways.
- More difficulty in accessing sites (slower journey times, restrictions on parking, substations located within buildings belonging to third parties, etc).

These urban factors contribute to higher costs, particularly regarding the management of faults. These are best explained by considering their impact on the life cycle of a typical urban fault:

- Increased manual handling resulting from more link boxes and more underground chambers - requiring pairs of troubleshooters to attend at many fault locations.

- Job times lengthened by congestion – traffic jams, parking or access restrictions. Finding suitable parking takes time and is often some distance from the fault.

- Increased out of hours working due to congestion restrictions e.g. red routes, bus lanes, residents' parking (note, parking bay suspension can cost up to £250/day).

- Requirement to find key holders due to high level of multiple-occupancy buildings. This is a significant problem and can involve substantial waiting time. We have to employ three full-time equivalent employees solely to manage and liaise with key holders.

- Urban excavations are considerably more complex than those in rural areas (see illustrative photographs below), requiring more hand digging, more removal of backfill to reduce congestion, a larger area of excavation to cope with more services and cellars, more detailed traffic/pedestrian management, and more effort to get permission to excavate.

- Waste removal is more expensive within the M25.

- Higher re-instatement costs in Central London due to these factors, and also the higher proportion requiring specialist and unusual (i.e. expensive) materials.

Further images with comments explaining the difficulty faced by our DNOs working in London are set out in the Appendix to this response.

Cost Function and Composite Scale Variable

The choice of composite scale variable (CSV) has the effect of disallowing costs (or of creating a revenue windfall) to the extent that it does not match the real cost drivers underlying a particular DNO's cost level. Clearly then, in view of this, and particularly having regard to its statutory duties, Ofgem must either:

- Provide robust evidence for its choice of cost drivers, or if this is not achievable

- Mitigate the risk of error

We are very disappointed that despite Ofgem's awareness of the issue, and its industry workshop on the subject, it has as yet not done either of these things.

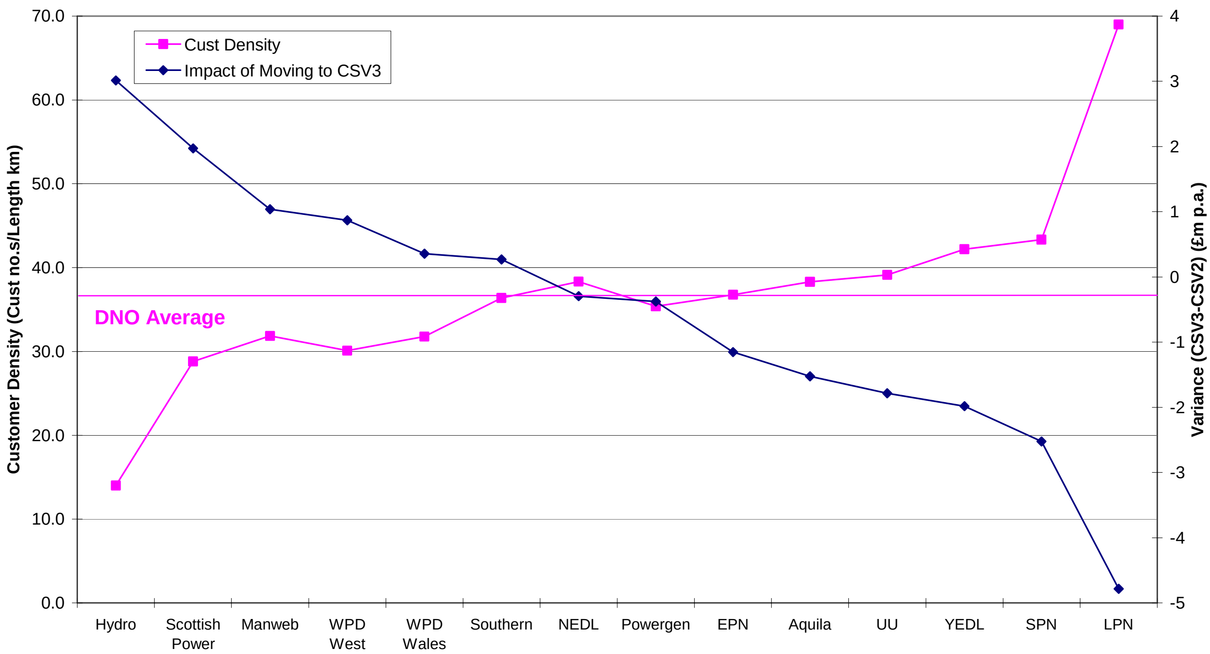
Ofgem has chosen to retain CSV3 in its regression analyses. CSV3 is weighted 50% to circuit length and 25% each to customer numbers and units distributed. CSV2 used at the last review gave 50% weight to customer numbers and 25% each to the other two variables. Ofgem's stated basis for changing the composite scale variable is that companies have allocated approximately 50% of their costs to overhead line and underground cable. However, Ofgem itself admits that this is no evidence at all since it does not necessarily reflect, still less prove, the existence of a causal relationship between cost and driver. Circuit and line costs could be 50% of costs irrespective of the cost driver for those costs.

Ofgem also says that its choice of CSV3 is supported by advice from Ofgem's technical consultants. However, it has not published this advice, sought comments on it, or even summarised it in its September paper. This is most irregular and must be rectified.

It is obvious that either choice of CSV will inappropriately disadvantage companies at the density extremes. CSV2 will tend to disadvantage those companies with large, sparsely populated rural networks whereas CSV3 will disadvantage those companies with dense urban networks. The graph shown below compares the impact on each company of moving from CSV2 to CSV3 with customer density. It clearly shows that the companies with the densest networks are the most disadvantaged by the move to CSV3, with LPN being the most disadvantaged, followed by SPN. Of course, this only reveals sensitivities to different CSVs. Our reasons for urging Ofgem to change its approach and take account of "urban factors" are compelling and are set out below.

The fundamental problem with Ofgem's approach to cost assessment is that Ofgem's regressions do not include enough variables to capture the cost drivers for each DNO. The one-size-fits-all approach is simply not adequate to determine the "right" level of costs for a complex business like a distribution network. We would propose a measure of congestion (or even just of customer density) to capture the cost-raising effects of doing business in the South East of the country. No doubt every DNO can suggest additional or alternative variables that better reflect their own cost drivers, but Ofgem should not regard this lack of consensus as an indication that its own model is as good as any other; merely that it omits a large number of relevant variables. Indeed, it provides no basis for setting revenue allowances without a detailed investigation of the special factors which are not included in the model, but which affect each DNO's costs.

Customer Density vs Impact of moving to CSV 3



We can suggest some of those factors, but it is impossible for us (or any DNO) to say precisely how our DNOs differ from the "typical" position defined by all the DNOs through the regression. In these conditions, it would be very unwise, not to say presumptuous, to conclude that Ofgem's regression provides any kind of realistic assessment of likely future costs. We will therefore expect Ofgem to make due allowance for the data measurement errors and omitted factors when using the benchmarking results to set revenue allowances.

Ofgem has listened to the industry's arguments that merged and total cost analysis needed to be incorporated to reduce the risk of error. Ofgem can, and should, take the same approach to the risk that its CSV is a poor measure of the true cost drivers, at least for the customer density outliers (EDF Energy LPN and SPN and SSE-Hydro). We note that Ofgem is proposing an additional allowance for SSE-Hydro relating to the additional costs of operating in a large, sparsely populated area. In practice, this demonstrates that the results of the benchmarking are unreliable in at least one case and, one must therefore conclude, in all cases. Above all, the results will be at their most unreliable in the case of those at the opposite end of the spectrum of density from SSE-Hydro, i.e. LPN and SPN. . We would therefore expect Ofgem to allow for the special circumstances of all DNOs before defining revenue allowances by reference to the benchmarking results.

Ofgem has provided no evidence to support its move to CSV3 and has provided no evidence to support its implied claim that all companies face similar operating cost conditions (apart from the limited regional adjustments already made).

Ofgem appears to assume that its one-size-fits-all approach to cost drivers works for all DNOs since they all do much the same thing in much the same environment. We show below how this cannot possibly be the case for DNOs serving Greater London. There is compelling evidence (which Ofgem cannot ignore) of urban factors that drive up costs *in* *ways that CSV3 fails to capture*, not only from the material we have provided (including a detailed report from Black and Veatch), but from other regulators and benchmarking studies (for example, the work by PA consulting submitted by WPD). The simple facts of the matter are that exceptional customer density and exceptional urban congestion inevitably require more complex networks and that this complexity inevitably complicates and substantially increases the ongoing work of construction, maintenance, and fault repair. It is therefore impossible to conclude with regard to LPN, SPN (and possibly EPN as well) that the entire gap between actual costs and the benchmark is attributable to unjustified costs or inefficiency that can be eliminated overnight or simply disallowed.

Establishing a Benchmark

We remain concerned, as previously stated, about Ofgem's proposal to adopt an aggressive target defined by an upper quartile benchmark in the face of obvious weaknesses in the benchmarking analysis (in terms of robustness of data, cost drivers, choice of model, and support from bottom-up approaches).

Ofgem provides no response to the arguments set out in DNO submissions (which are in any case only summarised incompletely in Ofgem's annex of responses), and seems to have misunderstood the arguments. Paragraph 4.20 encapsulates the errors in Ofgem's views. Here, Ofgem records the suggestion of DNOs that the benchmark should reflect average costs, but does not discuss the reasoning behind this argument. The summary of responses merely says that DNOs "prefer" an average benchmark and the Update says it is "less challenging" than the upper quartile – all of which is obvious, but not relevant. The point is not that DNOs "prefer" a "less challenging" standard, but that only the average cost standard is compatible with the average rate of return. Ofgem has simply neither recorded nor addressed this argument properly.

Ofgem also overlooks all the criticisms of benchmarking and the caveats about the use of residuals. Ofgem describes its benchmarking as "evidence of achievable efficient improvements" (which is a presumption) and the upper quartile as "sufficiently robust to constitute such evidence" (which is no more than an assertion, unsupported by any precedent or analysis). By overlooking the arguments about benchmarking, Ofgem places an unjustified level of faith in the results (all of which appears to sit rather uneasily with the MMC's comments that benchmarking lacked robustness in the 1997 case of NIE and the Competition Commission's further criticisms in the 2000 case of Mid Kent Water and Sutton & East Surrey Water plc).

Glidepath

Ofgem asserts that it would damage incentives for efficiency if it were to give glidepath for companies to reach the efficient level of costs. We disagree with this statement, since one purpose of discussing a proper glidepath would be to allow a reasonable level of costs, given the benchmarking model's inaccuracies and omissions. Ofgem justifies its proposal by arguing that the use of an average cost of capital implies that some companies will receive below average returns. However, Ofgem's proposal to base the efficient level of costs on the upper quartile is not consistent with offering an average cost of capital.

In paragraphs 4.22-4.24, Ofgem combines two arguments in one: whether the standard should be average costs or the upper quartile; and whether there should be a glidepath. In paragraph 4.23, Ofgem argues as follows: the use of average costs would mean some companies would have below-average returns; therefore it is not necessary to ensure that all companies earn the full rate of return; using the upper quartile also ensures that some companies have below-average returns; therefore the upper quartile is as good as using average costs. Here, of course, Ofgem is addressing a point that is not contentious – that some companies may have below-average returns, if proven to be inefficient – whilst failing to discuss a highly contentious decision – *how many* companies should get below-average returns.

In paragraph 4.24, Ofgem says that a glidepath would offer "additional revenue for companies that are shown to be less efficient", which prompts several responses. First, Ofgem's benchmarking has not shown companies to be efficient, less efficient or inefficient, because it suffers from so many flaws. Second, what matters in terms of incentives is not whether a scheme offers additional revenue, but what it means for the rate of return. Ofgem can still ensure that "companies shown [objectively] to be less efficient" receive a lower rate of return, even if they receive more revenue than other (supposedly more efficient) companies (i.e. removing the glidepath is a blunt instrument approach to modifying returns). Thus, Ofgem's point does not provide any reason for abandoning a glidepath.

The lack of a glidepath implies that Ofgem is stating categorically that the benchmark defines the level of allowable costs in 2002/03, not a target that companies should aim for by, say, 2009/10. In this respect, the benchmark is even less defensible than in previous usages since Ofgem has no proper evidence that the extra costs are due to inefficiency rather than other factors. This concern is compounded by the large change in relative efficiency positions since DPCR3.

Ofgem also appears not to have undertaken any reality checks, for example by developing a specific understanding of the steps taken by companies to achieve their supposed 2003/04 relative efficiency positions.

Setting the benchmark as a target for the future throws the emphasis onto likely rates of cost reduction, but applying it now removes this scope for judgement and a more reasonable approach.

Frontier Shift

We are pleased to see that Ofgem has realised that 2% per annum was not a sustainable target for future frontier shift. We are also pleased that Ofgem has recognised that its consultant's view of TFP growth included both catch up and frontier shift. However, we are concerned that Ofgem has still overestimated the scope for future improvement.

The ENA wrote to Ofgem on 8 October 2004 setting out the concerns of all DNOs. In particular that:

- Future UK productivity assumptions have been understated;
- CEPA overestimates the impact of the privatisation effect on future productivity;

- Frontier shift and catch up elements have not been separated.

ENA concluded that after assuming an equal split between frontier shift and catch-up, outperformance of the economy as a whole (i.e. general productivity improvements captured within RPI) is expected to be modest (less than ½% p.a.).

We are also concerned about incentives. We understand that superficially both carrots and sticks can appear to have the same marginal incentive power. However, efficiency improvement does not come without cost, whether it is the cost of funding specific initiatives and improvements in technology, or the cost to shareholders of incentivising management. Ofgem's current approach has the effect of disallowing such costs without justification. We believe that this is why Ofwat has taken a more balanced approach to incentive reward.

Total Cost Analysis

Ofgem has not included capex expenditure pre 2000 in its analysis of total costs as:

- The reported data may not be on the same basis as the post 2000 data; and
- Recent capex may have a bigger impact on opex spend than historic capex

We continue to fail to understand why it is appropriate to exclude historic capex from the analysis, which will have an impact on opex expenditure in 2002/03, but to include future capex (i.e. post 2002/03), which will not. Even if Ofgem judges that it cannot rely on historic data, it should at least mitigate to some extent the risk that some companies have significantly different past capex/opex profiles that otherwise disadvantage them in Ofgem's partial analysis of costs - most notably SPN.

In Figure 4.3, Ofgem presents a regression described as "total cost analysis", but in fact it does not compare costs, but only total expenditures (opex plus capex). Capex can vary cyclically over long periods, so comparing companies at different points in the cycle does not capture differences in the efficiency with which they are being managed (or have been managed in the past).

Paragraph 4.31 discusses total cost analysis using historical information. Ofgem dismisses this version on the grounds that capex may not be "reported on the same basis", although Ofgem does not say whether the difference in reporting basis arises between companies or between years, or whether such differences would be significant for the results. However, Ofgem notes that using historical figures does affect the positions of SPN and SSE-Southern (moving SPN to the frontier and SSE-Southern well away from it), which is to be expected, and which ought to give Ofgem grounds for reconsidering its treatment of both companies. However, Ofgem simply discards the analysis.

Ofgem's consultants (Cambridge Economics Policy Associates) noted that Opex "only" benchmarking will have serious affects on companies who have historically invested (CAPEX) less than the industry average (e.g. EDF Energy SPN). "Not only will its regulatory capital value be relatively low, but would appear inefficient on opex benchmarks, as a result would be expected to reduce costs faster". CEPA, in their analysis used the totex variable:

$$\text{totex} = \text{base opex}_t + \text{depreciation}_t + \text{ROC}_t \times \text{RAV}_t,$$

which has previously been supported by EDF Energy. They also stated that if it is difficult to construct an appropriate totex variable then it should be used to assess the divergence in opex performance rather than acting as a benchmark. Ofgem does not appear to have followed the guidance of its consultants.

It is obvious that work needs to be undertaken to develop a better definition of capital consumption since the inability to properly deal with capex/opex trade off is a major weakness of Ofgem's benchmarking process and will inevitably lead to sub-optimal investment choices by companies - which cannot be in customers' long term interests.

Data Envelopment Analysis

DEA allows the weighting of the CSV components to adjust to optimise the efficiency score for each DNO. This flexibility offers a significant advantage in conditions where differences in customer density affect costs. DEA can take account of differences in customer density by changing the balance between (1) the customer numbers or units delivered and (2) circuit length.

Ofgem dismisses the use of DEA on the grounds that the results "imply that the impact of different factors varies more across DNOs than appears to be plausible", but has not published the results of its analysis, nor has it set out the standard by which it concluded that these were not plausible. Since we believe that different factors affect DNOs in different ways, we would expect a wide variation in the relative weights of different factors and can see no reason why Ofgem should reach such a firm conclusion without any discussion or public scrutiny of its reasoning.

In late 2003 Ofgem published its consultant's report on benchmarking. In this, CEPA suggested that an appropriate efficiency frontier would be set through the use of DEA and COLS (regression) in combination. In particular, CEPA proposed that emphasis is placed on DEA scores while COLS is used to assess the appropriateness of the outputs. Ofgem has used COLS as the basis of their efficiency score but have not used DEA in the way proposed to assess the validity of their model. We believe that DEA results should be used to define a plausible range of benchmarking results taken into account when asserting that differences from a frontier are due to inefficiency.

Vegetation, Exceptional Events and Quality Improvement

We support Ofgem's decision to retain its approach of making adjustments for tree-cutting costs, although we are concerned that this adjusts costs to the national average and will therefore be overgenerous to some but insufficient to cover EDF Energy's costs in the south-east. In our view, Ofgem's modelling requires further improvement if it is to be used in the normalisation adjustments that impact efficiency assessments generally.

Comparison with 2003/04 analysis

Ofgem's contention is that there is no evidence that the 2003/04 costs are materially different from the 2002/03 costs. However, we would have expected Ofgem to use this data to ascertain if its view on the future productivity of the industry was robust. Based on Ofgem's analysis it would be expecting the industry costs to be 1.5% lower in real terms in 2003/04. There is no evidence that companies have been able to reduce costs to the level that Ofgem's position on future productivity growth would suggest. It should also be noted that two of the companies who have been able to reduce costs in real terms in 2003/04 have recently merged; an option which the majority of other companies have already expended.

Work by Ernst and Young

It is wrong of Ofgem to state in its paper that for EDF Energy "potential cost reductions accounting for a significant proportion of the difference between 2002/03 actual and the proposed allowances were identified by the limited scope review conducted by Ernst and Young". In fact the draft Ernst and Young report (we have yet to receive the final report) identified at best £12m - £20m of potential savings. We identified a number of areas where we believed that their findings were inappropriate or double counting existed, but we have not yet seen a final report.

Of the potential amount in the draft report, a proportion relates to capitalised costs and should not therefore be compared to the £55m opex difference identified in Table 4.3 of Ofgem's paper. On the basis of conservative assumptions (i.e. in favour of opex) Ernst and Young have in fact only identified around 10% to 18% of the opex difference. We would strongly argue that this does not amount to a "significant proportion", as Ofgem states, and that the advice from Ofgem's own consultants therefore contradicts the results of the benchmarking.

Mergers

Four DNOs have been benchmarked as non-merged companies with regard to 2002/03: they are Central Networks East, Central Networks West, United Utilities and EDF Energy (SPN). As of now (October 2004) only United Utilities remains unmerged with other DNOs.

Although we have strong concerns with Ofgem's benchmarking set out elsewhere in this response, we have no issue with the proposal that recently merged companies be asked to achieve the deemed level of efficient costs established by other DNOs, including other singletons (such as CN East). However, we do not agree with the speed of cost reduction implied by Ofgem's glidepath (or lack thereof).

At the time the LE Group acquired SPN in August 2002 we took into account Ofgem's revised approach to mergers, and in particular that merger savings would be treated in a similar manner to other savings at future price control reviews. However, we also expected Ofgem's policy of permitting savings to be retained for five years, and for this to be facilitated by the continuation of the previous practice of allowing companies a period of time to catch up with the target efficiency level. These policies, together with what was said by Ofgem at the time, gave rise to a legitimate expectation that the benefits of the merger (net of integration costs) would be retained by us for a period of at least five years.

Ofgem's new and more aggressive policy of requiring immediate catch-up was not part of our understanding. It does not have any precedent in standard regulatory practice, or any rationale in economic theory, or any support from robust empirical analysis. The policy could not have been foreseen from the behaviour of Ofgem or from that of other regulators, nor indeed from what was said to us by Ofgem at the time of the merger. Removing any glidepath therefore represents a change in regulation that represents significant regulatory risk. In future, we would have to assess the incentives implied by Ofgem's statements with this risk in mind, which will not be in consumers' interests. To remove this unnecessary risk, Ofgem should allow a cost glidepath up until the fifth anniversary of the SPN acquisition (August 2007) including an amount to cover restructuring costs.

Rates

We are pleased to see that business rates on network assets will be treated as a pass through cost, as we believe this to be the appropriate treatment.

Capital Expenditure

PB Power Reports

Ofgem has used PB Power's work as the cornerstone of its work on capex. It is therefore surprising and disappointing that Ofgem has neither responded to comments made on the work, nor made updated reports available.

Resilience and Worst-Served Customers

Ofgem states that it does not believe that resilience schemes are justified, but that the sliding scale mechanism allows companies to undertake this expenditure where they can justify it. This is not correct. The sliding scale mechanism is intended to partially fund base case forecast expenditure. DNOs will not undertake investments that risk disallowance from the RAV.

Ofgem's discussion confuses the issues of "worst served customer" and "resilience". Resilience is not just about customers in rural areas at the end of very long feeders. Resilience is about reducing the volatility of QoS performance (rather than the underlying trends) by mitigating all of the most serious effects of potential faults. This can involve many different types of work, including work in urban areas where limited interconnection or alternative sources of supply are thought to pose a resilience issue, or perhaps where access is a problem (for example, where EHV cables run alongside railway lines with limited access for DNO staff). The cost per customer reference might provide a useful way to appraise investments aimed at "worst served customers" but it is irrelevant to investments in resilience where many thousands of customers who have not complained would in future benefit in storm conditions or after a major incident in an urban area.

We remain disappointed that Ofgem has not engaged in any substantive debate over resilience throughout this process. If this aspect of a prudent investment strategy fails to receive the attention that it merits, it will be impossible for us to devote resources to it and customers will not receive the benefits as a result.

ESQCR

While the majority of costs might be expected after 2008, significant costs will be incurred in the period before this date. A transparent mechanism is needed for recovering these costs, which to a large extent will depend on the DTI's definition of 'immediate danger'. The obvious solution is for Ofgem to adopt the simplified form of limited re-opener set out in the recent submissions of the industry side of the joint legal working group in relation to draft special condition A3.

Fluid Filled Cables

We welcome the opportunity to discuss the issue of replacement of fluid filled cables outside of the main review process. However, we would ask Ofgem to ensure that these discussions will have progressed sufficiently to enable Ofgem to publish its findings in the Final Proposals paper in November.

We believe that the mechanisms under discussion with Ofgem will enable Ofgem to accept our replacement proposals and confirm the necessary ring-fenced allowances in the November proposals. This will enable EDF Energy to commence this important thirty year replacement programme during the forthcoming price review period.

Sliding Scale Mechanism

Ofgem still proposes to penalise companies for failing to predict PB Power's forecast of their capex, which is a curious standard to set and presumes a great deal about the robustness of PB Power's model and the accuracy of PB Power's forecasts. It seems perverse to penalise a company for something as subjective as the gap between its stated opinion about future capex and someone else's opinion about future capex. There is no reasonable way for companies to predict what PB Power is likely to forecast, as there is no standard way of forecasting capex, so the incentive does not encourage more "accurate" forecasts, only lower ones.

With regard to the accuracy or objectivity of PB Power's forecasts, Table 4.8 in the September update shows considerable variation in percentage errors and the 100% figures seem unlikely – in fact, they may represent cases where PB Power accepted DNO forecasts on the grounds that they were lower than their own. The range of figures (even excluding EDF Energy's) does not give much confidence in PB Power's forecasting abilities.

We are also concerned that changes to our capex forecasts have not been reflected in our position within the sliding scale mechanism. This seems unreasonable and inconsistent, particularly with respect to changes made in the light of better information with regard to the definition of Ofgem's base case. We also observe that the notes to Table A9 refer to "amendments to forecasts by some DNOs" suggesting that some DNOs have been allowed to change their forecasts and their position in the sliding scale. The equivalent opportunities should now be given to EDF Energy and we assume that Ofgem will adjust our position in the light of our discussions of capex.

Ofgem's decision to impose a penalty on EDF Energy appears related to a perceived risk that we are asking customers to pay twice for a proportion of underspend from the current period (see p4.56 of the September Update). Such a concern is unfounded and unjustified. We strongly contend that our past expenditure has been efficient and without material detriment to both quality of supply and resilience.

We remain concerned that a company's incentive rate for opex and tax will be set relative to a comparison of PB Power's view of required capex with that of the company. Consequently, companies will have differential incentive rates for opex. This means that some companies will be able to reduce costs faster than other companies over the DPCR4 period, as relatively more efficiency programmes would be NPV positive. This would seem to rule out comparative analysis as a tool for the next price control, as it would discriminate against those companies with lower incentive rates by inappropriately judging them less efficient, whereas in fact they will merely have been reacting efficiently to the incentives on offer. If Ofgem has a forward-looking belief that DNOs should behave in accordance with possible incentives at the next review and not just in accordance with incentives during the current regulatory period, then there would be little purpose in setting the short-term incentives.

We also believe that the application of the pre tax return is discriminatory. For example:

- According to Table 4.7, if Company A's capex forecast agrees with PB Power's then it receives a 40% incentive rate, a positive pre tax return and a capex allowance of 105%. However, if it needs to spend 40% more than the forecast it should be penalised (according to Ofgem's approach) to the extent of 14%[1] of the value of the overspend, based on Ofgem's stylised example. However, the actual penalty is 11.5% due to the offsetting impact of the additional pre tax return.

- However, if Company B disagrees with PB Power and believes that it needs to spend 40% more than PB Power suggests it gets an incentive rate of 20%, a negative additional pre tax return and an allowance of 115%. If it spends its forecast (i.e. 140% of the PB Power assessment) it should be penalised by 5%[2]. However, it is penalised 7.4%, due to the impact of the negative additional pre tax return (again based on Ofgem's example).

Therefore, under the proposed mechanism a company which is determined to be a "good forecaster" ex ante but needs to significantly overspend gets to keep its additional pre tax return. However, a company which is determined to be a "poor forecaster" ex ante but subsequently spends its forecast is still penalised by having a negative pre tax return. This would appear discriminatory and must be addressed.

A company may need to overspend its original forecast due to unforeseen circumstances. Given that Ofgem's consultants agreed with its forecast, it would be inappropriate for the company to be penalised retrospectively, assuming that the overspend was efficient. However, if a company was judged a "poor forecaster" but subsequently needs to spend above its allowance, then it should not be subject to a negative pre tax return as well as incurring a penalty.

[1] (140-105)*0.4 = 14

[2] (140-115)*0.2 = 5

Incentives

We said in our response to the June paper that setting opex incentives by reference to a company's ability to guess the result of PB Power's limited capex modelling was irrational. Our view on this has not changed. PB Power's forecast does not offer the objective justification required to allow such discrimination, in the form of different treatment of similar behaviour by DNOs. Furthermore, we believe that weakened incentives on opex will significantly reduce the number of viable efficiency improvement projects, which will not be in customers' long term interests.

Ofgem has no need to use opex incentives as a stick to ensure the DNOs work towards robust data collection arrangements, and has more than sufficient powers to achieve this. In any case DNOs already well understand the regulatory risk that results from weak benchmarking and are keen to work towards resolution. We would ask that Ofgem restores opex incentives to their current levels and only reduce that if agreement of data collection arrangements cannot be reached.

Ofgem's intention to equalise incentives on opex, capex and tax represents a major change to the core structure of incentives applicable to DNOs. A change of such magnitude deserves in-depth consultation so that a robust framework is developed which all stakeholders understand, and which is predictable in its outcome. It is therefore most unusual and unexpected for Ofgem to devote so little space to this in its update document. Clearly, it would not be helpful for DNOs to have first sight of the details of the scheme as part of the final proposals.

We describe below (under the heading Tax) difficulties that arise with Ofgem's proposed adjustments for gearing. There are other key aspects that need clarification too:

- How will overspends by treated?
- How will incentives be equalised?
- When will rewards and penalties be settled?
- How will QoS allowances (for CML improvement) be incorporated?
- How will expenditure on low-loss equipment be treated?
- How will corporate costs be assessed?

Regarding the choices for settlement outlined in p4.74, we prefer settlement within the period, as the outcome will be more certain.

Financial issues

Base revenues

The Base Revenues used for the calculation of P0 have not been adjusted for changes in volumes between 2004/05 and the first year of the DPCR4 period (2005/6). This incorrectly states the impact of the year-on-year change to average DUoS prices which also take into account volume changes. The impact on EDF Energy's DNOs has therefore been an overstatement of P0 increases (or understate P0 reductions) by around 1%.

The P0 increase for SPN has been further overstated through the input into Ofgem's financial model of an incorrect Base Revenue figure. We have separately advised this direct to Ofgem's financial team.

Pensions

Allocation of Liabilities to the Regulated Business

An increased allocation of pension liabilities to SPN is required as a result of the company specific Seeboard transfer scheme. This scheme was approved by the DTI as being in the public interest after review by Ofgem. As a matter of law, SPN carries 99% of the liabilities of the Seeboard Group of ESPS and the allocation should be increased to reflect this. Please refer to our letter of 6 October 2004 to David Gray, which sets out this issue in full.

Ofgem's pragmatic approach to determine how liabilities should be split between the regulated and non-regulated businesses should not ignore hard evidence of company-specific liabilities which were imposed by operation of law and cannot now be reduced or renounced.

Underestimate of EPN's Pension Deficit

As part of the 2004 London Group of ESPS valuation process, EDF Energy asked its actuary (HBW - Hewitt, Bacon & Woodrow Limited) to provide information on the liabilities associated with ESPS members who transferred from TXU in December 2002. This provides the actual ESPS liability attributable to EPN.

HBW have now provided this information. The actual ESPS liability of ex-TXU staff equates to £207m which is 16% of the total liabilities of the LE Group of ESPS. Ofgem has assumed that only 13% of the LE Group liability is EPN and this needs to be increased in the light of the actual valuation data.

The correct figure that should be used for EPN's share of the ESPS deficit is £35m. This compares to Ofgem's assumption of £29m (prior to reduction by 1/13th). The November document needs to be amended to reflect the actual EPN liability.

2004/5 Pension Contributions

It is incorrect for Ofgem to disallow a proportion (1/13th) of pension deficits for 2004/5 contributions. Deficit repair does not start for any of our three DNOs until April 2005, in line with the 2004 ESPS triennial valuations. This was the subject of a letter dated 5 October 2004 to David Gray from ENA, which EDF Energy fully supports.

The issue is compounded further by spreading the remaining deficit over 13 years, rather than 12, from the start of the price control period.

Shorter Average Future Working Life for SPN

The use by Ofgem of an industry average remaining service life of 13 years for SPN is incorrect and needs to be corrected. The figure used by our actuaries in the 2004 valuation is 10 years. This shorter average remaining service life is a function of the profile of the active membership, calculated by the scheme actuaries. We refer you to the letter addressed to Carl Hetherington dated 31 August 2004 from Keith Lelliot, Scheme Actuary, of HBW. We do not expect Ofgem to override such estimates without proper evidence.

Ofgem should be able to obtain scheme specific figures for all DNOs.

The impact of Ofgem's generic assumption is to understate SPN costs by at least £1.5m a year.

Normal Contribution Rates

As part of the ongoing valuation exercise, normal contribution rates have increased. Ofgem should therefore amend its calculations to reflect the actual contribution rates to be paid. The latest valuation information indicates the following rates will apply to March 2008, with the actuary's estimate of rates for 2008/9 and 2009/10 in the next triennial period (we will provide updated data to Ofgem under separate cover).

Annuity Rate used for Annual Deficit Allowances

There would seem to be no justification for any inconsistency between the discount rate underlying the deficit repair contributions and the discount rate used to calculate the deficit in the first place.

Ofgem is using an annuity rate for pension deficits of 5.5%, based on an average of DNO FBPQ submissions (Table 9). The Table 9 figures were based on FRS17, <u>not</u> funding, liabilities. The 5.6% p.a. used in EDF Energy's FPBQ Table 9 submissions was the FRS17 discount rate based on market conditions at 30 November 2003.

If Ofgem continues to use a 5.5% p.a. discount rate to calculate deficit repair payments, then deficits should be recalculated on that basis, which would result in much higher deficits (particularly for the LE Group scheme, where the increase could be as much as £100M).

The discount rates for deficit repair are a combination of the pre-retirement and post-retirement discount rates used in the valuation, combined in proportion to the amounts of pre-retirement and post-retirement liabilities. We will forward under separate cover the rates on which actual cash contributions will be calculated for our DNOs and which should underlie the Ofgem allowances.

We refer you again to the letter addressed to Carl Hetherington dated 31 August 2004 from Keith Lelliot, Scheme Actuary, of Hewitt, Bacon & Woodrow Limited.

Treatment of ERDCs

EDF Energy continues to believe that no ERDCs should be disallowed by Ofgem. Applying past investment returns to disallowed ERDCs compounds the issue. The impact of Ofgem's calculations is effectively to disallow 40% of ERDCs rather than 30% (a figure which we consider to be too high in any case). We urge Ofgem to reconsider its position on ERDCs and, at the very least, to not apply past investment returns to past ERDCs.

Capitalisation of Deficit Repair

We are concerned that Ofgem is capitalising 60% of the annual deficit repair cost. This will defer the receipt of cash by DNOs over a period of more than 20 years, whereas the scheme trustees will require the money over just 10 or 13 years.

This will worsen the forecast cash-flow issues of EDF Energy (SPN) and to a lesser extent of EPN.

We are also concerned that we may not be able to replicate this treatment in our statutory accounts, forcing this cost to be treated as opex, resulting in a mismatching of costs and revenues and significantly reduced operating profits.

Tax

Opening Balances

Ofgem notes that adjustments to balances arising from group tax strategies or from non-distribution assets "merit consideration in principle", but that it would be difficult to adopt a consistent approach and that some of the proposed adjustments would be retrospective.

Given that consideration of historic tax pools is inevitably backward looking, Ofgem's point about retrospectivity seems to be a weak one. The point about consistency of approach depends, as in so many other areas of the review, on the evidence provided by the company concerned. However, variable quality of evidence does not justify Ofgem avoiding appropriate judgements about what is a fair allocation of value between customers and shareholders.

With regard to non-DNO related tax pool balances (including those that result from group tax strategies) we also observe that consistency must be achieved with Ofgem's treatment of pensions, where Ofgem has proposed an allocation (regarding non-DNO liabilities) in spite of having evidence of variable scope and quality.

We have provided Ofgem with evidence of the impact of specific tax management actions taken by EPN that we believe distort the forecast tax payments during the DR4 period compared to other DNOs. We believe that the opening tax pool balances should be adjusted to exclude the impact of these actions (recent correspondence with Carl Hetherignton refers).

Categorisation of Costs for Tax Purposes

We are pleased to see that Ofgem has moved some way towards a more appropriate balance between cost categories.

Incentives and Risk-Sharing

Our comments on the proposed incentive mechanism covering opex, capex and tax are set out elsewhere in this response.

The proposed incentive mechanism would seem to provide incentives for companies to achieve the arbitrary 60% assumed gearing level but penalises higher gearing levels:

- Ofgem has already said that it will adjust actual tax down to a level consistent with 60% gearing where actual gearing is lower than this figure.
- With regard to gearing levels above 60%, the DNO concerned will incur increased interest payments, thus increasing its tax shield. Actual tax would be reduced compared to Ofgem's assumption (and would not be adjusted upwards by Ofgem) and an incentive reward would be due. This reward would be reduced to a level determined by that company's position on the sliding scale mechanism (currently ranging between 24% and 40%), so that the majority of the tax saving would be taken away. However, as interest costs are outside of the incentive mechanism they are not subject to any equivalent adjustment and would be borne in full by the DNO.

Therefore, the effect of Ofgem's proposals is to distort gearing decisions and to make gearing above 60% a less viable option.

We believe that Ofgem should not attempt to interfere with business decisions on appropriate gearing levels for individual DNOs. We accept that for calculating the tax incentive Ofgem will need to adjust interest costs onto a comparable basis with the 60% gearing assumption used to set the tax allowance. However, it is important that this is two-way and that adjustments are made for gearing levels both above and below 60%.

It would be useful for Ofgem to set out what checks are proposed "to avoid over-allocation of tax costs to the distribution business"[3].

Regulatory Asset Value

We have provided further evidence to Ofgem regarding RAV adjustments in respect of:

[3] p5.28

- Inter-company margins and non-operational depreciation
    - To be updated using 2003/4 actual data
    - 24Seven margins prior to acquisition of EPN from TXU should not be adjusted
- EPN Pension adjustment in 2000/1 and 2001/2

The above adjustments which reflect the more accurate data provided to you need to be incorporated into the RAV calculation prior to the final proposals.

We continue to oppose Ofgem's proposal to retrospectively apply industry average overhead capitalisation policies, effectively re-opening DPCR3. In particular, Eastern (now EDF Energy EPN) was an above average capitaliser at the last review and this helped set Ofgem's efficient frontier for DPCR3 Opex. EPN accepted DPCR3 on the basis of its accounting policies at that time as part of a price control package and it is not appropriate for Ofgem to now apply alternative rules retrospectively. Our concerns also apply to LPN and SPN, although the quantum of adjustment involved in their case is smaller.

Financial Profiles

Ofgem correctly identifies that the updated proposals continues to raise financing (cash-flow) issues with respect to EDF Energy (SPN).

The reason for SPN being in this position arises from its relatively small RAV compared with that of other DNOs. Indeed, it is worth noting that on a per customer basis SPN's RAV, when it was first set on the basis of the flotation value in 1990/01, was by far the lowest of the England and Wales companies (just 65% of the average, excluding Seeboard). By 2002/03 this position was largely unchanged, with SPN's RAV per customer being 64% of the average, despite Ofgem accelerating its depreciation during DR3. Clearly, therefore, recent capex spending profiles and accelerated regulatory depreciation have had little adverse impact.

The licence and statutory regime under which SPN (and other DNOs) operates means that it is financially ring-fenced and must be considered on a stand-alone basis. This has been the case from some time before the LE Group's merger with Seeboard in the summer of 2002, in particular from the date of the transfer scheme and the separate licensing of distribution entities (1 October 2001).

We were entitled to expect that ongoing regulation, in particular through the Authority's financing duty, would ensure that, at an efficient level of costs, SPN could continue to be financed. Furthermore, SPN is prevented from giving or receiving a cross-subsidy from any other part of EDF Energy (including our other two DNOs, LPN and EPN). This means that the solution to the SPN financing challenge must come solely from the resources legitimately available to it and to it alone.

The regulatory approach to addressing financeability issues taken at DPCR3 was to accelerate the regulatory depreciation profiles for Seeboard, Swalec, and Norweb. In other words, for these companies customers were asked to pay depreciation charges in advance to ensure that appropriate credit ratings could be maintained. Shareholders were not asked to make good the projected shortfalls. This policy was described in Ofgem's final proposals document as:

> "…a means of increasing certainty with respect to the financial position of the distribution business and the path of prices in the long term. The benefits of this will be felt by both customers and companies"[4]

However, further accelerating depreciation is not a viable long-term solution, as is demonstrated by the recurrence of the issue for SPN at the current review (in the context of increasing capex requirements). It is for this reason that we are proposing a financeability adjustment of the kind proposed by Ofwat[5].

In terms of the impact that a financeability adjustment might have on customers, we believe that this will be understood as being necessary to restore SPN to a financially sustainable basis, so that it can continue to meet customers' expectations. The fact is that, as a result of its starting point and subsequent efficiencies, SPN's distribution prices have always been at the low end of the scale and will remain so.

Cost of Capital

Ofgem's intention to leave determination of this vital price control element to the final proposals is unfortunate in that it will leave no time for debate and comment.

The 14 October letter from Ian Marchant (SSE) sets out the industry's position, including that of EDF Energy. In particular, it is clear that there is little perceived difference in the riskiness of water and sewage companies compared to electricity distribution. Ofgem will distort the behaviour of the capital markets if it proposes a materially different cost of capital to that set out by Ofwat in its draft determinations.

We have provided substantial evidence that the cost of capital is higher than Ofgem's estimates, in the form of reports by NERA using the CAPM and DGM methods. We will expect to see that evidence taken explicitly into account in Ofgem's final proposals and would wish any decision to reject the evidence in those reports to be explained in detail.

In addition Ofgem's focus on price control "sticks" and reduced incentives has left little scope for DNOs to outperform cost and quality targets, with the result that the ability to earn the true cost of capital in past periods will no longer be available. It also worth pointing out that even Ofgem's update document contains proposals that will leave the companies exposed to substantial regulatory risk. Investors will demand a higher rate of return to cover this risk to cost recovery, unless Ofgem provides a strong indication of the rules to be applied in the future, in at least the following areas:

- Meter asset charges which expose cost recovery to the risk of competition towards the end of the assets' lives;

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[4] p5.34 Final Proposals, Ofgem, December 1999

[5] p195 Future Water and Sewerage Charges 2005 – 10 draft determinations, Ofwat 2004

- Benchmarking (an entirely subjective process that changes at every review and produces unpredictable results);

- Lack of glidepath (a new and unprecedented development which places more reliance on the subjective results of benchmarking than they merit);

- Uncertainty over the treatment of wage costs (clearly higher throughout the South East, but still open to consideration, as far as Ofgem is concerned, on the vague and non-analytical grounds that they might be offset by lower costs in – unspecified – other areas);

- Uncertainty over the precise treatment of capex underspends in one regulatory period, and the possibility that they may be used as a reason to disallow capex forecast for the next regulatory period;

- Uncertainty over the treatment of capex overspends during and at the end of the next regulatory period.

Appendix

Examples of how Urban Factors arise

The images below illustrate the some of the urban conditions we face in carrying out our work (opex and capex) in London and which lead to urban factor costs, none of which are captured by the line length variable used in Ofgem's regressions. Although these conditions can arise in other GB population centres, the incomparable scale of London's urban area means that there is little respite for DNOs operating there.

Image 1: Shows the extensive size of excavation in footways often required to identify LV cables amongst those of other services (British Telecom in grey and other telecoms operators in green). All require careful hand excavation to avoid damage. Excavation close to the roadway constrains working space.

Image 2: Clearly shows telecom assets lying above our power cables. Careful hand excavation again required. Note block paving surface (common in many London streets) which is more time consuming to lift and reinstate.

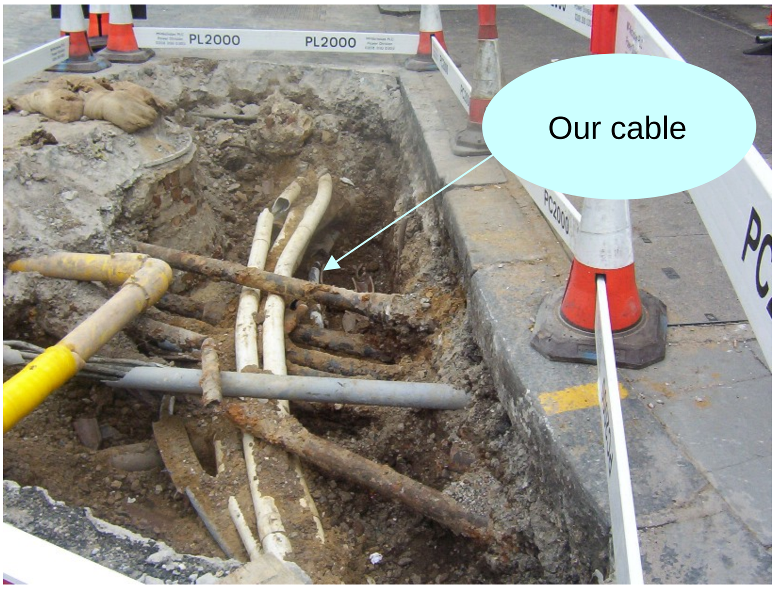

Image 3: Shows the difficulty associated with locating the correct power assets among a nest of other older equipment. Often these have to be placed in the roadway as the footways are too congested. The items that can be identified include: sewage manhole and cover (under sandbags), BT cables (grey), telecoms/data/cable TV (white), gas pipe (yellow). The rusted steel pipes seen could be gas, old electricity cast iron ducts, or old BT ducts, and are above our steel wire armour cables (at the bottom of all this). Hand excavation in such circumstances is clearly very time-consuming.

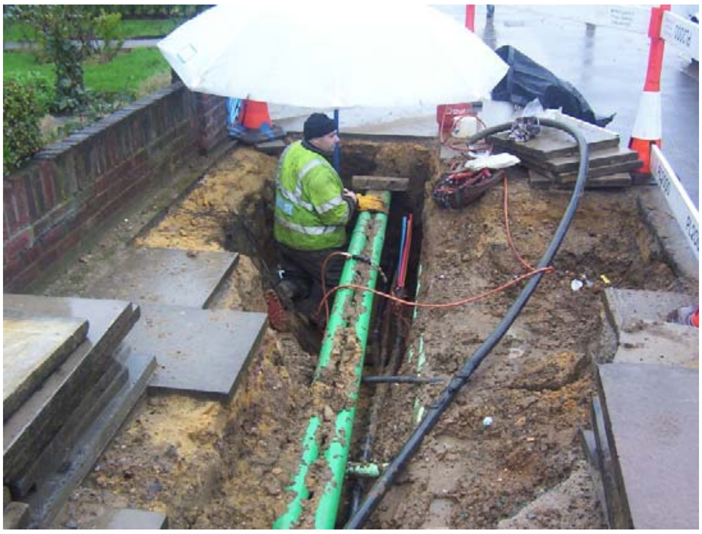

Image 4: Shows the difficulty of jointing power cables underneath telecommunication cable ducts.

Image 5: Link box at junction showing scale of excavation, lack of immediate parking and space for spoil. Orange ducts are for highway authority traffic control equipment. Hand excavation essential to avoid damage to these.

Image 6: LV cables (in centre showing joints) under/amongst telecoms infrastructure (green and grey). Hand excavation required and little space for our operatives to stand/work in.