SECTION 1 – Key points

This commentary sets out the views of EDF Energy on the key issues arising from Ofgem's Methodology and Initial results paper published on 8th May 2009 within the electricity distribution price control review process.

Overview of FBPQ forecasts

- We note that the other DNOs generally have not forecast an increase in the support costs associated with capex work (designers, project managers engineering management and clerical support, training, stores and IT) despite predicting substantial increases in capex volumes. This does not appear credible and would seem to be evidence of different accounting and contracting strategies. EDF Energy's best practice open-book contracts provide Ofgem with complete transparency of capex support costs.
- Making accurate long term forecasts of the level of required load-related expenditure is very difficult in the current economic climate. However, it is important that DNO's have a robust estimate of the baseline load related expenditure. We note, with some surprise, that only CE, ENW, EDF Energy and Scottish Power have reduced their gross load related expenditure from the Draft FBPQ (August 2008). Although we recognise that there may be other drivers for a rising estimate of gross load related expenditure, we are surprised that this is the case against the backdrop of the deterioration in the economic climate. Furthermore, we would expect DNOs to have further adjusted their June FBPQ update to reflect the change in the consensus view of the economic climate.

Operational cost assessment methodology and results

- EDF Energy welcomes Ofgem's efforts to develop a more sophisticated approach to comparative benchmarking, which takes advantage of the Regulatory Reporting data collected during DPCR4.
- Whilst we acknowledge the significant step-forward that this represents, it also places much greater demands in respect of:
    - ensuring that cost data is robust and has been reported on the same basis
    - making adjustments and exclusions which reflect the legitimate differences between the environments within which the DNOs operate
    - identifying cost drivers which genuinely explain the activity observed
    - selecting and applying appropriate statistical methods, such that the outcomes have the confidence of the DNOs and other stakeholders.
- Our experience to date is that there are still significant issues with the integrity of cost data, and despite Ofgem acknowledging some of these,

Ofgem appears unwilling to challenge the relevant DNOs. Equally Ofgem has not succeeded in preparing a well-defined set of cost drivers which explain the different aspects of the DNOs operations.

- We would propose the introduction of some form of differentiated treatment in defined areas, e.g. trees, which recognises the investment made by some DNOs in providing comprehensive and independently audited data to Ofgem.
- The difficulties that Ofgem is experiencing in developing a reliable set of cost data and associated drivers lead us to conclude that it will struggle to deliver a robust comparative benchmarking model to be used in the setting of allowances for DPCR5.
- Ofgem's response to EDF Energy's well-evidenced claims for regional labour and contractor cost adjustments has left us disappointed and frustrated. Its continued willingness to elevate partial and anecdotal 'evidence' over well-researched and externally sourced evidence reflects poor regulatory practice. If Ofgem does not recognise our claim it will need to be prepared to fully justify its rationale.
- In both the areas of comparative benchmarking and labour/contractor adjustments, Ofgem has a considerable way to go if it is to produce outcomes for inclusion within the Initial Proposals document which could be acceptable to EDF Energy.
- If Ofgem wishes to re-categorise Atypical Costs into the relevant cost categories, it will need to ensure that the cost drivers selected can satisfactorily explain these costs. If Ofgem is unable to modify these costs drivers within the timescales of this Price Control, we believe that they should remain classified as Atypicals.

Methodology – core network investment

- We welcome the decision to review LPN Reinforcement on an individual project (rather than top-down) basis. Ofgem should note that exactly similar principles apply to the development of EPN and SPN major project proposals
- Bottom-up scheme based assessments will often reveal a rationale for investment that is invisible to top-down modelling. In particular, our approach is holistic – maximising cost-effective synergies. However, this can give rise to apparently higher cost solutions than a minimalist approach which will prove more costly in the longer term.
- We note our relatively 'low / very low' level of added capacity - forecast load growth. This is a reflection of our efficient management of asset utilisation.
- Subject to our comments on the role of bottom-up reviews above we broadly agree with the approach Ofgem has taken to modelling capex volumes.

- Further work is needed, however, in the area of unit costs. In particular, our relatively ‘very high’ unit costs need to properly take account of:
  - Regional costs
  - Inner London specific factors (LPN) (urbanicity)
  - Our holistic approach to network solutions (as discussed above)
- We were surprised by Ofgem’s ‘disappointment’ that we did not use discretionary ‘investment’ as an opportunity to develop specialist teams etc. (see Methodology paper paragraph 5.10). However, we are exploring the potential for DSM in the context of credible network outage scenarios.

Network investment

- Ofgem is right to review the effectiveness of the current innovation incentives. Whilst we have supported the RPZ scheme, with two registered RPZs during the period, we would support the introduction of a more effective alternative. The role of DNOs will need to evolve significantly if the government’s obligations and aspirations in respect of reduced carbon emissions are to be realised.
- We believe it is now essential that DNOs work in partnership with other industry stakeholders to develop and deploy the new network technologies and network management techniques that will be essential to support a future low carbon economy. It will be important that the nature and quantum of the new innovation incentive properly reflect the costs and risks that will fall on DNOs in pursuing these developments.

Ongoing efficiencies and input prices

- We believe it is inappropriate for Ofgem to assert future efficiency savings. The regulatory process should encourage the companies to reveal this information. This ensures that the benefits are shared between shareholders and customers.
- We are particularly concerned that Ofgem has historically asserted future frontier shift movements without funding such movements. This effectively means that the shareholders get no benefit and customers get all the benefit. This is inappropriate.
- If Ofgem does not fund such savings, an alternative approach would be to include only a proportion of the savings, leaving the residual as a “carrot” for the companies.
- The evidence from the setting of cost allowances at DR4 is that the overwhelming majority of DNOs have been unable to deliver Ofgem's predicted efficiencies and are seeing costs running ahead of allowances

- EDF Energy believes that NERAs methodology for forecasting real price inflation should be applied within DPCR5 as this is an objective and transparent method. It draws on reliable market evidence where available, and avoids the use of subjective assumptions in the long-run where reliable forecasts are not available.

Customers

- We welcome Ofgem's decision to base the worst-served customers allowance on the number of worst-served customers in each DNO.
- We believe that it is inappropriate for Ofgem to impose further quality of supply improvements without also giving the DNOs the requisite funding to achieve the required levels of performance. Such an approach is in effect a covert penalty mechanism.

Network output measures

- We broadly agree with the proposed methodology for output measures for general reinforcement and asset replacement, as shown in the May document and discussed with the Network Cost Working Group
- We look forward to working constructively with Ofgem to develop network output measures as part of the DPCR5 settlement.
- We also welcome Ofgem's intent to use Tier Two Output Measures and we look forward to developing outputs further over the DPCR5 period.
- We believe that we should create common measures where possible, but acknowledge that there will be issues specific to each DNO.
- Output Measures based on fault rates must acknowledge the volatility inherent in the measure

Cost incentives

- We strongly support Ofgem's proposal to equalise opex and capex incentives. The current differential incentives on opex and capex can distort DNO behaviours in a number of unhelpful ways:
    - Favouring capex solutions over maintenance (and increasing costs to consumers overall)
    - Discouraging demand side management actions (and increasing costs to consumers)
    - Favouring contracting solutions for capex that incorporate opex activities (undermining cost comparisons)
    - Encouraging the badging of opex /indirects as capex

- The RRP process has already demonstrated that at DPCR4 there were material differences in accounting policy across the DNOs and that significant resource is needed by Ofgem to investigate cost boundary areas.
- Equalisation of incentives also implies the use of symmetrical incentives on opex overspends which, when combined with the IQI mechanism, helps to mitigate the degree of error, discussed elsewhere in this response, inherent in Ofgem's opex benchmarking.
- The proposed application of the GDN IQI matrix to electricity distribution represents a significant increase in risk to the DNOs, due to the tightening of the allowed expenditure calculation.

Managing uncertainty

- We believe that the risks which DNOs are asked to bear in DPCR5 should not be materially different from those for DPCR4. This means that Ofgem should only introduce new risk management mechanisms where material new risks have arisen.
- Our current view is that additional protection will only be needed for:
  - Debt cost volatility
  - Tax legislation
  - Material costs volatility
  - General reinforcement
  - Connections
- On the question of whether there should be one general re-opener mechanism or a set of bespoke ones we believe that it is easier to target new risks only with bespoke mechanisms.

Tax methodology

- There are a limited number of areas now where EDF Energy and Ofgem need to do more work to reach an agreed position.
- We are pleased that Ofgem have commended EDF Energy on the quality of their submission.
- Ofgem is still unwilling to include changes in case law/HMRC interpretation as part of the trigger mechanism. This leaves significant risk with EDF Energy.
- Ofgem is determined to use a 'common' approach for capital allowance additions. This should benefit EDF Energy.

Section 2: Detailed response

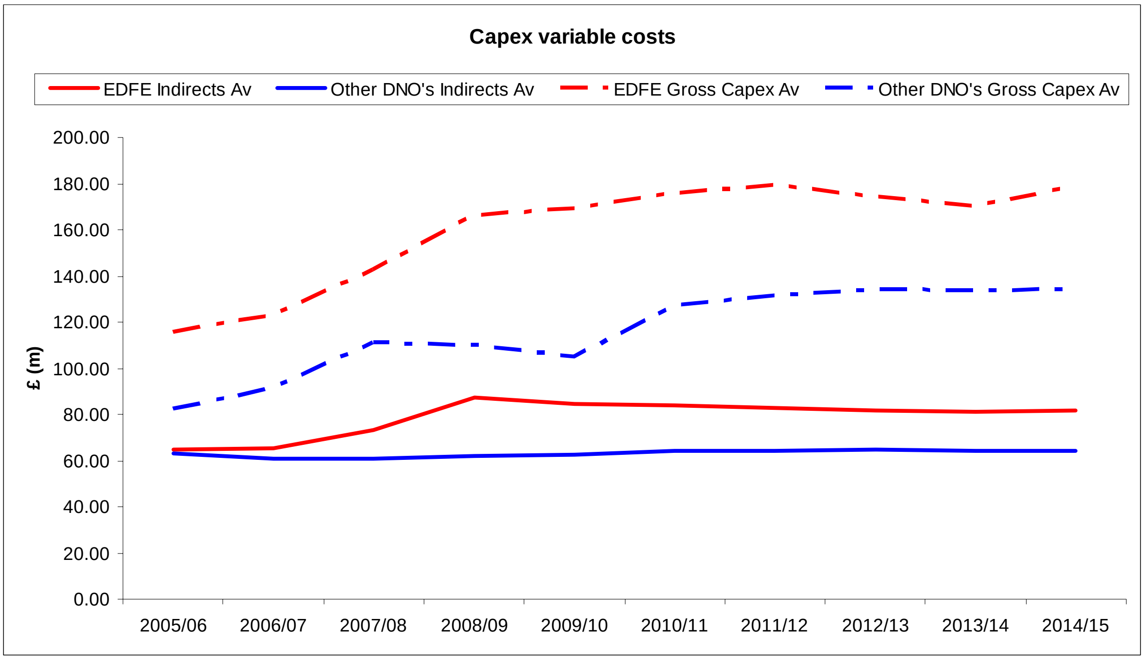
2. Overview of FBPQ forecasts

Question 1: What are your views on the DNO cost forecasts presented in this chapter?

An important aspect of the DNO's forecasts that we do not understand concerns the resources needed to support enlarged capex programmes.

EDF Energy was the first of the DNOs to significantly increase the size of its capex programme and have experience of mobilising the necessary support resources. Indeed, as Ofgem is aware, we have employed the best practice, and highly transparent, NEC3 Professional Services Contracts (our Integrated Delivery Contracts) to underpin the mobilisation of those resources.

We are therefore puzzled to note that, although the DNOs are typically proposing substantial increases in their capex programmes, on average there is no material increase in indirect support costs. The chart below summarises the position.



Since the indirect costs concerned cover designers, stores, training, IT and data links, project managers and clerical support activities, it is difficult to see how DNOs can increase their capex programmes without incurring additional costs in these areas. On that basis, we can only conclude that either the costs have been erroneously left out of forecasts, or that they are within direct contractor capex costs.

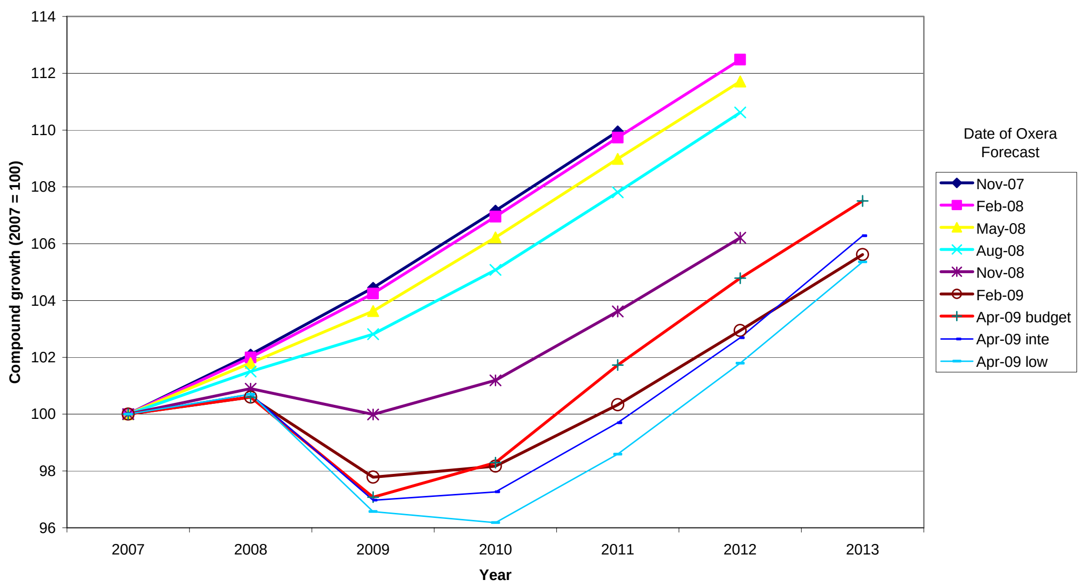
We are disappointed that Ofgem has to date not taken forward the survey which we proposed, requiring DNOs to estimate the proportions of Indirect Costs which are being delivered through closed-book contracts.

Clearly, Ofgem was right to make an adjustment in its opex benchmarking for our IDT costs (open –book contracts).

Making accurate forecasts of the level of required load-related expenditure is very difficult in the current economic climate. However, it is important that DNO's have a robust estimate of the baseline load related expenditure. We note with some surprise that only CE, ENW, EDF Energy and Scottish Power have reduced their gross load related expenditure from the Draft FBPQ (August 2008) (table 2.1) and only EDF Energy has made a reduction in its overall Network investment.

Although we recognise that their may be other drivers for a rising estimate of gross load related expenditure we are surprised that this is the case against the backdrop of the deterioration in the economic climate.

Evolution of forecasts for GDP growth over time



Furthermore, we would expect DNOs to have further adjusted their June FBPQ update to reflect the change in the consensus view of the economic climate (as per the graph above).

3. Operational cost assessment methodology and results

Question 1: Have we exposed the correct costs to comparative benchmarking?

Question 2: Do you agree with the assumptions we have made for our core analysis?

Question 3: What are the appropriate cost drivers for each of the cost groupings?

Question 4: How should we determine baselines for the costs excluded from comparative benchmarking?

Question 6: What weight should we give to the benchmarking relative to other considerations?

We have addressed Ofgem's question 1 through 4 and question 6 below. We then address question 5 separately.

Introduction

EDF Energy welcomes Ofgem's efforts to develop a more sophisticated approach to comparative benchmarking, which takes advantage of the 3 years of Regulatory Reporting Pack (RRP) data collected during DPCR4.

Whilst we acknowledge the significant step-forward that this represents, it also places much greater demands in respect of:

- Ensuring that cost data is robust and has been reported on the same basis
- Making adjustments and exclusions which reflect the legitimate differences between the environments within which the DNOs operate
- Identifying cost drivers which genuinely explain the activity observed
- Selecting and applying appropriate statistical methods, such that the outcomes have the confidence of the DNOs and other stakeholders.

Within the work-to-date, presented in the May policy paper, there are a number of issues which we will highlight in this response. It is our belief that these need to be addressed before the comparative benchmarking can be concluded. As such we have structured this response in line with the following headings:

- Cost Categories and Cost Groupings (including Cost Drivers)
- Adjustments and Exclusions
- Statistical Methods
- Setting of Allowances

- General Comments

Cost Categories and Cost Groupings

EDF Energy welcomes a number of the decisions that Ofgem has made in respect of those direct and indirect costs which have been excluded from the regression analysis, as shown on fig 3.1 of the May paper.

We would propose that allowances be set in these areas on the basis of historical spend. Where a DNO is proposing expenditure at variance to past levels, Ofgem should require the DNO to provide detailed justification.

We would wish to make observations about the following Cost Categories and Groupings and their associated drivers:

1. <u>LV and HV Underground Faults</u>

We endorse the inclusion of costs relating to NLRE LV and HV underground cables within this cost category, and the exclusion of high value, low frequency faults.

We accept the choice of fault volumes as cost driver. However, for this to have legitimacy, Ofgem needs to ensure that there is consistency of driver composition, particularly in respect of non-damage faults.

We would recommend that all non-damage faults should be accounted for within the regressions of either LV and HV Underground or Overhead cables. If the data is not readily available, the DNOs should be asked to identify the split of non-damage faults between these two cost categories.

We are also concerned that HV, LV mains and services and non-damage faults are given the same weighting in the regression, even though the cost implications of these classes of faults are very different. In our experience, HV cable faults are typically twice as expensive as LV mains faults, and around 12 times as expensive as non-damage faults. This should be reflected in the construction of the driver.

2. <u>Non Quality of Supply Faults</u>

There are significant issues which will need to be resolved with the non Quality of Supply faults cost category before Ofgem can contemplate including this within the regression analysis.

Earlier in the year, Ofgem indicated that it had major concerns over the very large variations of costs being reported by the DNOs – we are disappointed to note that this does not appear to have been resolved.

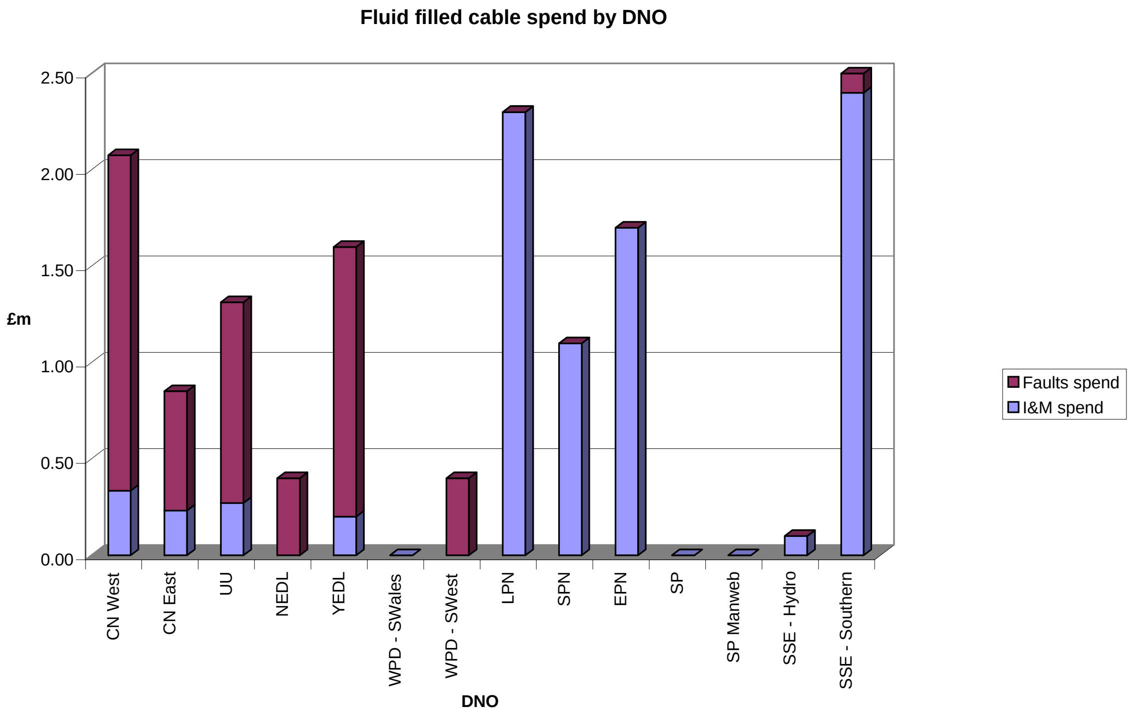
Further to this, Ofgem has proposed ‘number of customers’ as cost driver. Whilst this might be a reasonable choice for those costs relating to cut-out changes, it is our experience that these costs are substantially outweighed by those relating to streetlighting faults. As such, we would propose that a composite driver needs to be developed with number of streetlights as the dominant contributor.

Ofgem needs to address the issues raised by the underlying cost data, and develop a more satisfactory cost driver before EDF Energy could accept this cost category being included within the regression analysis.

3. <u>Inspections and Maintenance</u>

EDF Energy has two major issues with the benchmarking of Inspections and Maintenance.

Firstly, our analysis suggests that the DNOs are still treating fluid-filled cable (FFC) costs differently, with EDF Energy and SSE recording the majority of costs in I&M, and the remaining DNOs attributing most of the costs to Faults – see barchart below. Companies who attribute the costs to Faults could effectively be allowed the expenditure twice: through a high value, low volume fault allowance, and through their apparent elevated efficiency in I&M.



When one considers that FFC costs accounted for 24% of LPN I&M costs in 2007/08, then the correct treatment of FFC expenditure is material. As such, Ofgem should either reallocate all FFC costs to I&M, or alternatively all FFC costs should be taken out of I&M and assessed under the high value, low volume fault approach. We believe that the latter is the most appropriate option.

Secondly, we are concerned about the choice of Asset Hours Work driver as the cost driver for I&M. The May paper does not define how this driver has been derived, and this information should be circulated.

Fundamentally, we believe that this driver is likely to be too subjective and that wherever possible Ofgem should be seeking out drivers that can be objectively calculated.

4. Tree Cutting

Ofgem proposes the use of 'number of spans cut' as the cost driver for this activity. We believe that there are two flaws in this.

Firstly, there is more to this activity than simply cutting trees. This cost category would be better entitled Tree Management, reflecting the ongoing inspection, planning and management processes. Both RRP and FBPQ reflect this through the collection of data on 'spans affected by trees', in addition to 'spans cut'.

Secondly, it is the length of line that is cut or managed which describes this activity. The 'spans cut' driver proposed would be a good proxy for this, if spans were a uniform length across the DNOs. However, analysis of RRP returns shows a huge variation.

Therefore, EDF Energy recommends that the appropriate cost driver for this is 'length of line affected by trees' calculated for each DNO by multiplying their number of spans affected at each voltage level by their average span length.

As a more general point, we note the wide variation in apparent 'unit costs' that the DNOs show for these activities. This suggests to us that there are factors, other than DNO efficiency, impacting on these costs. We also note the information requested in respect of high and low density tree coverage in the FBPQ.

In discussion with Ofgem, we were disappointed to hear doubts being expressed about the quality of tree data provided by the DNO community. Ofgem is aware that EDF Energy commissioned Infoterra to survey our overhead network, and the output of this has been shared with Ofgem. Hence, it is frustrating to find Ofgem being forced to adopt the "lowest common denominator" in respect of data quality, thus undermining the process of comparative benchmarking.

We proposed the introduction of some form of differentiated treatment in this area, potentially allowing costs presented by those DNOs that had made available the right quality of robust data to be included in the settlement and to calculate the allowances for other DNOs by reference to a benchmarked amount based on this sub group of DNOs. Such an approach would send a clear signal to other DNOs, ahead of the next price control, that they too would benefit from undertaking an objective assessment of the proportions of their networks impacted by trees.

We explained that for our DNOs we had used the data we had collected on tree density as part of our recent contract letting process thereby ensuring we have an efficient level of market tested costs for all of our tree cutting activities.

We would expect Ofgem to take account of these factors when setting allowances for this cost category.

5. Group 3 (Business Support Costs)

In the past, we have expressed concern over the potential for 'boundary issues' between these cost categories, and hence we welcome the bringing together of HR and non-operational training, Finance and Regulation and CEO/Group Management in a single grouping.

We also recognise that it makes sense to assess efficiency at a DNO Group level, as it is likely that there will be some economies of scale. However it should be noted that some aspects of HR, for example, will need to remain distributed, and that this will have a cost implication for DNO Groups, such as EDF Energy, covering large geographies.

Our major concern with Ofgem's proposals in this area centres on the cost driver. HR/non-operational training, Finance & Regulation and CEO/Group Management together comprise over 90% of the costs. Logically, any chosen cost driver must be relevant to these activities and must reflect all activities in the organisation which drawn upon those services. We would argue that this indicates a composite which takes account of the scale of the organisation in terms of both people and business activity.

There is no logic to support the choice of Network MEAV, and having experimented with a few alternatives (including DPCR3 and DPCR4 CSVs, Network Investment + Network Operating Costs, Total Number of FTEs, Total Number of Customers), Network MEAV also gives the worst statistical fit.

We will endeavour to make proposals on a suitable cost driver in advance of the Initial Proposals, but at this stage it is important for Ofgem to accept that Network MEAV is not a credible choice.

As a final point, we welcome Ofgem's decision to request information on DPCR4 workforce renewal costs as part of the June FBPQ. We would expect Ofgem to factor such costs into the benchmarking analysis, so that those companies who have been first to recognise and respond to this crucial issue are not disadvantaged.

Adjustments and Exclusions

EDF Energy supports Ofgem's proposal to include related-party margins and exclude pensions, and whilst it is our belief that severe weather atypical events should be excluded, we do not feel this is a major issue.

With respect to pension costs, if Ofgem can define a robust normalisation method then this would provide a better long-term solution.

Regional Labour and Contractor adjustments:

EDF Energy has made a number of submissions to Ofgem in respect of the increased cost of operation in the LPN, SPN and EPN areas. This information has been prepared independently, draws heavily on external sources and in our view provides a well-argued and compelling case.

Furthermore our own research demonstrates that the existence of regional labour costs is very much the norm, in every industry or market. Salary surveys are available, from many of the leading recruitment and HT consultancies, covering many disciplines, and all of them, as a matter of course, provide a regional breakdown.

Central Government and other regulators, such as OFWAT, routinely adjust for regional costs. Furthermore, they typically use ASHE and BCIS data as the foundation for this analysis. Hence, we are not only puzzled as to why Ofgem appears happy to be out-of-step, but also frustrated that it is unable to provide coherent arguments to justify this position.

A further concern is that Ofgem seems content to equate the detailed evidence provided by EDF Energy, with mere anecdotal material provided by some other DNOs and Unite. We have indicated the factual inaccuracies that exist within the Unite document, and have so far not received any response to this.

It should be emphasised that even if it were the case that there is a continuing residue of national pay scales (which we do not accept), this would not apply either to contractors' costs or to the 2,500 new people that we must find by 2015.

In summary, it is our belief that the case for a full regional labour and contractor adjustment is inarguable. As is good regulatory practice, Ofgem is under an obligation to adopt an evidence-based approach to this issue, and needs to apply appropriate weighting to the arguments presented. If Ofgem comes to a different conclusion, it will need to be prepared to justify this decision.

Urbanicity

At the Cost Review bilateral we were able to present additional analysis, at the request of Ofgem, which demonstrates the implications of operating in an urban and super-urban environment.

Arguably, there are two classes of adjustment which have emerged from our discussions: the unique LPN factors, including cable tunnel maintenance, local authority subway leases, congestion charge and Pool Re terrorism insurance; and the urban factors which a number of DNOs might experience including increased complexity of groundworks, additional engineering costs associated with underground substations, additional out-of-hours working because of traffic sensitivity/access restrictions etc, and maintenance of forced ventilation.

We have presented Ofgem with our view of the magnitude of adjustments that are appropriate, and would be happy to discuss this further, if necessary.

IDTs (open-book contracts)

We were pleased that the May paper acknowledged the need for appropriate treatment of costs stemming from open-book contracts. We would argue that this is not really an adjustment at all, but merely a normalisation exercise to ensure that there is a like-for-like comparison in respect of Indirect Costs.

We firmly believe that Ofgem should be encouraging greater transparency in respect of the make-up of capital expenditure, and it would surely be perverse if companies had a disincentive to do this as a result of unfavourable accounting treatments.

Sparsity and Interconnection

We have no issue with the principle of adjustments in this area, as long as the DNOs concerned can provide robust justifications for them and for the level of adjustments being claimed.

Statistical Methods

EDF Energy welcomes Ofgem's efforts to develop a more sophisticated approach to comparative benchmarking, making use of the RRP data gathered during DPCR4. It has also been very helpful for Ofgem to share data from this model, so that it can be validated and tested by the DNOs.

As Ofgem are aware, we have appointed an academic advisor to assist us in evaluating the underlying methodology and the manner in which this has been implemented. He has raised a number of concerns that are documented below:

- The model has very limited documentation and thus it is not easy to understand how it works, and hence be able to judge the statistical methods employed
- Estimation: There is no discussion of the rationale underpinning Ofgem' s choice of statistical methodology. Were random effects estimators considered and rejected?
- Statistical Reporting: Without reporting of estimated coefficients and standard errors, it is not possible to assess the plausibility, reliability or accuracy of the proposed relationships
- Statistical Testing: Qualitative reporting of test results is provided, but no numerical values are reported. No statements are made as to the level of statistical significance of the test results.
- Accuracy: No standard errors or confidence levels are provided for any of the results thus making it impossible to judge whether they have statistical worth. This would apply equally to any cost frontier that is

defined. Estimated frontiers based on quartiles from the median are likely to be inaccurate, for a small sample size, such as this one.

- Top-down Cost Driver: There are significant doubts about the statistical validity of the proposed top down cost driver. This should take the form of a linear aggregation of the underlying drivers, rather than the "weighted geometric mean" proposed. The requirement to insert dummy values for LPN is a consequence of the inappropriate construction of this driver.
- There is clear evidence of cost drivers not being independent of the costs

For the questions relating to reporting, testing and accuracy, this information is presumably available, and simply needs to be published by Ofgem.

Given the scale of the issues that we have identified, in respect of both the methodology and the detailed benchmarking, we are concerned that Ofgem do not have sufficient time or resources to address them. In particular, we do not see how Ofgem will be in a position to make firm statements on comparative efficiency, or set allowances based upon an upper quartile frontier, in time for inclusion within the Initial Proposals.

International Comparison

We find Ofgem's decision to compare UK DNOs with US networks, rather than European companies, somewhat curious, and are sceptical about the justification of similar climate.

Ofgem needs to be careful in making any broad-brush comparisons which suggest that the companies in one country are more efficient than in another. There are significant structural differences between the UK and US electricity industries which make a comparison very problematic. These include:

- The much higher proportion of overhead line on typical US networks than in the UK.
- The lower levels of historic investment in US assets, resulting in apparently lower unit costs
- The lack of security standards, such as N-2 in the US, resulting in lower levels of network investment
- US distribution systems typically are made up of a greater proportion of lower voltage assets, thus avoiding much of the expense in the UK on EHV assets/operations
- The much greater use of ducting for underground cables in the US
- US connection charges typically fund 100% of reinforcement, thus reducing requirements for network-funded load-related investment
- Many of the rural networks are owned by municipalities or co-operatives, and in many cases are not required to report their costs to the regulator (FERC). These are likely to be the higher cost networks.

In contrast to the above, EDF Energy has participated in independently-organised, international benchmarking studies for a number of years. The outcomes of these have been to demonstrate consistently that UK DNOs as an industry are amongst the most efficient in Europe.

Question 5: How should we treat atypical costs in the price control settlement?

If Ofgem wishes to re-categorise Atypical Costs into the relevant cost categories, it will need to ensure that the cost drivers selected can satisfactorily explain these costs. If Ofgem is unable to modify these cost drivers within the timescales of this Price Control, we believe that they should remain classified as Atypicals.

4. Methodology – Core Network Investment

Question 1: Do you agree with Ofgem's approach to assessing core network investment allowances based on the wide range of evidence detailed in the chapter?

We welcome the decision to review LPN Reinforcement on an individual project (rather than top-down) basis. In particular, PB Power's work was professionally conducted and provides a well-documented appraisal of our work.

Ofgem should note that exactly similar principles apply to the development of EPN and SPN major project proposals.

Bottom-up scheme based assessments will often reveal a rationale for investment which is invisible to top-down modelling. In particular, our approach is holistic – maximising cost-effective synergies. However, this can give rise to apparently higher cost solutions than a minimalist approach which will prove more costly in the longer term. LPN West End RDP is a good example (examined by PB Power), where the preferred solution was considered "reasonable and justified based on load and asset replacement drivers" although all three rejected options were lower cost.

We note our relatively 'low / very low' level of added capacity - forecast load growth. This is a reflection of our efficient management of asset utilisation.

We also welcome the interactive approach adopted by Ofgem's Network Investment team; the supplementary question process and bilateral discussion have been helpful in resolving issues and clarifying understanding. We are confident that the additional supporting evidence we have provided through this process should enable Ofgem to give favourable consideration to our investment proposals, including those areas where their modelling might have suggested a lower or less costly investment requirement.

The continuous investment planning cycle process may be disrupted by being parcelled into regulatory periods. We have some concern that the focus on the five year period may result in proposed schemes which are scheduled towards the end of period being inappropriately scrutinised for potential deferral based on forecast growth, degradation, outcome of wayleave negotiations etc. The Net Present Value of deferring a scheme by a year is a relatively minor benefit when considered against the potential downside of front-loading the subsequent regulatory period with urgent investment.

Question 2: Do you agree with the primary network general reinforcement modelling methodology that Ofgem has adopted for DPCR5?

The modelling methodology is no doubt helpful in terms of comparing DNOs' proposals and in terms of providing a sense-check of an individual DNO's relative risk management strategy (e.g. in terms of capacity added relative to forecast demand growth). However, in terms of cost of capacity added we remain concerned (see also our comments under Question 1) that the top down modelling may overlook legitimate expenditure necessary to provide a holistic reinforcement solution.

Question 3: Do you agree with the asset replacement modelling methodology that Ofgem has adopted for DPCR5?

Subject to our comments on the role of bottom-up reviews above, we broadly agree with the approach Ofgem has taken to modelling capex volumes. However, given that the asset replacement modelling methodology is essentially age profile-based, the interactive communication (supplementary questions and bilateral discussion) is an essential complement to the top down methodology, since age is not in itself an investment driver. In particular, there might be sound reasons for a DNO apparently assuming a lower life expectancy for certain asset groups because of concerns over condition, reliability, defects, etc.

Unit costs

Further work is needed, however, in the area of unit costs. In particular, our relatively 'very high' unit costs need to properly take account of:

- regional / inner M25 / M11/M3/M4 corridor
- inner London specific factors (LPN) (urbanicity)
- our holistic approach to network solutions (as discussed above)

We have provided further evidence that 'urbanicity' is a real cost driver both for operating costs and capital investment, for example because of the restrictions it places on road openings, access to substations, and normal-hours working.

We received the PB Power unit cost information on29 May and included analysis of industry replacement costs. Unit costs can be justifiably different for a number of reasons which give rise to significant variations:

- For cable installation – surface/ground type, single/multiple circuit;
- For switchgear – type of enclosure, installation of RTU and remote control, holistic solutions (for example taking the opportunity to consolidate substation assets by adopting 'unit substation' solutions where the local transformer, LV board, buildings exhibit evidence of significant condition degradation);

- For major transformers – ratings, sound enclosures, provision of full oil containment;
- For overhead lines – use of ABC for LV lines (to deal effectively with ESQCR obligations in respect of clearances and resilience in a region where a tree management solution alone is simply impractical due to the scale of the tree proximity problem).
- General – inclusion/exclusion of cable terminations, on-site generation etc. (Note: we do not believe it is acceptable not to provide temporary generation where it is reasonably practical to do so; even though the costs of so doing are significantly in excess of the revenue benefits arising from IIS). This is not an issue informed by 'WTP' since customers who provide evidence under such surveys almost certainly presume that the context of the question is supply failures due to faults rather than deliberate disconnections for maintenance.

Capex volumes

Comparison of DR4 / DR5 11kV/LV reinforcement investment – our higher DPCR5 values are at least partly a reflection of:

- use of 11kV interconnection schemes where this is a cost-effective alternative to ITC; and
- (for LPN) the inclusion of investment to address the central London LV interconnected HV network

Regarding our generally low/very low asset replacement forecasts:

- We have explained most of the apparent exceptions through our responses to follow-up questions (e.g. switchgear)
- Our confidence in our relatively low (cf. other DNOs) forecast arises from our improved visibility of asset condition information
- This has also enabled us to contain NLRE during DR4

We will be providing additional compelling evidence of need for investment in a number of areas where Ofgem's modelling suggests a lower volume. Our expectation in such cases is that our bottom-up derived evidence will take precedence over Ofgem's top down modelling.

Discretionary expenditure

We were surprised by Ofgem's 'disappointment' that we did not use discretionary 'investment' as an opportunity to develop specialist teams etc (see Methodology paper paragraph 5.10). However we are exploring the potential for DSM in the context of credible network outage scenarios. KEMA has been commissioned to explore realistic potential, in terms of:

- scope for P2/6 related network reinforcement deferral
- likely required level of financial incentive
- administrative costs

We do, however, welcome Ofgem's further consideration of potential innovation incentives as we believe this to be an area where discretionary investment will prove beneficial in bringing forward the development and deployment of new technologies and new approaches to network management (see our response to question 5 below).

Question 4: Is the outlined process for developing Initial Proposals suitable?

Subject to our comments above, yes.

5. Network Investment – Environment

Question 1: Do you agree with our approach to assessing the forecasts of distributed generation, discretionary expenditure and losses and are there any other factors you think we need to take into consideration?

Distributed Generation

Forecasts of distributed generation penetration are made against a very uncertain background of information which is reflected in the confidence levels we have applied to our forecasts. On the one hand we feel it would be inappropriate not to reflect government expectations in respect of renewable energy / low carbon local generation solutions (shortly to be supported by feed-in tariffs) but on the other hand we have yet to see hard evidence of the scale of growth in distributed generation implied by government targets. Our forecasts are based on a combination of known schemes and top down 'low carbon economy' based projections.

Discretionary expenditure for future network flexibility

Ofgem is right to review the effectiveness of the current innovation incentives and, in particular, consider a more effective alternative to the RPZ scheme, albeit that we have supported that scheme with two registered RPZs during the period.

The role of DNOs will need to evolve significantly if the government's obligations and aspirations in respect of reduced carbon emissions are to be realised. We believe it is now essential that DNOs work in partnership with other industry stakeholders to develop and deploy the new network technologies and network management techniques that will be essential to support a future low carbon economy. It will be important that the nature and quantum of the new innovation incentive properly reflects the costs and risks that will fall on DNOs in pursuing these developments.

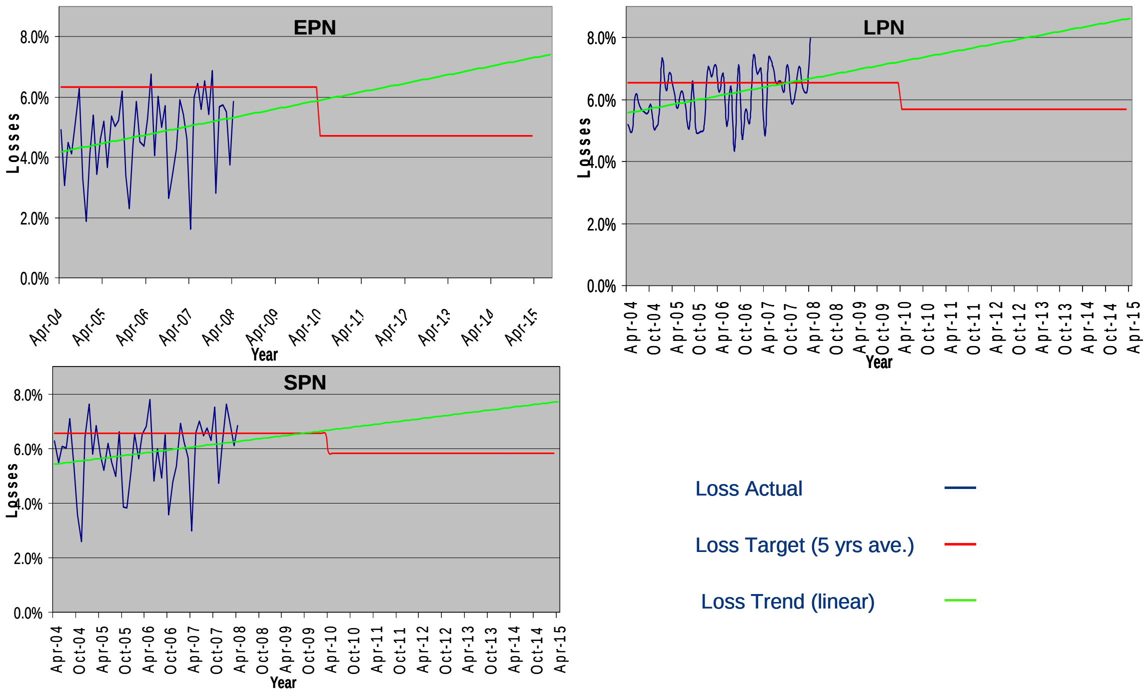
Losses

Setting losses targets

Our principal concern in this area is that in setting targets Ofgem should recognise the limited ability of DNOs to change the underlying trend of losses measured using settlement data.

The charts below show that in recent years the underlying trend in losses has been rising on all three of our networks. The charts also show that the impact of our industry-leading data management activities have made negligible impact on the underlying direction of travel.

Clearly, if Ofgem uses a simple average of past performance, there would be a high risk of setting unachievable targets. The charts below illustrate this. They show the current DPCR4 targets, an illustrative DPCR5 target based on a five year average and a regression line which extrapolates the current trends.



EDF Energy is the leading company in the area of data quality management and as such we would expect to outperform regulatory targets. Instead, by ignoring the underlying trends, or through asserting incorrectly that DNOs can control them, Ofgem risks setting targets which would create significant and unavoidable financial penalties.

Ofgem's general policy is to set incentives such that an efficient company can outperform the regulatory cost of capital. That principle applies equally to all incentives including losses.

Ofgem also needs to take care when interpreting the information contained in Table 5.5. In our case we have interpreted Ofgem's requirement as forecasting the marginal impact on underlying losses trends of our proposed capex programmes. This means that our capex programme is expected to only reduce losses compared to the underlying trend by a very small amount:

LPN 0.03%

SPN 0.06%

EPN 0.04%

This is a consequence of the fact that cost-effective (and indeed carbon-cost effective) loss reducing interventions are generally possible only where there are other drivers for investment, and where a lower loss option is available. Whereas over 70% of technical losses are incurred on HV and LV circuits, and HV/LV transformers, these are generally not the asset groups currently giving rise to capacity headroom or significant health / safety concerns (albeit an exception is LV overhead lines where we will take the opportunity to improve phase balancing during re-conductoring works). Hence relatively little of our general reinforcement and asset replacement investment addresses these asset groups. Ofgem has published a non-technical overview of DNO losses written by Sohn Associates. This is a useful document which sets out the potential impact of the settlements system on distribution losses. The main factors Sohn identify include:

- Theft
- Idle service energisation status
- Profile error/incorrect assignment to profile
- Timeswitch error
- Lack of meter readings
- Meter accuracy
- Unmetered supply inventories

Of this list, the DNOs are only directly responsible for the last one, unmetered supply inventories, and even there they require the co-operation of lighting authorities to identify changes to the inventory.

Use of unadjusted settlements data

We understand why Ofgem is considering restricting the losses incentive to unadjusted settlements data as this provides a simpler audit trail. However, in doing so, Ofgem is taking away the incentive for DNOs to identify lost units which are older than the settlements window or will not ever be processed through settlements (e.g. illegal connections without mpans and suppliers).

Suppliers can be reluctant to enter into settlements any data where there is little prospect of a customer paying for the units found. This means that a DNO would only be rewarded for a proportion (we believe around half) of units found.

Taking these two points together, Ofgem risks destroying the incentive on DNOs to carry out data management activities, including the field work carried out by revenue protection officers. EDF Energy current employs around 100 people on these activities, but should Ofgem proceed with the changes they have indicated the business case for maintaining resource at these levels is likely to fall away.

Way forward

Ofgem should do two things

1. Retain the existing losses incentive to encourage DNOs to reduce non-technical losses, but with a reduced incentive rate (recognising the smaller environmental benefits available for non-technical losses) and with targets that reflect current trends.
2. Incentivise technical loss reduction through a simple inputs based scheme.

6. Ongoing efficiencies and input prices

Ongoing efficiency improvements

Question 1: Have we identified the most relevant unit cost and productivity measures from other sectors to help inform our ongoing efficiency assumption for DPCR5?

Question 2: When calculating these measures, which comparator sectors and time periods should we focus on?

Question 3: What weight should we give to this analysis relative to other information?

We believe it is inappropriate for Ofgem to assert future efficiency savings. The regulatory process should encourage the companies to reveal this information. This ensures that the benefits are shared between shareholders and customers.

We are particularly concerned that Ofgem has historically asserted future frontier shift movements without funding such movements. This effectively means that the shareholders get no benefit and customers get all the benefit. This is inappropriate. If Ofgem does not fund such savings, an alternative approach would be to only include a proportion of the savings, leaving the residual as a "carrot" for the companies.

As Ofgem has recognised, the choice of comparator industries and assessment time period can have a significant effect on the output of any total factor productivity analysis. With respect to comparator industries, we fail to see why the manufacture of chemicals has any relevance to the operation and construction of electricity networks. We are also concerned that the inclusion of the manufacture of electrical and optical equipment sector may create a double count. This is because the productivity improvements that manufacturers of, say, transformers and switchgear are able to deliver are already reflected in the price that DNOs pay for their materials.

It may also be beneficial to include the broader finance, insurance, real estate and business services EU KLEMS sector rather than financial intermediation. The former contains more information about the efficiency savings generated by providers of services such as HR, accounting, IT and insurance, all of which are directly relevant to DNO indirect costs.

With respect to time period we would suggest that the period 1990-2005 is also used. We have concerns that using the 1970-2005 period is less relevant to future costs. It is unclear why data from the 1970s and 1980s will provide relevant information on the scale of future efficiency in the period 2010-15. We believe the period 1990-2005 strikes the right balance between using the most up to date information but also provides a long enough time series for the data to be stable.

We agree that it is sensible for Ofgem to consider both gross output and value added TFP metrics. As Ofgem has recognised both of these measures have weaknesses, further assessment as to which is the most appropriate would be sensible.

Review of evidence on real price effects

Question 4: What method should we use for setting our input price assumptions for DPCR5?

Within our Financial Business Plan Questionnaire submissions in August 2008 and February 2009 we included a forecast of the impact of RPE in DPCR5. This was based upon a methodology developed by the consultants NERA.
The first stage in constructing the RPE forecasts was to select indices which reflect trends in EDF Energy's costs for materials, internal labour and contract labour. The RPE forecasts were then based on the following methodology:

- In the short-term (2-5 years), market evidence was used, such as forecasts of the relevant price indices from reputable organisations and forward commodity prices; and
- In the longer-term, forecasts assumed reversion to long-run average growth rates (in real terms).

Where long-run average growth rates were calculated, the longest time series of available data was used. In the February FBPQ the forecast impact of RPE in DPCR5 for EDF Energy was 1.5% p.a.

We still believe that this is an objective and transparent method for forecasting real price inflation and should be applied within DPCR5. It draws on reliable market evidence where available, and avoids the use of subjective assumptions in the long-run where reliable forecasts are not available. Statistical analysis was conducted that illustrated the sensitivity of the forecasts to the volume of infrastructure and utility capital expenditure. However, these analyses did not feed into the final recommendations, but rather acted as a cross-check on other third-party forecasts.

Ofgem commissioned CEPA to provide advice on input price inflation, factors affecting electricity demand and the potential need for a mechanism to address uncertainty associated with input price inflation. Their main criticism of EDF Energy's/NERA's study was that it did not consider scenarios regarding future macroeconomic conditions, which CEPA believes to be an important factor in the current period of macroeconomic uncertainty.

At the time of preparing forecasts, it was noted that they were subject to considerable uncertainty due to factors such as the impact of large infrastructure projects on labour markets, commodity prices, and the impact of worsening macroeconomic conditions. It is likely that these forecasts may now be out-of-date and no longer reflective of available market evidence. However, scenarios were not prepared around our forecasts for several reasons:

- First, defining scenarios for variables such as commodity prices would have required either complex macro-economic modelling or subjective judgments about the interactions between specific input price indices and conditions in labour markets, macroeconomic trends, and commodity markets etc.
- Second, even once we understood the interactions between RPEs and macro-economic variables, any scenario would have required assumptions about the values of these variables in the future, e.g. copper and aluminium prices, GDP growth, exchange rates, etc. Any scenario based on a set of macro-economic assumptions would probably – in the current climate – have become outdated just as quickly as the assumptions underlying our recommended RPEs.
- Finally, a range of scenarios regarding future input price inflation is of no use for regulatory purposes, if the aim is to set a fixed regulatory revenue allowance. Ofgem would inevitably have to make a subjective judgement as to which single forecast (or which average over different scenarios) is the appropriate basis for this allowance. There is no clear way to make this judgement robustly amid changing conditions, as CEPA itself recognises:

"*The range of scenarios also provides a degree of flexibility for Ofgem as to how it uses our conclusions in reaching conclusions for the price review. While one, or some weighted combination of the scenarios may appear to be the most robust at this stage **developments between now and the final proposals towards the end of 2009 may suggest that a different scenario is more appropriate.***"

We still believe that rather than relying on subjective judgments about future conditions in the macro-economy and in specific labour and product markets, a more objective approach to RPEs would be to prepare a single forecast using the most up-to-date information available at the time of the DPCR5 determination. If there is a wide range of uncertainty around this forecast, Ofgem should expect a need to adjust (i.e. to index) the fixed revenue allowance accordingly.

CEPA RPE Forecasts

We do not believe that CEPA's forecasts are robust, as they are based on an assumed relationship between selected input price indices and RPI inflation. CEPA has not presented any evidence of the apparent link between input price inflation and retail price inflation of the form used in CEPA's analysis. The level of input price inflation may influence the level of RPI inflation and vice versa. However, the *differences* between input price inflation and RPI inflation (i.e. the RPEs) also depend on many other factors, such as supply-demand conditions in the relevant input market, international commodity prices, or exchange rates.

A simple regression of a price index on RPI cannot capture these changing conditions, only the general relationship. Indeed, it is unlikely that any regression equation could robustly and objectively reflect the factors driving input price indices. The strength of correlation between a specific index and RPI is a poor criterion for selecting it to forecast real price inflation. The objective of setting RPEs within DNOs' price controls is to estimate the extent to which input prices will rise above the rate of general inflation. Whether input prices are correlated with RPI is irrelevant.

By using a simple regression of input price indices on RPI, CEPA's approach also ignores available market evidence on the potential for input prices to diverge from RPI. For instance, a forecast of electrical materials prices based on an historic relationship with RPI ignores available information on forward commodity prices (e.g. copper) that may significantly influence the future direction of DNOs' input costs.

Nominal wage deflation

Between April 2008 and April 2009, RPI fell by 1.2%. EDF Energy's forecast RPE for internal labour implies a margin of 1.4% over RPI, i.e. nominal growth in wage rates of only about 0.2% per annum. That is still consistent with nominal wages being "sticky downwards" (and implies a wage freeze at the moment, which has been reported for many sectors). If RPI fell much faster in future, it might be necessary to review our assumptions that nominal wages would fall as well, but at the moment such an outcome does not seem likely. In any case, short-term fluctuations in the economy are unlikely to affect real wage movements in the long-term.

As for CEPA's "medium term", the report merely contains speculation that the growth of real wage rates might possibly be different, or lower than in the past, because of economic conditions. However, CEPA does not provide any evidence that such an outcome is likely. Overall, CEPA's comments merely note that the future is uncertain, but do not state how uncertain the future is.

Potential savings from using contract labour

CEPA states that: "*Given the stickiness in nominal wages for internal staff, the bigger issue for this price control review for Ofgem may be the balance between internal and contractor labour that is assumed when setting the price control. To the extent that companies have greater scope to benefit from downward pressure on wages through more use of contractor labour then Ofgem might want to factor that into its price control proposals.*"

In DPCR4 EDF Energy has experienced a different pattern of recruitment from the one suggested by CEPA. Rising use of contractor labour in recent years has reflected difficulty in recruiting internal staff at current wage rates. Falling demand on contractor labour would make it easier to recruit permanent employees. It may not be cheaper to use consultants – CEPA has not substantiated its suggestion that DNOs might save money now switching from internal labour to contract labour, because CEPA's forecasts are not directly based on labour market evidence and forecasts. Ofgem should note that the choice between internal and contractor labour depends on a number of factors, including:

- The absolute level of in-house vs. contractor rates (not just the rates of change);
- The costs associated with recruitment and employment of internal labour vs. the costs of procurement and managing contractors; and
- The quality of service provided by contractors with regard to flexibility and quality of work.

Therefore the relative mix of internal and contractor labour is better determined in relation to a long term business strategy considering all factors. After internal review EDF Energy has already confirmed to Ofgem that it is not proposing to change its strategy for DPCR5 and would only consider doing so when it is apparent that there has been a fundamental shift in the labour market not just an increase in short term market volatility.

Objectivity of CEPA's contract labour RPE

CEPA presents evidence from the Annual Survey of Hours and Earnings (ASHE) that suggests that the wages of engineers have not increased significantly faster than average earnings in the economy as a whole since 1997.[22] CEPA also presents evidence to suggest that various indices measuring the costs of employing electrical and mechanical engineers (e.g. from BEAMA, BERR and JIB) have increased faster than average earnings.[23] It then presents the following anecdotal market evidence:

"*Over DPCR5 some research has suggested that one-off events such as the Olympics and the construction of Crossrail may create a significant additional demand for the contractors employed by the DNOs. However, the recession has already significantly reduced activity in the construction sector. Data released by the ONS in March 2009 suggests that the construction sector declined by a substantial 4.9% in the fourth quarter of 2008 alone. This will reduce significantly demand for labour with the type of skills employed by the DNOs over the medium-term, and thus significantly reduce the ability of contractors to negotiate higher wage growth than the general labour force. Indeed* ***anecdotal evidence*** *suggests that many individuals employed as contractors are currently accepting nominal wage cuts to keep their jobs with reports of workers accepting wage cuts of up to 20% to keep their jobs.*"

None of the projections or evidence presented in the above paragraph are forecasts of *real* wage inflation for electrical engineers, or any other type of labour that EDF Energy employs. The statements are not objective or verifiable and provide no basis for regulatory forecasts at DPCR5. CEPA provides no evidence in support of its forecast contract labour scenarios of 1%, 0.5% or 0% below the general labour RPE. They appear to be arbitrarily selected based on CEPA's subjective assessment of the anecdotal evidence quoted above.

The only reliable evidence CEPA presents shows that, on average, real contractor wages have grown historically at or above average earnings growth in the economy as a whole. Thus, the little evidence that CEPA does present on contractor rates supports our forecast contract labour RPE which is 0.9% above our forecast internal labour RPE.

7. Customers

Question 1: Do you agree with the proposed mechanism (in full) for worst served customers?

We welcome the fact that Ofgem has now based the allowance on the number of worst served customers in each DNO, rather than on an average per DNO basis. We are, however, disappointed that Ofgem has set the allowance significantly below the DNO forecasts. We remain concerned that for a proportion of customers the gap between them and the "average" customer will continue to increase.

Quality of Service interruptions incentive scheme (IIS)

Question 2: Do you agree with the proposed approach (in full) for setting unplanned targets for customer interruptions and customer minutes lost?

We welcome Ofgem's decision to base the start points on the lower of the current DPCR4 average or the DNOs FBPQ baseline. We are, however, concerned that the proposed targets, with the exception of CN West's customer interruption (CI) target, are tighter than the 2009/10 targets but that the achievement of these targets is not funded. If it was economically inefficient for a DNO to meet the 2009/10 targets we fail to see why it would be economically efficient to achieve harder targets. We do not understand why shareholders should pay for further improvements that customers do not value. To achieve Ofgem's proposed 2014/15 targets could require the DNO to either make inefficient capital investment or bear an ongoing financial penalty. Neither choice is tenable.

We note Ofgem's decision to include the amendments tabled in the December Paper in the benchmarking analysis. We welcome Ofgem's sharing of the detailed modelling so that DNOs can understand, and verify, how these amendments have been included in the benchmarking process.

We do, however, have concerns that LPN is still significantly disadvantaged by the current benchmarking process. Our concern is twofold:

- LPN targets, and CIs in particular, provide minimal headroom to accommodate random high impact events e.g. loss of a main substation serving high numbers of customers
- The relatively high impact of LV network performance for which no proper benchmarking has yet been undertaken

With respect to (1) above, we proposed in the December policy paper response that the exceptional event criteria need to be amended to recognise these scenarios. We note that Ofgem is looking to extend the mechanism to events that are within the DNOs control. We look forward to seeing Ofgem's detailed proposals in this area.

On the LV benchmarking issue it is easily observable, from the annual returns, that LPN's HV performance is delivering low CI and CML to the extent that LV performance dominates to an extent not seen in other DNOs. Ofgem therefore needs to ensure that an approach to LV benchmarking is developed that accurately reflects the challenges faced in LPN's highly urban environment (i.e. where there are many obstacles to improving physical response, such as traffic congestion, restrictions on access, and requirements for out-of-hours working only). The current overall benchmark is too simplistic and LPNs CML performance should not be penalised through unrealistic LV restoration targets.

Ofgem should also note that it may not be possible to reduce LPN HV CML/CI as far as the benchmark companies, as automation successfully restores customers in less than three minutes, reducing the CI count and removing a large number of potentially quick restorations from the benchmarking process. In those areas where LPN uses automation over half customers are restored in less than three minutes.

Ofgem's proposals on revenue exposure and incentive rates look appropriate. In particular, it is important that the revenue exposure is kept constant across companies to ensure that the risk profile is also kept constant. We are pleased that Ofgem has stated that this is its intention.

Given the output of the willingness to pay survey it would appear sensible for incentive rates across the DNOs to move to a more uniform rate. The exception is LPN where it is obvious that customers place a significantly higher valuation on not being interrupted. Ofgem's proposal to close half the gap in DPCR5 is pragmatic.

Question 3: Do you think that we should set a cap on the cost per benefiting customer within the worst served customers mechanism and, if so, what level should this be set at?

We understand Ofgem's concern that the allowance could be spent on a small number of customers. However, as the schemes have not been fully developed it is difficult at this time to identify an appropriate cap. But we do believe that any cap should apply at the portfolio level rather than the project level as this leaves the DNO the maximum flexibility.

8. Network Output measures

Question 1: Is Ofgem's proposed methodology for general reinforcement and asset replacement outputs appropriate?

We broadly agree with the proposed methodology for output measures for general reinforcement and asset replacement, as shown in the May document and discussed with the Network Cost Working Group

We look forward to working constructively with Ofgem to develop network output measures as part of the DPCR5 settlement.

We also welcome Ofgem's intent to use Tier Two Output Measures and we look forward to developing outputs further over the DPCR5 period.

We believe we should create common measures where possible, but acknowledge that there will be issues specific to each DNO.

We support the ultimate objective of establishing Tier One measures for use at DPCR6 which appropriately take into account both probability and the consequences in analysing overall network risk, acknowledging the considerable effort that this will require.

Output Measures based on fault rates must acknowledge the volatility inherent in the measure

Progress in developing Output Measures against the common framework

Load Index

We have replicated the methodology proposed by CN and agree that it is a suitable basis for development.

In terms of output measures, we question the value of post 2020 forecasts given the level of uncertainty beyond 2020 regarding:

- Electrification of heat and transport
- Growth of DG micro-generation (and the impact of feed-in tariffs)
- Further DSM and energy efficiency opportunities (including those arising from smart metering)
- The longer-term economic outlook

There are a number of issues to be addressed and we are keen to find pragmatic solutions which will enable Ofgem and the DNOs to move quickly towards agreeing a development path. These include:

- Representation of substation groups in the analysis
- Agreed best view of the Year 0 starting position

- Determination of forward view at Year 5
- Calibration of LI bands for 'at risk' thresholds
- Accommodation of different definitions between DNOs (e.g. in respect of overload capacity, firm capacity, weather/temperature correction)

We would support a move to synchronise demand forecasts so that RRP and SYS use the same data in the same year.

Non Load – the 'Health' Index

We have proposed a set of aggregated asset HIs for discussion.

We welcome Ofgem's acknowledgement that DNOs are at different stages of condition data collection, and that asset condition is not the only driver for asset replacement.

Forecasting condition degradation is possibly the greatest challenge in developing these measures, especially over a relatively short time period. Degradation from 'High' to 'Very High' Probability of Failure may be manageable, but the progress from 'Low' to 'Medium' to 'High' is not well understood at this time.

We shall state the assumptions underlining our best forecast of asset condition at the end of DPCR5.

We have proposed aggregated types of assets, and accept that some modifications may be possible to facilitate greater comparison between DNOs.

<u>Fault rate-based measures</u>

We believe that 5 year rolling average, using damage only, may be a reasonable basis for developing a measure for information only at this stage, since year-on-year fluctuations in fault rate, and the insensitivity of fault rate to network investment, are major concerns and barriers to adopting this as a true Output Measure.

Third Party damage (including proved latent damage) should be split out of this measure.

We would support a move to rationalise fault data between Output Measures and our current annually reported reliability performance.

'Other' measures

In February, we proposed a measure 'Proportion of customers at risk due to flooding' which would reflect the effective prioritisation of investment in flood risk mitigation and we also proposed a measure of oil lost/km of FFC in commission. We consider that there is a potential environmental measure around the bunding of major transformers.

We welcome the opportunity to work with Ofgem on further measures which add value.

Question 2: Is Ofgem's proposed approach for other areas of investment appropriate?

We believe that Tier 3 outputs (principally volumes achieved) may be the right fit for 'Other' investment areas given their relatively low materiality, but we should look for ways to minimise these.

Question 3: What approach should be taken if a DNO fails to deliver the agreed outputs i.e. how could the incentives be adjusted?

The process should focus on the DNO's justification for any failures and whether or not they are reasonable in the circumstances. For example, it may be that an asset category suffers an unforeseen and rapid deterioration in condition, possibly as a result of new assessment techniques, and it was not reasonably practicable to have accelerated the replacement of these because of valid constraints, such as outage windows.

Question 4: Do you consider that the output measures proposed provide sufficient protection in their own right, or is it appropriate to have some form of additional safety net in the DPCR5 settlement, for example through monitoring investment volumes?

Ofgem should focus on outputs and incentivise a DNO's management to determine what inputs are required, including the volumes of assets installed, in order to achieve them.

In addition, a volume based approach would have to deal with changes to the drivers impacting on them, for example load growth. Such an arrangement would be complex and resource consuming for both DNOs and Ofgem.

Question 5: Should there be an obligation on DNOs to further develop output measures during DPCR5?

No. The DNOs have responded positively to Ofgem's call for output measures, suggesting that an obligation is unnecessary.

Question 6: We seek views from stakeholders on the role that outputs should play in DPCR5 and particularly how they can best be implemented and used.

Outputs are at a very early stage of development and it is important that Ofgem and the DNOs are able to work together constructively to understand how they work and, therefore, how they may be improved to provide meaningful measures in the medium term.

At this stage of development, outputs are unsuitable for benchmarking or performance assessment. Stakeholders should understand that achievement of these developments is likely to take the whole of DR5 and require significant resources.

All parties must take care to avoid creating Outputs which encroach on each others' roles; for instance, Asset Management benchmarking. Outputs need to be focussed on significant areas of investment and areas which are not covered by other measures (eg Quality of Supply).

A guiding principle must be that an Output Measure will be a measure which an organisation will find useful for its own management purposes.

9. Cost Incentives

Question 1: Do you agree with our proposed approach to equalising incentives?

Yes, we strongly support Ofgem's proposal.

The current differential incentives on opex and capex can distort DNO behaviours in a number of unhelpful ways:

- Favouring capex solutions over maintenance (and increasing costs to consumers overall)
- Discouraging demand side management actions (and increasing costs to consumers)
- Favouring contracting solutions for capex that incorporate opex activities (undermining cost comparisons)
- Encouraging the badging of opex /indirects as capex (i.e. gaming)

The RRP process has already demonstrated that at DPCR4 there where material differences in accounting policy across the DNOs and that significant resource is needed by Ofgem to investigate cost boundary areas.

Equalisation of incentives also implies the use of symmetrical incentives on opex overspends which, particularly combined with the IQI mechanism, helps to mitigate the degree of error (discuss elsewhere in this response) inherent in Ofgem's opex benchmarking.

Question 2: Have we identified the most appropriate costs to be within the equalised incentive and the IQI?

Yes, we believe the most appropriate costs have been included within the equalised incentive and the IQI.

Overall Scope of IQI

The proposed application of the GDN matrix to electricity distribution represents a significant increase in risk to the DNOs, due to the tightening of the allowed expenditure calculation. Under the DPCR4 incentive the allowed expenditure ratio ran from 105% to 115%. This recognised that there was the potential for error in the consultants' forecast. At the GDPCR Ofgem tightened the allowed expenditure ratio to 100 to 110%. Its rationale was that the ratio was Ofgem's view rather than its consultants' view. But there is no evidence why Ofgem's forecast should be better than theirs.

Under the GDN matrix if a company forecasts more capital expenditure than the regulator then for every 1% of the difference the regulator allows 0.25%. At the time we stated that this was inappropriate, as it implied that Ofgem's forecast was practically perfect and significantly more accurate than the DNOs'.

However, there is a significant difference between the GDPCR and the proposed EDPCR in that DNOs will be required to deliver defined outputs, via their investment plans, and will be penalised for not achieving them. Therefore, in making its assessment of the correct level of investment Ofgem must also be confident that its proposed allowance will allow a DNO to meet its defined outputs. In our view this adds a further level of uncertainty into Ofgem's forecasting process which must be recognised in the setting of the allowed expenditure ratio. We believe that retaining the original DPCR4 IQI matrix would help overcome this additional uncertainty.

Question 3: How should we set the "RAV additions percentage" that will determine the split between split between "slow" and "fast" money?

Our initial view is that the split should be consistent with the DNO being able to comfortably maintain an A Grade credit rating whilst being able to pay an appropriate level of dividend.

10. Managing uncertainty

Question 1: What balance should we adopt between mechanisms to manage specific risks (such as input price uncertainty) and a more general type of re-opener to manage a wider basket of risks?

Our answer is combined with our response to question 2 below.

Question 2: What risks should be covered by specific mitigation mechanism, by a general type of reopener, and which should be left to the DNOs to manage?

We believe that the risks which DNOs are asked to bear in DPCR5 should not be materially different from those for DPCR4. This means that Ofgem should only introduce new risk management mechanisms where material new risks have arisen or can definitely be expected to arise.

In designing any new risk mitigation mechanisms we would expect to see a deadband which would encompass the degree of cost volatility seen in DPCR4. On this basis, there would be no case for Ofgem to reduce the cost of capital on the grounds of reduced risk.

Our current view is that additional protection will only be needed for:

- Debt cost volatility (where further as yet unknown repercussions of the Credit Crunch may reveal themselves).
- Changes to tax legislation (covered in our response to Ofgem's section on tax costs below).
- Material costs volatility (where a return to global economic growth may release pent-up demand and have significant impacts on commodity prices).
- Capex drivers for general reinforcement and connections (where the depth and duration of the recession may change demands significantly from the assumptions underlying our FBPQ capex programmes).

Given that this is a relatively short list of areas we see no need for a more general re-opener.

Ofgem should note that in reaching this view we assume that the following other mechanisms will be in place:

- Business costs – no protection
- Opex, ESQCR, network investment - IQI sharing factor
- Rates, licence fee – pass-through

- Pension costs – ex-post adjustment

Regarding pensions, we may want to revisit the question of whether a specific re-opener is needed in the light of Ofgem's proposals when we have seen them.

On the question of whether there should be one general re-opener mechanism or a set of bespoke ones we believe that it is easier to target new risks only with bespoke mechanisms. A generic approach would, by definition, apply equally to existing risks (for example a plant type-failure) and hence may have implications for the cost of capital, which is something we would not favour.

There are a couple of areas where Ofgem's paper needs clarification:

- In paragraph 10.3 Ofgem suggests that windfalls can dampen incentives for efficiency. This is of course not true since a windfall is a one-off gain that has no impact on other profit maximising opportunities.
- Paragraph 10.5 creates a spurious distinction between different risks in the first two steps. It is impossible to imagine any risk which is "outside of DNOs' control" but which they can "effectively manage" (better than consumers), so one or other of the first two steps is superfluous.

Question 3: Are there any additional risk mitigation mechanisms that we should be considering that are not identified in this chapter?

The existing special disapplication condition in the licence is often misunderstood. It is a last-resort provision under which the licensee can effectively trigger a price control review at five-yearly intervals, and thus restrict Ofgem's otherwise unlimited power to allow a particular price control to remain in force for the duration of the DNO's licence. This mechanism needs to be retained, perhaps with some adaptations to make it less onerous to operate, and to that extent it represents an additional risk mitigation measure of a kind not identified in this chapter.

11. Tax Methodology

Ofgem has requested responses to four specific questions in relation to the taxation methodology for DPCR5. These questions need to be considered as part of an overall strategic aim for funding taxation in an appropriate manner.

Overall Strategic Aim for Funding Taxation

It is our belief that tax should be funded as an operating cost. In doing so it is therefore important to forecast the actual cash tax cost as closely as possible and use this as the basis of funding. There may be reasons to diverge from funding the actual forecast cost itself, perhaps as part of an overall policy aim that encompasses more than just taxation. It is, however, important that if this is the case then these divergences are easily reconcilable back to commercial reality so that there is value in the RRP process.

If tax is not funded on a basis that is reconcilable to commercial reality then the RRP process becomes nothing more than an administrative exercise. Indeed, it is arguable in these circumstances that it is more appropriate to fund DNOs on a pre-tax basis than to fund on a post-tax basis where the cost of taxation is not effectively modelled.

It is also important that the modelling of taxation is fair and transparent. The methodology for funding should be symmetrical. For instance, if a DNO gets a benefit from out performing then it should similarly suffer a penalty for under performing. Also, costs allowed in calculating the tax charge should be allowed in exactly one price control period. Furthermore, where simplifications are made in modelling taxation, these should not arbitrarily benefit or penalise DNOs based on their own individual cost profiles.

Ofgem has stated that it wishes to mitigate the tax risk faced by DNOs. If this is the case then there needs to be transparency over how that perceived mitigation of risk is factored into the agreed cost of capital. There also needs to be agreement that perceived risk actually has been mitigated.

Question 1: Is the approach to modelling DNOs' capital allowances on a common basis representative of the industry position and does it ensure that no individual DNO is materially advantaged or disadvantaged by this methodology?

Consideration needs to be given to two main points here: (1) is there a strong rationale to fund DNOs on a common basis rather than based on their own specific expected costs, and (2) if a common approach is taken then how can it be ensured that the approach is transparent and fair?

Considering (1) first: There are very strong arguments to say that tax should be funded using the specific approach. It is not possible to reduce tax costs in the way that it may be possible to make efficiencies to other costs. EDF Energy's DNOs have agreed capital allowance treatments for capital expenditure with HMRC and it is not possible to change these just because Ofgem wishes to incentivise the DNOs to reduce their cash tax charges. Clearly, there are areas of capital expenditure where the tax treatment is less clear cut than others. But a DNO's primary objective around taxation is always to meet its legal obligations. Ofgem should be very wary of either encouraging or being seen to incentivise DNOs to depart from what is legally acceptable and consistent with UK tax law.

That said, there clearly are differences in how the different DNOs treat certain areas of capital expenditure. A DNO that treats a particular category of expenditure in what is perceived to be a less efficient manner should be looking at how that treatment can be improved, and the fact that other DNOs treat this expenditure differently should be grounds to at least enter into discussions with HMRC. However, a DNO is incentivised to do this anyway, even if funded on the basis of a specific approach, as it is still able to outperform against its allowance for the remainder of the current price control period.

Moving onto (2): Whatever the reasoning, Ofgem do appear to be strongly in favour of the common approach. If such an common approach is taken, it is clearly important that the approach is transparent, correctly calculated, and fair. We are concerned that the approach taken so far is none of these. The calculation of the percentages disclosed in table 11.1 is not transparent, is certainly not yet correctly calculated (although this may just be a result of the complexity of the calculation), and leads to bias in the treatment of capital expenditure that could unfairly benefit (or disbenefit) some DNOs compared with others.

EDF Energy believes that the most appropriate way to apply capital allowance percentages to agreed capex is at the detailed level given in table 8 of the Financial FBPQ. This is actually a much simpler and clearer calculation than the one currently undertaken, as there is no need to cut and consolidate the percentages, and hence it greatly reduces the risk of errors creeping into the calculation. Furthermore, this would avoid the apparently arbitrary splits of expenditure into six categories of costs.

It appears strange, for example, that Tree Cutting has its own percentage whereas something as material as asset replacement, which itself can be analysed into very different categories, is wrapped up inside the generic heading of 'Non-Load Related'. The fact that very different types of expenditure appear under single headings means that there is scope for very significant departures from commercial reality in applying the percentages. This would not be the case if expenditure was analysed at a more appropriate level of detail that is already fully available to Ofgem.

We understand that Ofgem is reluctant to move to the level of detail given in table 8 but strong consideration really does need to be given to moving to more sensible groupings even if this is at as high a level as that given on table 8a of the Financial FBPQ.

In summary, on the basis that it is very likely that Ofgem will take the common approach, despite opposition, it is imperative that the average percentages used are transparently & correctly calculated and result in a fair outcome. In particular this means that the percentages applied to capex must be applied at a much more detailed level than is currently proposed.

Question 2: Views are invited on whether the most appropriate option for the tax treatment of re-openers is the case-by-case approach.

EDF Energy agrees that the most appropriate approach for the tax treatment of re-openers is on a case by case basis. As the tax treatment of costs under different re-openers could differ greatly, this would appear to be the only appropriate approach.

Question 3: Should the DNOs retain the risk and rewards for all amounts below/above the trigger threshold; or for the entire amount rather than the excess over the materiality trigger; and what should be the appropriate timing of adjusting DUoS revenues following both single and multiple trigger events.

As our response below shows, the issue of the trigger mechanism is much wider than the specific issues raised in this question.

It is stated in the Tax Methodology that Ofgem is minded to introduce a trigger mechanism to mitigate uncertainty. EDF Energy supports this but believes that for such a mechanism to work it must satisfy certain key criteria:

1. It must genuinely remove material risks
2. It must clearly define whether an event falls within or outside the scope of the mechanism
3. It must be simple and transparent to apply
4. It should be fair to both DNOs and to customers
5. The effect of the reduction in uncontrollable risk to the DNOs on cost of capital must be clearly calculated and explained.

Looking at each of these in turn:

1. On 26 February 2009 we submitted to Ofgem a definition of what we believed should constitute 'legislative change' for the purposes of the trigger

mechanism. This definition was designed to capture the major areas that can cause changes in a DNO's cash tax liability but which are outside the DNO's control. This definition is repeated almost verbatim in section 1.31 of Appendix 14 to the Methodology:

- Any change in legislation that alters the cash tax charge for the DNO in the current price control period, and should specifically include changes in the relevant legislation whether introduced in a Finance Act, other Act of Parliament, Statutory Instrument or other legislative instrument
- Changes in, or clarifications to, HMRC interpretation of legislation
- New precedents set under case law
- Changes in accounting standards that have a knock-on effect on the quantum or timing of taxation.

Ofgem has agreed that the first of these bullet points should form part of the mechanism for mitigating uncertainty but does not believe that the other three bullet points are sufficiently measurable or material to require inclusion. We are very concerned by this extremely narrow definition because we believe that it leaves significant risks with the DNOs, not least because the most significant change in the taxation of the DNOs in the last 20 years was the introduction of deferred revenue expenditure – something that arose from HMRC interpretation of case law. Thus changes in case law and HMRC interpretation are clearly material enough to be included in the definition of legislative change. We are concerned by Ofgem's apparent view that whilst a DNO would immediately raise an issue about a change in legislation that was detrimental to the DNO, it could keep quiet if a change in legislation was favourable. Whilst clearly it is harder for Ofgem to be aware of all changes in case law and legal interpretation than what is published in Finance Acts, it is in a DNO's best interest to inform Ofgem of the change even if it is favourable. This is because a change that is material enough to trigger the mechanism would be readily identifiable from the tax computations, which are submitted on an annual basis to Ofgem.

We understand Ofgem's belief is that DNOs should be prepared to fight through the courts where changes in case law / interpretation have adversely affected the DNO. Ofgem should understand that the majority of DNOs are part of larger vertically integrated utilities where power plants are also likely to be affected by any such change. There is therefore a direct incentive for the owners of the majority of DNOs to fight such changes through the courts.

However, an understanding of the legal process needs to be considered here. If a decision is decided in court this becomes law. This cannot directly be challenged by a third party. For the DNO to legally and correctly avoid applying a piece of case law, it has to be able to distinguish its own facts from the facts of the case.

Therefore the case either applies and it cannot be challenged by a DNO or it does not apply and hence is not relevant for the trigger mechanism.

Clearly there could be future differences of opinion with HMRC about whether the case applied, and that difference of opinion could be challenged through the courts. Changes in HMRC interpretation are different from changes in case law and, provided it was felt that the interpretation was not consistent with tax legislation, could be challenged more directly. What EDF Energy is not prepared to do is to harm its reputation with HMRC and lose its low risk status.

2. The definition of legislative change as given above is quite clear as to what should and should not be included within the scope of the mechanism.

3. EDF Energy agrees with Ofgem's view in paragraph 1.37 of Appendix 14 on how the trigger mechanism should be applied.

4. The methodology as stated is symmetrical and as such is fair to both DNOs and customers.

It is a fundamental requirement that the effect of the reduction in uncontrollable risk to the DNOs on their cost of capital must be transparently calculated and explained. Clearly one would expect a reduction in cost of capital if there is a reduction in risk. What is not clear is if and how tax risk was priced into DPCR4. The DNOs as a group asked for a similar trigger mechanism at DPCR4 but this was ignored – presumably this means that Ofgem felt that tax risk was too low to be an issue. If this is the case then one would not expect a reduction in cost of capital to arise from the introduction of the trigger.

EDF Energy believes that the materiality level of the trigger is currently set too high. 0.5% of base revenue should be an absolute maximum level of trigger. Even at this level Ofgem is leaving significant tax risk with the DNOs.

Having considered our position further, we believe that it would be appropriate and simpler to aggregate all legislative changes within a regulatory year and consider whether these in total breach the trigger. This avoids potentially having to rerun the model several times within one regulatory year.

Moving onto Ofgem's specific questions concerning the trigger, EDF Energy's only comment at this stage is that the basis of the trigger mechanism must be in line with other triggers within the overall package.

Question 4: We invite views on the practicality of communicating the likelihood of a trigger being activated and the methodology for it.

The likelihood of a trigger being activated is difficult to forecast. If the DNOs were able to predict future changes in legislation then there would not actually be any tax risk. Therefore Ofgem needs to look historically at what kind of changes would have triggered the mechanism. Had a trigger been in place for DPCR3, then probably the only change that could have triggered it was the introduction of deferred revenue expenditure referred to above. As things turned out, it was possible to negotiate that this would not apply for DNOs until the following review period and so the trigger would not have been breached. It is to be expected that the changes to the mainstream corporation tax rate and the adjustments to the rates of capital allowances and possibly the abolition of IBAs would all have breached the trigger. As well as these, the introduction of an integral features rate may have breached the trigger. These were introduced in two finance acts and so, in line with the answer given to question 3 above, the trigger would have been breached twice. This is an average of once each for the last price control periods. EDF Energy does not disagree with the introduction of a requirement to notify Ofgem of a potential breach of the trigger in the licence. However, as there will be overlap in key stakeholders between the different DNOs, it would seem appropriate for Ofgem to collate notifications and inform all concerned.

Further Comments

EDF Energy has a number of further comments relating to the tax sections of the methodology:

Opening Tax Written Down Values

Ofgem has suggested that the most appropriate method for calculating the opening tax written down values ("TWDVs") for DPCR5 is to use the forecasts for real opening TWDVs included within the Financial FBPQ, subject to any adjustment necessary for revisions arising from HMRC enquiries. This has the advantage of simplicity and easier reconcilability between RRPs and reality.

As Ofgem notes, there was considerable disappointment expressed by DNOs at the generic method used by Ofgem for calculating capital allowances for DPCR4. The impact of this is that, in reality, capital allowances have been claimed on assets that were forecast as being expensed and hence 100% deductible by Ofgem. This results in real TWDVs containing the residue of expenditure that has already been fully allowed by Ofgem. Therefore, in using forecast real opening tax written down values as the opening position for DPCR5, Ofgem will be allowing the expenditure for a second time. Whilst this is not equitable to all DNOs, we accept that to bring the TWDVs on to a real basis is beneficial in the long run. On this occasion we believe that there should be a true-up.

An alternative approach would be to take the agreed opening TWDVs from DPCR4 and then roll these forward using real capex from DPCR4 but applying the agreed DPCR4 percentages. This would ensure that expenditure will be allowed once and once only. The major disadvantage of this method, however, is that it requires a more detailed reconciliation to be produced when reconciling RRPs to submitted computations as well as diverging regulatory TWDVs away from reality.

Capitalised Indirect Costs

EDF Energy is pleased that Ofgem has understood the need to model indirect costs using DNOs' actual accounting policies. The treatment adopted for DPCR4 was a major contributing factor to the issues affecting opening tax written down values. The approach now being taken will model capital allowances on a basis much closer to commercial reality.

Corporation Tax Instalments

EDF Energy notes Ofgem's move to fund corporation tax in line with the timing of quarterly payments. In essence, this means that the first half of the 2010/11 regulatory year will be funded based on the last six months of 2009/10, with funding then continuing effectively six months in arrears. Whilst this is expected to be marginally detrimental to EDF Energy, it makes sense in terms of the bigger picture of trying to model corporation tax as closely as possible to reality. We therefore support Ofgem's methodology.