ELECTRICITY DISTRIBUTION PRICE CONTROL REVIEW

INITIAL CONSULTATION

THE RESPONSE FROM CE ELECTRIC UK FUNDING COMPANY (CE), NORTHERN ELECTRIC DISTRIBUTION LIMITED (NEDL) AND YORKSHIRE ELECTRICITY DISTRIBUTION PLC (YEDL)

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CONTENTS

SUMMARY 1
INTRODUCTION 11
ENVIRONMENTAL ISSUES 11
Supporting the transition to a low carbon economy 11
DG and related incentives 13
GDUoS charging 14
Transmission access for DG 15
Non-network solutions 16
Other DG issues 17
Energy efficiency 19
Losses and the unit driver 20
Other carbon footprint considerations 23
Emissions 24
Other Environmental Issues 25
Visual amenity 25
Meters 27
CUSTOMERS 29
Customer priorities 29
What do customers want? 29
Current Arrangements and Development for DPCR5 30
Complaints 30
Quality of service – IIS 30
IIS in DPCR5 30
IIS incentive rates 31
DPCR5 IIS starting point 31
Network resilience 32
'Poorer performing' DNOs 32
Exceptional events 32
Planned interruptions 32
Voltage quality 32
Guaranteed standards 32
Quality of telephone response 35
Scope of survey 35
Discretionary reward scheme 35

Telephony scheme – automated messaging 36
Survey attributes 36
Pilot surveys 36
Connections 36
Introduction of new standards 36
Introduction of an incentive scheme 37
Commitment to supporting competition in connections 37
Improving customer service within the connections process 38
Regulating the level of connection charges 38
NETWORKS 39
Network cost assessment 39
Costs and delivery 44
Capex incentives 44
Input prices 47
Delivery 47
FINANCIAL ISSUES 47
Cost of capital 47
Approach to cost of capital 48
Financeability and financial modelling 50
Financeability adjustments 51
Depreciation 51
Financial modelling 52
Profiling 52
Protecting against financial failure 52
Treatment of taxation 52
Claw back of tax benefits of excess gearing 53
Gearing assumption 53
RAV 54
Treatment of excluded services 54
Finalising DPCR4 RAV 55
Revenue adjustment 55
Treatment of pensions 56
PROCESS AND TIMETABLE 56

SUMMARY

The Ofgem publication *Electricity Distribution Price Control Review: Initial consultation document* (the *Initial consultation*) comprehensively sets out the key issues that face Ofgem and the sector at the fifth price control review (DPCR5). The main points from our full response are set out in this summary.

ENVIRONMENT

CE supports Ofgem's efforts in the transition towards a low-carbon economy and we believe that distribution network operators (DNOs) have an important role to play in this.

We believe that DNOs could and should play a role in supporting the transition to a low-carbon economy, specifically:

- facilitating the connection of distributed generation (DG);
- offering 'energy efficiency' advice focussed on network issues;
- reducing energy lost in distribution;
- reducing the carbon consumption of operational and non-operational premises; and
- reducing the carbon consumed in our operations by transport and mobile plant.

Overall, we submit that evolution rather than revolution is required for the regulatory framework at this review. However, Ofgem must use the Long-Term Energy Network Scenarios (LENS) project and similar work to set the foundations now for the solutions, radical or otherwise, we will need in place to meet 2050 emissions targets.

The DG and related incentives should be reformed…

Reforming the DG hybrid funding mechanism to create a real incentive, and increasing existing incentives to capex efficiency, will encourage distributors to seek out novel solutions to reduce connection costs.

Reforming the Registered Power Zone (RPZ) scheme to encompass demand and managing the network on an ongoing basis, combined with a change of driver from megawatts (MW) connected to capex deferred, would increase the potential of the scheme to bring forward novel solutions.

…with changes to the main price control to reflect the benefits of deferred investment.

A reformed DG hybrid funding mechanism should be combined with the main demand price control to permit generator use of system charging that properly reflects the benefits of deferred reinforcement.

Transmission access for DG needs to be settled now…

Enduring roles and responsibilities for transmission access for DG need to be settled now, so we can build for the future.

The Great Britain System Operator (GBSO) should manage the transmission system, working with suppliers through the existing balancing mechanism processes to manage transmission constraints.

…giving distributors responsibility for managing their capacity requirements and strengthening incentives for capex efficiency.

Distributors should manage their systems, including their capacity requirements at transmission connection points. Increasingly, this could involve novel solutions to defer reinforcement, if adequately rewarded through reforming the DG hybrid funding mechanism and strengthening existing incentives to capex efficiency.

Distributors should be funded to provide energy efficiency advice.

Distributors can complement existing energy efficiency advice provided by suppliers.

The focus should be upon the half-hourly metered market, particularly in areas of restricted network capacity.

Clear funding is required, potentially through strengthening existing incentives to capex efficiency.

Reforms are needed to the losses incentive…

As things stand, total system losses can be neither measured nor modelled robustly. The rewards for improving system losses are masked by movements in the data from the settlement system. This does not diminish the incentive properties of the current arrangements but the incentives that are appropriate for system losses are of a different order of magnitude from the incentives that should apply to improvements that result from better data.

We suggest that these issues be decoupled, leading to two separate incentive schemes. Technical loss reduction can be subject to an incentive based on modelling the losses impact of discrete capital investment schemes. The benefits from improved settlement data should continue to be incentivised, although at a lower rate.

…and the kilowatt-hour (kWh) revenue driver should be replaced.

The kWh revenue driver in the present price control formula should be replaced by something more reflective of costs and that does not have the undesirable environmental connotation of appearing to encourage increased energy consumption.

Incentives for a DNO to reduce its carbon footprint are appropriate.

A simple but effective scheme to encourage reduced carbon emissions could be established for the activities of the licensed distribution business, however structured, applying the principles of existing Department for Environment, Food and Rural Affairs (DEFRA) work including the Carbon Reduction Commitment (CRC):

- own-consumption at metered non-operational and major operational sites (which also addresses the issue of accounting for such energy use); and

- mobile plant and all road transport, converting usage to CO_2 equivalent.

The transmission incentive on sulphur hexafluoride (SF6) should be applied to DNOs…

The incentive for reducing leakage of sulphur hexafluoride (SF_6) incentive used within the electricity transmission sector should be applied to electricity distribution businesses with a pragmatic and robust reporting process based upon SF_6 top-ups.

...with a fluid-filled cable integrity incentive.

Although not a greenhouse gas issue, the loss of insulating fluid from fluid-filled cables is a significant environmental risk. Accordingly, a fluid-filled cable (FFC) incentive should be introduced, based upon the volume of oil discharged into environmentally-sensitive areas, as a percentage of the total volume of oil in fluid filled cables in such areas at the start of the DCPR5 period.

Visual amenity cost allowances need to be reviewed.

The stakeholder consultation should play a significant part in determining the future extent of undergrounding for visual amenity.

Unit cost allowances should be revisited, as they are currently insufficient. This is particularly acute if visual amenity becomes a key driver of activity as part-funding from the asset replacement budget becomes less appropriate.

The incentive scheme should expand beyond existing feeders, to avoid erecting new lines where existing lines have been undergrounded, and avoid creating feeders that have been undergrounded piecemeal with consequent reliability issues.

DNOs are able to play a central role in the implementation of a smart meter programme…

Ofgem should reconsider its objection to regulatory arrangements that are designed to encourage DNOs to play a role in delivering smart meters. There is a growing belief that the time is ripe for action on smart meters and that the DNOs are best placed to take on at least a significant proportion of this role.

The advent of smart meters has potential consequences for several aspects touching on the commercial arrangements of the sector, such as the design of the settlement system. There is likely to be an expanded role for DNOs that will arise from the smart meter implementation.

…and stranding protection is necessary for legacy and non-legacy meters.

Stranding protection of the kind provided for ‘obsolete’ prepayment meters should be provided for legacy meters, provided pursuant to a licence obligation, that are now replaced due to a smart meter roll-out.

To secure the continued provision of non-legacy meters, similar stranding protection should be provided to give some certainty of recovering new investment.

CUSTOMERS

Our formal stakeholder consultation is commencing…

We are undertaking formal stakeholder consultation with our key stakeholders. Our primary focus must be on customers themselves as they are the stakeholders who ultimately have to pay for the operation of the network and who have to be satisfied that they are getting a cost-effective service, focusing on issues of importance to them. Due regard must also be had to other stakeholders who do not have to pay for the service that we provide (other than in their role as individual customers themselves) but who nevertheless have an interest in our activities.

…and the outcome will be reflected in our business plans.

The responses from stakeholders will be used to develop and prioritise specific costed options for further discussion with the stakeholders in late summer 2008 with the aim of using this dialogue to assist in the finalisation of our plans.

The interruptions incentive scheme (IIS) needs fundamental revision.

In our view the *Initial consultation* completely misses the fundamental issues associated with IIS continuing in its present form. We consider that there should be a thorough review of IIS to determine its relevance to customer needs and whether it ever has encouraged, or will continue to encourage, appropriate behaviour by the DNOs. In coming to this conclusion, we have looked closely at how IIS has been working in the DPCR4 period and believe there is now sufficient evidence to demonstrate that some significant adjustments to the scheme are required if it is to continue into the DPCR5 period. The evidence is extremely detailed and we look forward to specific discussions with Ofgem on this matter.

In particular, we would suggest that the IIS targets for DPCR5 cannot be set in the same way as at DPCR4 since this methodology takes no account of the cost/performance balances that an efficient DNO would have undertaken over at least the period that IIS incentives have been in effect.

Furthermore, the lack of any major regional signals in the recent willingness to pay survey would suggest that the wide variations in incentive rates which are a characteristic of the present IIS should not continue into DPCR5.

Voltage quality is not an issue for customers.

There is generally very little public concern over voltage issues as clearly demonstrated by the very low number of voltage complaints received by DNOs. We agree with Ofgem that further standards are unnecessary.

Compensation under the guaranteed standards needs to be reconsidered…

There is a lack of clarity about the purpose of the guaranteed standards scheme. If the standards are set at the level of performance that an efficient DNO should be able to meet in all cases this has implications for the level of costs that the DNO will incur in meeting the standards. If, however, the standards are set at a level that it is not reasonable for the DNO to meet in all cases – for example because it would be uneconomic to do so – the DNO will incur costs in making payments under the scheme to the customers that do not receive the prescribed level of service. The efficient level of such payments would have to be anticipated or allowed for *ex post* in the funding of the DNO.

Either approach could be rational but care must be taken to ensure that the two approaches are not confused.

…and there should be a cap on exposure to the guaranteed standard on supply restoration.

We propose some cap on DNOs' exposure under the guaranteed standard relating to supply restoration under normal conditions (EGS2), either through the regulations themselves, or permitting recovery of costs above a reasonable threshold through the price control.

Reducing the number of multiple interruptions requires ring-fenced funding.

For multiple interruptions due to higher voltage faults, we propose that such situations be covered by a similar scheme to that being applied to fund the undergrounding of overhead lines. DNOs should be allowed to invest a modest amount to improve the reliability of supply in areas experiencing a high number of interruptions.

DNOs should include Ofgem's survey questions in their own surveys of customers...

We support the view that DNOs should incorporate Ofgem's survey questions within their own surveys and recover relevant costs for this. We believe that the most appropriate mechanism would be for all DNOs to be required to undertake a core set of survey questions with the option to ask customers further questions to help understand and target wider performance improvements. It is preferable for DNOs to be able to survey customers much sooner after the restoration of the supply than is presently the case.

…and the telephony scheme should be extended to cover automated messaging.

We support the extension of the survey to include those customers who reach an automated message. Potential data protection issues and some technical issues may need to be resolved in order that these customers can be surveyed.

Speed of response should be measured rather than surveyed…

Confusion arises when customers rate the response of engineers in relation to restoring their supply rather than the speed of telephone answer response. The removal of a speed of response question would alleviate this to a great extent without loss if it were substituted with the measured speed of response figures from call centre reporting systems.

…and new questions should be properly piloted.

If new surveys or additional questions are to be carried out, we would like to see pilot surveys carried out before any new questions are included within the incentive regime. The survey questions should be consistent over time.

The discretionary reward scheme works well.

Improving communication with customers and other key stakeholders is covered within the current discretionary reward scheme submission and we understand this scheme is set to continue into the next price control review period. We believe that the current scheme works well.

Introduction of new standards or incentives for connections is appropriate.

We agree with Ofgem's proposal to review the effectiveness of the new licence condition (SLC15) and the progress DNOs have made on customer service improvements to all connections customers.

In principle, we would be supportive of a broader incentive-based connections-related performance regime. We would be keen to consider the method by which incentives are assessed and to understand the gap that presently exists (if any) between our current performance levels and those likely to be set under an incentive-based framework.

We are committed to supporting competition in connections…

We are committed to facilitating competition in connections in line with market and Ofgem requirements. We would like to understand better Ofgem's rationale for seeking further separation of connections activity within the licensed business and how this would benefit customers and those who depend on us to provide non-contestable services.

…and improving customer service within the connections process.

Another measure of customer satisfaction that Ofgem may wish to consider would be through the use of appropriately structured independent customer satisfaction surveys, not dissimilar in concept to the framework in place within the current IIS regime associated with the telephony service. We would be willing to work with Ofgem in developing this approach further within the price control review.

Any regulation of the level of connection charges must ensure that cost recovery is achieved.

Our connections charging methodology and pricing approach are based on recovering reasonable costs incurred in providing the connection. Any price cap for connections would have to ensure that all reasonable costs incurred would be recovered through use of system charges if they were not to be fully recovered directly from the customers requesting the connection.

NETWORKS

Benchmarking to determine efficient costs is possible only where certain criteria are met.

Benchmarking can help to inform a price control review provided *all* of the following criteria are met:

- the data on which the benchmarking is based is truly comparable;
- the firms that have the lowest, or the lower, costs must be worthy of emulation (bearing in mind that lowest cost is not necessarily best); and
- the specification of the benchmarking model must accurately capture the factors that drive the costs that are the subject of the analysis.

No benchmarking exercise carried out by Ofgem for the DNO sector has ever satisfied these criteria.

It is inappropriate to benchmark subsets of costs.

Moreover, after 18 years of incentive regulation it is inappropriate to attempt to carry out detailed benchmarking of subsets of costs. The building block approach should be used to help understand each DNO's assumptions and to test its plans having due regard for the assumptions upon which the forecasts are based and the definitions of costs included within those forecasts.

Ofgem must avoid:

- using benchmark comparisons to compare DNOs' forecasts;
- cherry picking what might appear to be best practice in individual areas; and
- using the outputs of crude forecasting models to assess the efficiency of DNOs' plans.

Rewards and penalties under the sliding scale need to be increased...

The up-front reward for accurate forecasting under the information quality incentive (IQI) – sometimes known as the sliding scale - should be increased as the current incentive does not sufficiently discourage overly prudent forecasting by DNOs.

To reduce the potential to distort decision-making, all network costs should be treated equally, in terms of the regulatory asset value (RAV) and the ongoing capex efficiency element of the IQI.

…and the scheme should be asymmetric for truthful forecasters.

Ofgem should introduce asymmetric exposure to underspend and overspend, particularly to DNOs with a proven track record of truthful forecasting.

Input prices are rising sharply.

It is clear that global demand for raw materials and finished products has created input price rises that are above those of the retail price index (RPI), and will continue to do so. We note the allowances Ofgem granted to the gas distributors, and it is essential that the upward cost pressures in electricity distribution are fully recognised.

Workforce renewal is a significant new cost at DPCR5.

We are confident that we will have plans in place to ensure adequate internal capability and/or contract coverage to meet the delivery requirements of our forward plan. It is appropriate to allow additional funding at DPCR5 to facilitate workforce renewal (recruitment and training) as this is a significant cost that is not reflected in any DNO's current cost base.

FINANCIAL ISSUES

The cost of capital approach taken at previous reviews should be maintained at DPCR5.

In setting the cost of capital for the DPCR4 period Ofgem recognised the important incentive it gave to supporting the investment needed during the period. These incentives are just as important as we enter the DPCR5 period and therefore will need to be maintained.

Stability in the cost of capital is important to investors. We are supportive of maintaining the traditional approach to the cost of capital with any incentive mechanisms being separately constructed.

We appreciate that there is a degree of circularity in that the cost of capital must reflect the degree of risk being borne by the business and therefore the finalisation of the cost of capital comes later in the process.

Nevertheless, we have concerns that Ofgem's timetable provides only one opportunity for consultation on the cost of capital and this occurs after the publication of the initial proposals.

Moves to improve the cost of capital estimation process, such as the introduction of indexation and triggers, introduce additional complexity which could damage the current incentive properties.

Ofgem needs also to give further consideration to the proportion of debt that is assumed to be index-linked. Such a consideration should avoid any outcome that penalises DNOs that have made reasonable decisions at the points when they have refinanced their activities.

Indexation of the cost of debt is inappropriate.

The indexation approach to the cost of debt proposed by some commentators is flawed and would encourage inefficient financing of DNOs. Certainly we do not consider that any of the recent transactions involving utility assets suggests that such a mechanism is now appropriate.

Financeability adjustments should not be necessary if the other parameters have been correctly set.

We consider that it is essential that Ofgem commits to providing an appropriate cost of capital over the regulatory lives of the assets.

If there is a need for financeability adjustments this would suggest that the settlement being proposed, as measured during the next regulatory period, is flawed.

Provided that the overall package reflects appropriate assumptions on the level of achievable costs, the timing of cash flows and the cost of capital, there should be no need for a financeability adjustment to be made in respect of any DNO.

Profiling of income should ensure a smooth trend during the period.

The profile of allowed income can be a significant issue at the junction of two reviews, particularly where there is an upward movement required in allowed income. A smooth trend (whether up, down or flat) of allowed income within a regulatory period provides stability to customers. Provided the profile is incorporated in the setting of the allowed income then the result will be net present value (NPV)-neutral within the regulatory period.

Protecting against financial failure requires further thought to be given to the ring fence.

The *Initial consultation* makes reference to the licence arrangements that are designed to protect customers and the regulatory regime from the consequences of a financial failure of a licensee. We look forward to participating in discussions with Ofgem about any changes that may be proposed to protect the regulatory regime in the light of recent transactions and the experience of the financial services sector.

Taxation should be DNO specific…

The assumption made at DPCR4 that capital expenditure (measured on a statutory basis) could be allocated to the different tax allowance pots on the basis of generic proportions was inappropriate.

Estimates of taxation should reflect, as closely as possible, the circumstances, both historical and prospective, of individual companies.

…and a tax correction mechanism may be necessary for unexpected changes in law.

We recognise the need to consider whether a tax correction mechanism is workable if significant changes take place in the legislation as applied to the tax rate or calculation of allowances.

Ofgem's gearing assumption should not promote further moves to a thin equity model…

We expect Ofgem to settle on a gearing assumption that does not promote further moves to a thin-equity model.

We expect the requirement for the DNO to maintain an investment grade credit rating to continue. This suggests that gearing below 60 per cent should be assumed as this would provide an appropriate margin to ensure that the allowed cost of capital provides an incentive to stay within this level.

…and the premia paid in recent transactions is no indication of the true cost of capital.

Valuations of RAV reflect the expenditure incurred that will be paid for by future customers. In this respect it is a 'regulatory IOU'. The value of this IOU is influenced by the application of the rules defining 'RAV additions' (as opposed to 'opex') and asset lives.

In assessing the real level of RAVs, and the consequent impact on the cost of capital, Ofgem must not be influenced by the excessive premia paid in recent transactions to acquire regulated assets.

Overall returns expected by investors have not declined over recent years. Looking forward, the ever-changing business environment and the additional requirements that DNOs will be expected to satisfy indicate an increasing degree of risk that must also be reflected in the cost of capital.

The treatment of excluded services should not discourage innovation in the customers' interests.

The *Initial consultation* indicates that further thought is required about the treatment of excluded services. Reducing the opening RAV to reflect the excess of actual income over forecast income is in line with the final proposals for DPCR4 but it has the effect that any revenue received above the forecast is removed. There is therefore little advantage in delivering increased levels of service in this category. Such an outcome has the perverse effect that it discourages DNOs from providing improved services that customers may value and for which they are prepared to pay.

The closing DPCR4 RAV needs to reflect the resolution of the outstanding issues of definition…

Reference is made in the *Initial consultation* to the need to adjust the closing value of the DPCR4 RAV to reflect discussions that are continuing on matters of interpretation. We are pleased to note that Ofgem is aware that there are outstanding issues that need to be resolved to provide the appropriate starting point for the DPCR5 period.

…but there is no reason to adjust the RAV of NEDL or YEDL for outturn capex in 2004/05.

There are no grounds for making any reduction to the RAV of NEDL or YEDL in recognition of the difference between assumed and actual capex in 2004/05 as Ofgem did not disagree with our view that that these amounts were not material.

A correction mechanism continues to be needed for pension costs.

Pension costs are a significant long-term issue. Since the Northern Electric group of the Electricity Supply Pension Scheme (ESPS) has been closed to new members for over ten years, the costs of funding this scheme are to a large extent outside our direct control. The frequency of valuations (which are out of synchronisation with review periods) and the uncertainty of markets ensure the continued need for some form of correction mechanism.

PROCESS AND TIMETABLE FOR THE REVIEW

Ofgem should commit to publishing a September update…

We broadly support the process as set out by Ofgem, however, we maintain that the September 2009 checkpoint should include an update paper (or some other formal quantified published statement) as well as the proposed workshop.

…and give more clarity about how it intends to use its working groups.

The area where we would wish to see more clarity is in the processes and working groups that will ensure the policy is effectively converted into practice. We wish to see co-ordination of the various Ofgem workstreams and clear milestones established in each area so that DNOs may contribute fully to the process.

Ofgem should plan to include firm commitments about the future treatment of expenditure incurred during the DPCR5 period.

Incentives depend upon clarity. At DPCR4 we proposed that Ofgem should set out clearly how expenditure incurred during the DPCR4 period would be treated at DPCR5 insofar as this could be done without fettering the discretion of the Gas and Electricity Markets Authority (the Authority). This resulted in Appendix 1: RAV Roll Forward and Incentive Mechanisms of the DPCR4 *Final proposals*. This Appendix has been useful but it could have been better still if it had been clearer about Ofgem's commitments. We therefore recommend that, at DPCR5, Ofgem should make clear from the outset that it intends not only to determine allowed income for the DPCR5 period but also to give very clear commitments about the future treatment of expenditure that will be incurred in the DPCR5 period. This is especially important in the light of the 'RPI@20' project.

Full Response

INTRODUCTION

1. Set out below are the views of CE, NEDL and YEDL in response to the *Initial consultation*.

2. We have followed the format of the *Initial consultation*, providing our response to the issues raised under the broad headings:

    - Environmental issues;
    - Customers;
    - Networks;
    - Financial issues; and
    - Process and timetable.

ENVIRONMENTAL ISSUES

3. The approach laid out below reflects the ‘environmentally-aware operation’ we discussed in our response to Ofgem’s May 2007 open letter, although we remain willing to consider more radical solutions. As well as the incentive on SF_6 leakage we mentioned then, we propose here a focussed incentive on reducing energy lost in distribution, reflecting the higher value of carbon we mentioned then, and (new to the discussion in this paper) sharper incentives to reduce capex generally.

Supporting the transition to a low carbon economy

4. The *Initial consultation* asks, in the preamble to chapter 2 (Question 1) ‘Do you think that evolutionary or revolutionary changes are required to the role of the DNOs to ensure that distribution networks remain fit for purpose? If the latter, in what specific areas does this apply?’

5. In the longer-term, it is clear to us that electricity distributors could well be responsible for providing services that radically transform the way that energy users interact with generators, suppliers, networks and even each other. Some of the more far-reaching possibilities are also, currently, quite far-fetched. But in the lifetime of distribution assets, such leaps of concept are most definitely conceivable – and maybe are already realistic. The challenge for the next price control period is to ensure that the UK sector sets off firmly and in the right direction; enabling short-term gains to be made and also sowing the seeds of much more significant developments in the future.

6. Accordingly, we are convinced that distributors can and should play a role in the short-term in supporting the transition to a low-carbon economy, specifically:

    - facilitating the connection of distributed generation (DG);
    - offering ‘energy efficiency’ advice focussed on network issues;

- reducing energy lost in distribution;
- reducing the carbon consumption of operational and non-operational premises; and
- reducing the carbon consumed in our operations by transport and mobile plant.

7. Each of these options is described in more detail later. In the interests of presenting realistic, practical proposals, they describe an approach that is evolutionary and, critically, consistent across subject areas and over time. We should not chop and change the approach between different issues, or our approach to any given issue.

8. Experience of research and development (R&D) expenditure since privatisation shows that an unintended consequence of RPI-X regulation is that activities that may produce benefits in the long term but are discretionary within a five-year price control horizon are squeezed out. This is why Ofgem introduced the Innovation Funding Incentive (IFI), to provide ring-fenced use-it-or-lose-it R&D funding. We judge this to have been an effective regulatory instrument.

9. To avoid a similar adverse effect on the role distributors play in supporting the transition to a low-carbon economy, similar positive incentives are required, specifically:

   - an evolution of the current IQI to provide stronger incentives to improve capital efficiency generally, and expand the scope of that incentive to cover 'sole use' and other connection costs borne directly by connecting customers. This will encourage distributors to develop measures to:
     - reduce customer demand and defer reinforcement; and
     - deploy innovative solutions[1] to reduce connection costs for all classes of customer;
   - ring-fenced funding, either through an extension of the scope of IFI, or in another mechanism akin to it for offering 'energy efficiency' advice focussed on network issues. Extension of the IFI would usefully include these behavioural and non-technical aspects in order to:
     - reinforce the incentive to reduce customer demand and defer reinforcement created by IQI reform; and
     - provide for the provision of impartial advice to Energy Services Companies (ESCos);
   - an evolution of the current DG hybrid funding mechanism to create a genuine incentive to connect DG. This would reinforce the incentive to deploy innovative solutions to reduce connection costs for DG developers created by IQI reform; and

[1] Note that this is not about the IFI. The IFI provides funding when a business need to find a novel solution has been established. The issue about sharper incentives to encourage DG connections and to reduce connection costs generally is about establishing that business need in the first place. Such incentives would also encourage the use of solutions not eligible for IFI and, critically, would encourage the release of scarce engineering resource to seek out, validate and implement novel solutions inside or outside IFI.

- application of the principles announced by DEFRA's CRC to create an incentive to reduce the carbon consumption of: major operational premises; non-operational premises; transport; and mobile plant.

DG and related incentives

10. At DPCR4, Ofgem aligned connection charging principles for generation and demand. Amongst other things, this meant that distributors had to fund part of the costs of 'shared' reinforcement. Allocation of such reinforcement costs is governed by apportionment rules laid down by Ofgem. Once distributors were required to bear part of the costs of reinforcement for DG, a price control mechanism was required to allow distributors to recover those costs.

11. Ofgem therefore introduced a hybrid funding mechanism. This is a discrete price control that seeks to recover DG costs from DG customers through discrete Generation Distribution Use of System (GDUoS) charges. It is entirely separate from the main demand price control, which creates issues that will be discussed under 'GDUoS charging' later.

12. This funding mechanism is a hybrid because income is generated in proportion to both capacity connected and investment made by distributors.

13. Although the *Initial consultation* asserts (at paragraph 2.9) that:

> '…the DG incentive was introduced to encourage DNOs to undertake the investment required to connect DG in an efficient and economic manner and to generally be more proactive in responding to connection requests',

the current hybrid funding mechanism is not an incentive. It provides only for cost recovery, and is grossly insufficient to encourage any changes in distributor behaviour. Quite properly, it places generation on the same basis as demand, in terms both of charging and cost recovery. In neither of these situations can distributors do much more than cover their costs: there is insufficient reward for distributors actively to seek to maximise connections to their systems.

14. If Ofgem wishes distributors to invest more effort and take more risk, then sharper incentives are required. Firstly, DG funding mechanism reform to create a stronger reward per MW connected would encourage distributors to:

- promote the connection of DG; and

- deploy innovative solutions to address those issues where connection costs are preventing DG schemes from going ahead.

15. Secondly, to benefit all customers in proportion, it would be appropriate to have a general incentive to deploy innovative solutions to increase capital efficiency (mostly resulting in reduced capital expenditure), particularly in sole-use and shared assets.

16. As the IQI (discussed later) acts only upon the costs borne by distributors, it has no impact upon the costs borne by customers under the approved connection charges methodologies. Something else is required to encourage distributors to reduce those shared and sole-use costs.

17. Competition in connections is not the answer to this problem, not least as shared costs are part of the issue: these are not contestable, as they involve assets deep in

distributors' systems used to serve a number of customers. The solution is also about holistic system design, protection and the policies behind both, which are similarly not affected by the choice of installation contractor. The issue is not the unit price of installing connection assets, but the choice of what assets to install in the first place.

18. This could be implemented by changing current connection charging rules to require distributors to fund a meaningful proportion (e.g. 10 per cent) of sole-use costs. Combined with the current apportionment rules for allocating shared asset costs, this would expose distributors to a meaningful proportion of total connection costs. Continuing to apply the IQI to RAV additions less pensions would then expose this proportion of total connection costs to the IQI to capital efficiency, encouraging distributors to find novel solutions to reduce all such costs.

19. The *Initial consultation* notes (at paragraph 2.18) that '[t]he RPZ incentive was introduced as part of DPCR4 to encourage DNOs to develop and demonstrate more cost effective technologies for connecting and operating generation on their distribution systems'. Specifically, RPZs provide for a £3/kW-yr premium over five years, based upon the additional DG connected, for solutions deemed sufficiently novel.

20. The *Initial consultation* (at paragraph 2.19) invites views on 'the possible extension of RPZ to include demand connections' and 'whether RPZ should be extended more widely to include innovative ways of managing the network on an ongoing basis.'

21. We support reform of the RPZ concept, including its application to demand. The benefit to customers and the risk to shareholders is about avoiding capital expenditure, which should be recognised in the parameters of the reformed scheme. If we are to encourage wider take-up, then the existing cap on the volume of projects qualifying needs to be removed. As each project submission is subject to individual scrutiny and approval, there are enough other safeguards in existence to prevent abuse of the scheme.

22. The current RPZ scheme rewards only MW of DG connected. However, the benefits come in novel techniques that avoid significant reinforcement/connection costs that would otherwise be borne by connecting customers. The risk is that the novel technique will not work, and the liability for those significant reinforcement costs would then arise in addition to the development and implementation costs of the novel solution.

23. Therefore, a scheme based upon rewarding capex avoided would be better aligned to the costs and benefits of practical schemes. For example, rather than a risk premium of £3/kW-yr, something like 5 per cent of capex deferred per year could be appropriate.

GDUoS charging

24. The *Initial consultation* notes (at paragraph 2.33) that:

> 'As part of DPCR4, a separate revenue driver was created through the DG incentive to accommodate the uncertainty associated with the future volume of DG connections. Currently DNOs are restricted to charging DG based on the revenue provided for through the DG incentive. This means that reflecting benefits of deferred reinforcement to one DG party through use of system (UoS) charges would mean that other DG would bear the cost of those negative charges (rather than demand customers who are

> ultimately the beneficiary of deferred reinforcement). We invite views on the framework of the current DG incentive'.

25. We agree that the current arrangement distorts price signals. We continue to believe that there should be a single price control for both generation and demand. The current generation price control could be reformed to become a revenue driver to the main demand control, just like the losses incentive scheme.

26. Under such a scheme, we would balance the benefits of deferred reinforcement by requiring all customers (and specifically demand customers who benefit from deferred reinforcement) to bear the cost of those negative charges. All customers would therefore face charges proportionate to their impact on the system, encouraging behaviour that minimised overall cost.

Transmission access for DG

27. The *Initial consultation* notes (at paragraphs 2.25-28) that:

> '…As the volume of DG connections continues to increase there are questions about how to manage the interface between the transmission and distribution systems most efficiently… Within the timescales of DPCR5, there may be an increasing role for the DNOs (e.g. making transmission access arrangements on behalf of a larger volume of DG) whilst some other aspects of the agent role could remain with suppliers (e.g. metering and billing for transmission charges). In the long term responsibilities of the DNOs could evolve, particularly as DNOs become involved in active network management. DNOs could become responsible for real-time management of power flows at the boundary with transmission. Developments such as these would require consideration of incentives on the DNOs and may necessitate DNOs becoming responsible for activities such as billing for transmission charges. We invite views on the range of likely developments in this area over the period of DPCR5.'

28. The key issues of rights and responsibilities need to be addressed now. We agree that some aspects of their implementation, e.g. active management of flows at the transmission/distribution boundary, may not be required within the timescales of DPCR5. However, we disagree that we need to define one set of responsibilities now and then change them later, as implied in the *Initial consultation*. This would not support building processes or electrical networks for the future.

29. We consider that the GBSO (i.e. National Grid Electricity Transmission (NGET)) should manage the transmission system and that distributors should manage their distribution systems.

30. The Balancing and Settlement Code (BSC) allows electricity companies/traders to submit offers to sell energy (by increasing generation or decreasing consumption) to the system and bids to buy energy (by decreasing generation or increasing consumption) from the system, at prices of the company's choosing. These offers and bids may be submitted in respect of each unit of generation or consumption belonging to each BSC party. The GBSO accepts offers and bids as necessary to balance the system and seeks to do so at least cost by taking the lowest-priced offers and accepting the highest-priced bids consistent with factors such as transmission system constraints and the ability of electricity companies to deliver within the timescales necessary.

31. These arrangements suggest that suppliers should remain responsible for their portfolio of contracted DG, and assist GBSO in managing transmission system constraints through submitting bids and offers. This also reduces the issue of suppliers finding themselves out of balance (i.e. with an unplanned mismatch between contracted generation and demand, which would incur penalties under the BSC) because of actions taken by distributors.

32. Taking this approach means that there is no change to the roles and responsibilities of suppliers and distributors and therefore no change to the cost base of either.

33. This leaves the issue of managing the distribution system, including the entry/exit capacity required at transmission connection sites. We consider that this is a distributor's responsibility. This is a special case of the general issue of using novel techniques to reduce reinforcement costs for generation and demand flows, discussed earlier under 'DG and related incentives'. That is, we anticipate distributors using 'active management' to reduce the need to reinforce not just the distribution system but also transmission connection sites. As noted earlier, we believe that managing the need to reinforce the deeper transmission system is a GBSO responsibility in which distributors play no part.

34. Taking this approach requires only reform of both the DG hybrid funding mechanism and the general incentive to defer reinforcement under IQI, to encourage distributors to deploy novel solutions to network management.

Non-network solutions

35. The *Initial consultation* notes (at paragraph 2.22) that:

> '…We understand that DNOs generally choose to undertake reinforcement rather than contract with DG or demand customers. Is there sufficient incentive for DNOs to consider non-network solutions before undertaking reinforcement? Are there any particular constraints on the development of demand side management and storage solutions?'

36. As discussed earlier, a general incentive to deploy innovative solutions to reduce capital expenditure however funded would, if set correctly, also further encourage the use of non-network solutions such as energy efficiency, demand-side management and the use of generation as system support.

37. The *Initial consultation* notes (at paragraph 2.23) that:

> '…It may also be appropriate to develop more clarity around how payments to generators or demand customers that defer reinforcement are treated for regulatory purposes given that they are not traditionally treated as network costs. We invite views on whether there is clarity on the current regulatory treatment of such costs and what alternative treatments might create a greater incentive on DNOs to consider contracting with generators before undertaking reinforcement'

38. As discussed later, equalising incentives between categories of costs (and treating capacity payments as network costs) would also address this potential conflict.

39. The *Initial consultation* notes (at paragraph 2.24) that:

> ‘Moves towards DNOs contracting with DG and/or storage to manage constraints may create difficulties where the DNO is part of an ownership group that includes DG and storage as, in effect, the DNO would be making payments to a related party for a service…’

40. We do not think that this difficulty means that DNOs should not be able to procure services from affiliates engaged in these activities. Rather we believe that the issue could be addressed by non-discrimination and transparency obligations placed upon the DNO. The traditional treatment of profits made by affiliates should also be reviewed to ensure that the benefits of such contracts are not removed at the following price control review. We also consider that, in some circumstances, it would be appropriate for distributors to own and operate DG and storage as part of their distribution businesses. This would be contingent upon such plant being primarily intended for system support, and not participating in the balancing mechanism.

Other DG issues

41. The *Initial consultation* notes a number of issues related to facilitating DG connections and, in the preamble to chapter 2, asks (question 3):

> ‘How do we ensure progress is made on the issues identified with the connection of DG? Should progress be facilitated through a working group or should more formal obligations be developed?’

42. The specific issues raised are:

- (at paragraph 2.12) a national standard connection agreement, possibly in the form of a schedule to the Distribution Connection and Use of System Agreement (DCUSA);
- (at paragraph 2.13) the proportionality of the connection process/requirements set out in Engineering Recommendations G59 and G75;
- (at paragraph 2.14) a standard national process for connection; and
- (at paragraphs 2.15-6) how the Long-Term Development Statement (LTDS) could be made more useful for DG.

43. Ofgem attends meetings of the key groups responsible for governing these documents, i.e. the Distribution Code Review Panel and Distribution Charges and Methods Forum. We suggest Ofgem use its influence in these forums to ensure timely resolution of these issues.

44. On the specific issue of LTDS development, we can appreciate the attractiveness of an online interactive LTDS as suggested in paragraph 2.16 of the *Initial consultation*. However, we are concerned about the practicalities of building on the work undertaken for the Department for Business Enterprise and Regulatory Reform (BERR) to develop a system that would be sufficiently robust to be of value to customers. Issues that need to be addressed include:

- the format of consistent data sets of the extra-high voltage (EHV), and potentially some of the high voltage (HV), network;
- provision of data more frequently than the annual LTDS refresh;

- agreeing a process and format of regular updates of other connection proposals/offers (having due regard to confidentiality) and authorised network development schemes, together with the associated technical data;

- developing automated modelling approaches that are consistent with internal DNO modelling processes, and apply the apportionment rules, to give a fair view of likely costs;

- agreement of who should ‘own’ and manage the information and process; and

- understanding of the degree of commitment to the connection arrangement/ price.

45. We remain to be convinced that such a facility would be used and valued by DG developers, or that it offers any material advantage over the LTDS as it currently stands.

46. Instead, we suggest that greater benefit would be realised by a more detailed analysis of opportunities for connecting DG. This would focus on those locations where DG is likely to be viable from an energy resource and planning perspective, and where the networks can most readily accommodate more DG. This approach would have the advantage of focussing the LTDS at those locations which are likely to be most helpful for developers and also those most likely to be potential candidates for a RPZ.

47. The *Initial consultation* notes (at paragraph 2.34) that:

> ‘…There remains a question of whether evolution is appropriate…or whether more radical changes to the existing framework are needed to accommodate the likely growth in DG through to 2015 and beyond’.

48. It will be clear from the preceding discussion that we support an evolutionary approach. This must be consistent across subject areas and over time. We should not chop and change our approach between different issues or our approach to any given issue. For example, consistent and strong incentives to reduce network costs whether ‘revenue’ or ‘capital’ will yield benefits in many areas. Similarly, we should define responsibilities for DG flows over the transmission system now and build from there, rather than leave the issue shrouded in uncertainty.

49. The *Initial consultation* notes (at paragraph 4.53) that:

> ‘There will be no direct link between the output of the LENS project and DNOs’ business plans. Instead, we envisage that the project will facilitate subsequent strategic thinking for the sector concerning the medium to longer term which will help inform discussions on the short term investment requirements for DPCR5.’

50. It is regrettable that Ofgem continues to resist the idea that the LENS project should not directly inform DPCR5. In our view, whether there is a revolutionary or an evolutionary approach, it is necessary to have in mind the longer term aspirations for distribution networks when formulating proposals for the next regulatory period.

51. Therefore, we submit that LENS issues such as ‘renewables-ready networks’ and also the implications of the previous debate on transmission access for DG should explicitly both inform business plans and form part of the debate on incentives that defines the

regulatory framework from April 2010. We continue to believe that LENS could and should be much more closely coupled to DPCR5.

Energy efficiency

52. The *Initial consultation* notes (at paragraph 2.41) that:

> 'The role of engaging with customers on energy efficiency is currently largely considered a role of energy suppliers. Can DNOs contribute to providing energy efficiency advice to customers? Should DNOs be incentivised to take a more proactive role with end consumers on energy efficiency, and if so how?'

and (at paragraph 2.47) that:

> '…we note that larger customers were keen to receive more advice and information from DNOs to help them improve their connection power factor. Is there more that DNOs should be doing to encourage efficient use of their network or are the current measures appropriate? For instance is there scope for DNOs to do more to educate their customers on the impact of poor power factor?'

53. Energy efficiency, in the context of DPCR5, can be considered to cover the areas of:

- generally, decisions made by customers that reduce their own carbon footprint, e.g. better insulation; and

- specifically, decisions made by customers that reduce their impact on the distribution system, e.g. power factor correction.

Decisions made by distributors to reduce system losses are addressed later in this response.

54. We continue to believe that the point made in the *Initial consultation*, that engaging with customers on energy efficiency is largely a role of energy suppliers, remains appropriate and this thereby covers the first bullet point above.

55. Nevertheless, we submit that distributors can 'contribute to providing energy efficiency advice to customers', focussed upon network-related issues, complementing rather than replacing advice provided by suppliers. This covers the second bullet point above. This could include advice on:

- peak demand lopping. System variable losses follow a square law rule, i.e. if demand doubles then variable losses quadruple. Therefore, if we can encourage customers to flatten the peaks of their demand, they can take the same energy with lower system losses. As the system is designed to meet peak current requirement (i.e. demand, real and reactive, plus losses), this exercise can also help defer reinforcement;

- power factor correction. System variable losses follow the square of the absolute current. Improving customers' power factor means they draw less current for the same useful power, so they can take the same energy with lower system losses. This point is made in the *Initial consultation* (at paragraph 2.45). As the system is designed to meet peak current requirement, this exercise can also help defer reinforcement; and

- supporting ESCos and distributed energy (DE) schemes, primarily as an extension of the provision of energy efficiency advice. It is widely recognised that the arrangements for DE schemes are so complex as to be a barrier to their development, so the provision of expert advice by a broadly neutral party must help unlock the potential of DE schemes to address climate change and fuel poverty.

56. Experience of R&D expenditure since privatisation shows that an unintended consequence of RPI-X regulation is that activities that may produce benefits in the long term but are discretionary within a five year price control horizon are squeezed out. This is why Ofgem introduced the IFI, to provide ring-fenced use-it-or-lose-it R&D funding.

57. For distributors to set up the specialist teams required to provide energy efficiency advice, appropriate incentives are required, e.g.:

- ring-fenced use-it-or-lose-it funding as for IFI;

- adaptation of the Carbon Emissions Reduction Target (CERT) so that its principles may be applied to distributors. Here, Ofgem:

  - sets targets for suppliers to take actions to reduce the carbon consumption of their customers; and

  - estimates the reduction in carbon emissions for each qualifying action in accordance with a methodology laid out in The Electricity and Gas (Carbon Emissions Reduction) Order 2008 (no. 188).

- For DPCR5, targets could be drawn up for demand, losses or carbon reduction, supported by a schedule equating specific actions (e.g. advice on power factor correction) to a contribution to the chosen measure; and/or

- significantly stronger incentives for capital efficiency. As noted earlier, some energy efficiency advice can defer reinforcement. It is self-evident that current incentives are not enough for distributors actively to give energy efficiency advice, as otherwise they would already be doing so.

58. There are economies of scale in focussing such work on larger customers who, as the *Initial consultation* notes, have requested this assistance. At the other end of the scale, power factor and high peak demand are not generally issues for domestic and small commercial connections. These customers' needs are best addressed by suppliers under CERT, which will also probably reduce overall demand.

59. We therefore recommend that the provision of energy advice by distributors be focussed on network-related issues such as power factor and peak demand for the half-hourly metered market, and particularly in areas of restricted network capacity. In addition, we submit that this service should encompass the provision of advice to ESCos and community energy schemes.

Losses and the unit driver

60. The *Initial consultation* notes (at paragraph 2.53) that:

> '…the reduction in reported losses…may be the result of actions by suppliers and cleansing of settlements data'

and (at paragraph 2.52) that:

> '…the current losses incentive…does not adequately reward actions taken by DNOs to reduce the technical losses that are within their control as these are masked by the fluctuation in commercial losses within the settlement system.'

61. Both these statements require some comment. First, in our experience the improvement in supplier data was driven by our actions in introducing charges for inaccurate or incomplete customer inventories. Some suppliers responded more readily than others to such incentives. Some took little action until we discussed with Ofgem the possibility that Ofgem might have to take enforcement action against suppliers that were not fulfilling their licence obligation to comply with the relevant industry codes and agreements. The inference that might be drawn from Ofgem's comment that some of the benefits received by DNOs under the losses incentive result from supplier activity is that DNOs are benefiting unduly from the initiatives of other participants in the sector. That would be a serious misunderstanding of what drove the improvement in the data.

62. Secondly, the fact that improvements in technical losses are masked by the fluctuations of the settlement system may be true and may have implications for the design of the incentive regime, but the fact that the benefits of technical measures to improve losses are masked by the volatility of settlements data does not in the slightest affect the strength of the incentive to reduce losses by technical means. Only a very irrational DNO management team would fail to take rewards that were available simply because, although certain, they were provided within a mechanism that masked their magnitude within the volatility of other parameter movements.

63. Thus, while we do factor the current losses incentive into our decision-making, we agree that distributors' rewards should be de-coupled from losses as reported from settlements data. We say this because we believe that the incentive to reduce technical losses needs to be enhanced (to reflect the cost of carbon) and we agree that it would be inappropriate to reward data improvements at the same rate as it is necessary to reward technical improvements. This means another mechanism is required to encourage technical loss reduction.

64. We suggest there should also remain some incentive for distributors, and perhaps also for suppliers, pro-actively to improve data quality where they can.

65. When devising a mechanism to encourage technical loss reduction, it must be recognised that:

    - networks evolve slowly. Individual assets often last more than 40 years, and their configuration can easily last twice as long; and

    - encouraging distributors to defer reinforcement will tend to increase utilisation and therefore losses.

66. This does not mean that we should not try to drive down technical losses, as all long-term programmes must start somewhere.

67. We agree that, as suggested at paragraph 2.56 of the *Initial consultation*, a modelling approach to estimating technical losses is feasible, but very complex and therefore error-prone, as well as being highly dependent upon modelling assumptions made.

68. Each distributor has power flow models used for system design, and measured load flows are used to reflect current system condition. However, such models generally:

- cover only the high voltage and extra-high voltage systems, which account for only around half the losses incurred;
- analyse demand at a point in time rather than over a year. This allows losses at peak demand to be assessed, but then requires an estimate of how losses vary from that figure across the year; and
- require a degree of estimation in any case. For example:
  - we do not monitor demand along a feeder, but rather only at the source. Our modelling therefore assumes a distribution of demand along a feeder based upon recorded maximum demands at each substation; and
  - the models attempt to reflect a large and diverse network, and inevitably involve a degree of approximation of the precise physical characteristics of individual assets.

69. While these errors are small enough for system planning purposes, if we then attempted to use this process as a year-on-year comparison, looking for single-figure percentage point changes, then what we were trying to measure would be swamped by modelling issues.

70. Taking this with the settlements issue suggests that output measures are unreliable, as total system losses can be neither measured nor modelled robustly. Alternatives include:

- some simple input measure on (e.g.) the use of low-loss transformers. The risk with such an approach is that it mandates distributors' approach to loss reduction and precludes innovative solutions; or
- an incentive linked to discrete capital investment schemes. It is simpler and more robust to model the losses impact of individual investments than of the entire system, so it should be possible to establish a mechanism that rewards loss-reducing investment decisions.

71. The *Initial consultation* notes (at paragraph 2.42) that:

> 'The current price control includes a kWh revenue driver which is designed to address cost uncertainty related to future load growth on the network. Several responses to the May 2007 DPCR5 Open Letter Consultation identified that this revenue driver is perceived to create incentives to increase the volume of sales, which runs counter to the Government's low carbon economy agenda. We agree that the kWh revenue driver may not be appropriate for DPCR5 as it places an incentive on DNOs to deliver more energy. We need to assess the cost evidence and the level of uncertainty around load growth to consider whether its weighting within the price control is still appropriate. We seek views on the extent to which a kWh revenue driver is still appropriate.'

72. The kWh revenue driver was never a particularly effective means to address cost uncertainty related to future load growth on the network. It has long been recognised that the main cost driver for reinforcement is capacity (MVA) at key points on the

system, and it has long been accepted that volumes distributed are but a poor proxy for that figure. The perception that a unit-related revenue driver is not compatible with the environmental agenda probably exaggerates the incentive properties of the current formula; nevertheless, it is a further reason to abandon the unit-related part of the revenue driver in the price control formula. At DPCR4 assumptions were made about load growth in the forthcoming regulatory period that have not materialised. The inclusion of the unit component of the revenue driver carries a risk of a mismatch between the assumptions made at the review and the outturn.

73. We therefore support removal of the kWh revenue driver. There is a range of options for its replacement, including:

- no explicit driver, relying instead upon the IQI to absorb variation in cost drivers;
- relying more heavily upon the customer-numbers revenue driver, although this is no better than the kWh driver in addressing cost uncertainty related to future load growth on the network; or
- adaptation of the DG hybrid funding mechanism, enhanced as discussed elsewhere in this response. That hybrid mechanism also seeks to fund distributors for investment that is unpredictable in both volume and unit cost.

Other carbon footprint considerations

74. The *Initial consultation* notes (at paragraphs 2.84-85) that:

> '…estimates of the carbon baseline may not be based on solid empirical evidence in some cases…it may be that the measures that are being utilised are not consistent or there might be gaps as well as issues on the allocation of emissions among businesses of the same corporate group'.

75. CE is committed to measuring and then reducing its carbon footprint. We agree there are many aspects of distributors' activities that affect its carbon footprint. We also agree that there are issues over gaps, inconsistency and allocation within corporate groups. The issues include:

- the allocation of emissions to customers (e.g. because their poor power factor increases system losses) or suppliers (e.g. because mobile generation, at least in part, displaces their purchases from fixed generation); and
- the carbon impact of investment made, such as:
    - the distance plant is brought from factory to site; or
    - the refurbish/replace decision.

76. However, 'do nothing' is not an option. We submit that DEFRA's CRC provides a framework to address some key areas of carbon footprint, i.e. own-consumption, transport and mobile plant.

77. The CRC applies to large commercial and public sector organisations, i.e. those whose annual half-hourly metered electricity use is above 6GWh. The first phase involves simple sales of allowances to businesses at a fixed price of £12/tCO_2. From 2013 there will be a Government-imposed cap on the number of allowances, and all allowances will be sold each year via an auction.

78. The scheme includes electricity, gas and other fuel types such as LPG and diesel, but excludes transport emissions. Standard emissions conversion factors are applied to convert energy use into CO_2 emissions.

79. Although CE and, we suspect, other distributors are excluded from the CRC, as are transport costs, that scheme provides a useful parallel. We believe that a simple but effective scheme could be established based upon:

- own-consumption at major operational sites[2], having fitted metering and established energy purchase contracts with suppliers. As noted in 2.54, if we remove or significantly alter the current losses incentive we shall need to account for energy consumed at these sites in some way. We submit that fitting meters to these larger sites is a suitable method;
- own-consumption at non-operational sites;
- mobile plant, measuring the product of output power and hours run if direct fuel purchase costs are unavailable; and
- all road transport, measuring mileage by class (e.g. car, light van, heavy van, wagon) if direct fuel purchase costs are unavailable.

80. With agreed factors for conversion into CO_2 emissions, an incentive rate per ton of CO_2 could then be set based upon the societal cost of carbon.

81. In each case, a scheme within the distribution price control should apply to the licensee's distribution business. Where offices are shared:

- between the distribution businesses of more than one licensee, they are recognised within the licensee by whom the majority of staff are paid; or
- with businesses other than the distribution business(es), they are recognised by a distribution licensee only if the majority of staff work within the distribution business(es).

82. We recognise that assessing the impact of mobile plant and transport presents a challenge. If nothing else, a start could be made by measuring metered energy consumed at operational and non-operational premises.

Emissions

83. On the evidence presented in the *Initial consultation* (at paragraphs 2.63-66), there is enough SF_6 on distributors' networks to merit encouragement to manage leaks. There is no obvious reason why the transmission and distribution incentive schemes should differ. We do not believe that detailed Regulatory Instructions and Guidance have been issued for this scheme. Any application to distribution must recognise the practicalities of measuring SF_6 leakage. We suggest it focus on SF_6 purchased and/or injected into plant, just as FFC leakage is measured by the volume of oil pumped into cables.

84. The *Initial consultation* also notes (at paragraphs 2.69-70) that:

[2] Perhaps any substation with an input voltage of 33kV or higher and an output voltage of 3kV or higher.

> 'During discussions on this issue at DPCR4, it was suggested that we should introduce a new mechanism on the removal of fluid-filled cables, for example with additional revenue entitlements to DNOs linked to the length of cable removed from service. Our view was that a mechanism based on length of cable removed is unlikely to be appropriate. It would not directly address the environmental concern (which relates to the risk of leakage in sensitive areas) and would be likely to give rise to perverse incentives regarding prioritisation of alternative options for managing these assets.
>
> Furthermore, at DPCR4 we considered that the level of (or reduction in) overall leakage would not necessarily be an appropriate basis for an incentive mechanism either. This was for two main reasons: first, that the environmental impact is location-specific; and, second, that volumes may be subject to significant measurement error.'

85. We agree with Ofgem that FFC incentives should focus on oil leaks into sensitive areas, not blanket replacement. Effective asset management, and the best use of customers' money, is to focus investment where it is most needed.

86. Recent representation from the Environment Agency (EA) to Energy Networks Association (ENA) delegates observed that the energy industry was considered to be 'high risk' in that it has oversight of a significant high impact low probability (HILP) environmental exposure profile. Therefore the EA advocated that the energy industry should apply a two-tier approach to discharging its environmental responsibilities. The EA position was that society would be best served by the use of regulation to drive management of key 'duty of care' environmental exposure, while risk-based incentives should be used to monitor and address (by exception) lower-order exposure.

87. We consider that fluid-filled cables and plant exhibit a HILP profile whenever sited within highly sensitive environmental locations, and therefore we agree with both the EA and Ofgem that the optimum DPCR5 framework for improving DNO stewardship of fluid-filled cables is one that finds the right balance between avoided unnecessary investment in cable assets and a step reduction in high-impact oil-leakage contamination incidents in sensitive locations.

88. We consider that this merits an incentive scheme based upon oil leaks into sensitive areas. As distributors face different degrees of exposure, the parameters of the scheme should reflect individual circumstance. For example, it may be appropriate to adapt the principles of the transmission SF_6 scheme, of setting a target leakage rate as a percentage of volume in commission. To encourage a wide range of solutions, it may be appropriate to set a baseline of the length of oil-filled cable in sensitive areas in service at 1 April 2010. Fixing the baseline would, in contrast to the SF_6 incentive, reward overlaying cables as well as minimising leaks from remaining cables.

89. Any aspirations towards a blanket replacement of fluid-filled cable assets should follow models similar to those applied to asbestos management control, where inert, passive, low-impact assets are allowed to fulfil their service life expectancy under appropriate controls which protect those who interact with the asset.

Other Environmental Issues

Visual amenity

90. The *Initial consultation* notes (at paragraph 2.73) that:

> ‘Networks have environmental impacts on the land where they are sited. These include effects on visual amenity through the intrusion of overhead lines in designated areas. Consumer research for DPCR4 showed some evidence that customers value visual amenity and are willing to pay for some improvements through their electricity bills. Ofgem subsequently introduced an allowance for network undergrounding in National Parks and Areas of Outstanding Natural Beauty (AONBs). DNOs are allowed to log up actual capital expenditure on network undergrounding in these areas’

and asks (at paragraph 2.77):

> ‘Should the scheme continue for DPCR5? Should undergrounding be fully funded by the scheme or is it appropriate for DNOs to contribute funds? Should allowances be based on a uniform proportion across all DNOs as now, or is it appropriate to allow some flexibility in these amounts depending on stakeholder buy-in and DNOs’ business plans?’

91. The fundamental questions of whether to continue the scheme, and what its scope should be, are best addressed through the stakeholder consultation process. We note only that sites of special scientific interest (SSSIs) etc. more often benefit from leaving lines overhead, as there is less disruption to the immediate environment.

92. We agree that, as for the IFI, confirmation of continued funding is required soon to maintain momentum through 2009 and 2010, and we welcome Ofgem’s intent to provide this later this year.

93. The current scheme is not sufficiently funded. The unit cost allowance does not cover the full costs of undergrounding schemes. We accept that it is reasonable to attribute an appropriate amount of the costs involved to (e.g.) the asset replacement budget, as long as this is linked to our existing selection criteria, so that we do not displace genuine asset replacement.

94. However, this split funding tends to constrain undergrounding to older lines, as noted by stakeholder groups. This is because those lines tend to be close to the top of the priority list for replacement, making it easier to make good the shortfall in the undergrounding allowance from the replacement budget. If visual amenity is to be the sole driver of undergrounding, which is what stakeholders indicate, then allowances need to be increased significantly to cover the whole cost of the scheme.

95. We should not erect new lines where existing lines have already been undergrounded. Here, we suggest that such new lines be included in the ring-fenced funding for undergrounding, less the notional cost of an overhead scheme. That cost should be attributed to the appropriate new business or reinforcement budget.

96. Overall, it is important to avoid piecemeal undergrounding of HV lines. Any length of overhead line can pick up impulses from nearby lightning strikes that can then damage short lengths of underground cable. Those cables then impose relatively long restoration times, with fault location far more cumbersome than on all-underground networks.

97. We find that the impact of our assets upon the communities we serve extends beyond visual amenity to include noise pollution. We recommend that investment to address this issue be considered alongside undergrounding in AONBs etc.

Meters

98. Distributors have obligations to provide meter asset provision service for installations prior to 31 March 2007 for legacy basic metering services under a price control. CE also provides non-legacy meters (post 31 March 2007) on a commercial basis at reasonable prices taking into account the expected asset life of the meters.

99. Promoting smart meters offers a better return to distributors if the investment case does not have to consider losses on conventional meters displaced. Further, the investment case to provide non-legacy conventional meters is fatally damaged if there is a material risk of premature replacement with new technology.

100. At a recent industry event attended by BERR, network operators, suppliers, meter operators, meter manufacturers and other parties involved in the electricity industry the issue of stranded costs was universally agreed as being one of the barriers that will need to be resolved prior to commencing any form of smart metering roll out.

101. In the current price control Ofgem provided a level of stranding protection for prepayment meters under special condition F1. This created the facility for recovery of 30% of the efficient costs incurred or likely to be incurred as a consequence of the supplier's decision to replace one prepayment meter technology with another smarter technology. Due to a high level of such activity in the distribution services area of YEDL we found it necessary to apply for stranding compensation and subsequently received increased allowances of circa £1.3m.

102. Stranding protection was given by Ofgem as part of DPCR4, as it recognised that distributors had a licence obligation to provide prepayment meters and should not therefore be expected to bear the full cost of action taken by suppliers as a result of changes in the metering market.

103. At the last price control review no stranding protection was provided for credit meters. However, given that Ofgem and BERR now hope that smart meters will be fully rolled out within the life of existing 'dumb' meters, it seems appropriate to build in a stranding compensation facility for dumb meters, whether credit or prepayment, within DPCR5 for both legacy and non-legacy meters based on the same argument provided by Ofgem in DPCR4 in relation to prepayment meters.

104. For legacy 'dumb' meters, the same principles apply as for prepayment meters with obsolete technologies. We are obliged to provide these under licence, so it would be reasonable to provide some protection when suppliers decide to supersede these assets.

105. For non-legacy dumb meters, although there is no licence obligation, meter asset providers (MAPs) will be reluctant to invest in providing meters where they expect that those assets will be replaced early and without compensation.

106. It is clear that multiple MAPs being active in the market in advance of smart meter roll-out is good for both customers and their suppliers. If distributors were to reduce their MAP activity or indeed withdraw from the market ahead of smart meter roll-out there would be fewer competitive options for suppliers. Some form of stranding protection for non-legacy meters would act as an incentive towards ensuring a stable MAP market ahead of smart meter roll-out.

107. Aside from the stranding risks, the current BERR timescales indicate that a further decision on domestic smart metering will be made towards the end of this year and

that clearly falls within the timeframe of the price control review and as such there are a number of other factors that should be considered as part of the review.

108. The current indications from the cross section of attendees at the smart metering event mentioned above was to favour either a market led or a regional franchise approach as the best approach to delivering the roll out of smart meters. If the regional franchise becomes the agreed option then clearly DNOs should be encouraged to put themselves in a position to bid for those franchises. Amongst other issues this should permit a fair return to be earned, having due regard to the stranding issue raised earlier.

109. The introduction of smart metering could lead to a wholesale review of the electricity trading arrangements if, as the Energy Retail Association (ERA) promotes, significant changes are made to the existing non-half hourly settlement processes in terms removing the arithmetic profiling of data and replacing it with almost real time data but with a significant increase in the amount of data transmitted to and from the settlement systems. Such costs are likely to fall mainly upon trading parties, but distributors will have some exposure.

110. Smart metering in the current maximum demand market could give useful information on reactive power and actual peak versus profiled peak that may inform decisions made by both distributors and customers but the case is yet to be proven that the same benefits would accrue in respect of smaller customers, i.e. domestic/small commercial. Smart metering would give DNOs better power fail monitoring which would allow us to better focus our restoration functions.

111. Smart metering *per se* will not improve our current charging models and steps such as P222 (actual consumption data provided to the network operator for each site) and statistical metering at secondary substations will give us 95 per cent of the benefits of smart meters as far as asset management and network management are concerned i.e. better information on power flows and losses. Smart metering may facilitate the functionality in future charging methodologies to have more cost reflective capacity based charging structures at lower system voltages.

112. There is the potential for smart metering to assist network operators with active network management but in order for that to work we will need to develop the following:

- high speed communications;
- a culture that accepts intervention/interruption by a third party; and
- smart appliances capable of responding to signals sent via the meter as envisaged by the ERA.

113. Many of the potential benefits of active network management such as deferring system reinforcement in respect of the domestic/small commercial market could be realised through suppliers and network operators co-operating to encourage customers to reduce their peak demand by reducing their overall consumption.

114. These potential benefits could be realised by network operators but the IT investment required to be able to use all of the data will require allowed costs to be funded through the regulatory framework.

CUSTOMERS

Customer priorities

What do customers want?

115. We welcome the encouragement given by Ofgem for DNOs to interact with their stakeholders in drawing up their forecast business plans. Building on the existing discussion and research that take place in various formats with our customers and other regional stakeholders, we are consolidating the approach into a formal stakeholder consultation aligned to the way forward indicated by Ofgem. In doing this, we are taking forward our dialogue with key stakeholders, but recognising also that other key players may have had less regular dialogue and may have less knowledge and understanding of our activities and plans. However, the primary category is customers themselves, who Ofgem's own research indicates may have little direct awareness of the key role undertaken by network operators but, as the stakeholders who ultimately have to pay for the operation of the network, have to be satisfied that they are getting a cost-effective service focusing on issues of importance to them.

116. Our strategy for consulting takes into account how best to interact with key categories of stakeholder. The first step involves issuing our consultation document covering the range of activities we undertake, current initiatives and investments in each of these areas and questions to prompt responses about priorities and balance. This document recognises that even stakeholders who have regular contact with us may have only a limited exposure to the range of activities a DNO undertakes and so it provides a basic source of information about all these activities. Key stakeholders will be offered the choice of either separate meetings to discuss issues raised by the document or attendance at regional workshops to take these issues forward. There is also the opportunity to respond in writing, either via the company web site or directly, and the existence of the consultation has been signalled for some months on the web site and by advertisement notices placed in relevant publications.

117. The responses from stakeholders will be used to develop and prioritise specific costed options for further discussion with the stakeholders in late summer 2008 with the aim of using this dialogue to assist in the finalisation of our twenty-year business plan in the autumn, ahead of submission of our full response to the Ofgem forecast business plan questionnaire in January 2009.

118. As mentioned above, such a consultation would be one-sided if it did not include a significant contribution from those who have to pay. Two factors need to be taken into account. First, it is not feasible to involve all customers, and second, the level of knowledge of most customers of DNO activities and how they are funded is low. This means that ensuring that these interactions are based on informed judgements needs careful planning and execution. We are building on the comprehensive customer survey work that Ofgem has overseen in developing our own strategy for obtaining the views of our customers through personal interviews, focus groups and telephone surveys. Following the themes indicated by Ofgem, we shall be exploring in more detail the reactions of customers in issues relating to priorities facing the business, investment options and the implications for use of system charges.

119. Finally, recognising the importance of ensuring an inclusive approach to this consultation, we shall be using the internet and the media to make customers generally aware of the existence of this consultation, thereby seeking to ensure that all who wish to do so have the opportunity to make their views known.

120. We believe that this approach will build on the work already undertaken by Ofgem; will ensure a comprehensive coverage permitting all stakeholders to make informed inputs into our planning process; and will put realistic investment options on the table with information about both costs and benefits, so that views expressed can have a real impact on the plans we submit to Ofgem early in 2009.

Current Arrangements and Development for DPCR5

Complaints

121. We operate a robust customer complaints system which sees us successfully answer complaints in an average of 4.25 days, against an internal target of 10 days. Given we are already generally performing in this manner; we are supportive of Ofgem introducing a new guaranteed standard based on an obligation to respond to complaints within 10 working days. Through consultation with key stakeholders and *energywatch* we are confident that we are suitably prepared for the implementation of the energy Ombudsman. We are already planning to operate our complaints process to ISO accreditation standard, illustrating our desire to provide our customers with the best possible level of service and one that is constantly being improved.

Quality of service – IIS

IIS in DPCR5

122. In our view the *Initial consultation* completely misses the fundamental issues associated with IIS continuing in its present form. We consider that there should be a thorough review of IIS to determine its relevance to customer needs and whether it ever has encouraged, or will continue to encourage, appropriate behaviour by the DNOs. In coming to this conclusion we have looked closely at how IIS has been working in the DPCR4 period and believe there is now sufficient evidence to demonstrate that a fundamental overhaul of the scheme is required if it is to continue into the DPCR5 period. The evidence is extremely detailed and we look forward to specific discussions with Ofgem on this matter.

123. We believe that the results from the operation of IIS in the DPCR4 period are giving clear indications that the benchmarking process used at DPCR4, by which the targets for customer interruptions (CI) and customer minutes lost (CML) were set, was fundamentally flawed.

124. CI unplanned interruption targets at DPCR4 were calculated from DNOs' own EHV and low-voltage (LV) performance plus national-average HV performance (if worse) or DNOs' own HV performance (if better). This method of determining targets means that 50 per cent of DNOs were in a potential penalty situation and the other 50 per cent neutral. CML targets were calculated from CI targets and upper-quartile restoration performance. This means that at least 75 per cent of DNOs were in a potential penalty situation. Actual IIS results from the DPCR4 period so far show no significant change from this general position.

125. There has not been a consistent and significant convergence of performance with benchmark across the industry over the last three-year period. This indicates that if the same approach is used to set targets at DPCR5, those DNOs that were seriously disadvantaged or advantaged by the benchmarking used for setting the DPCR4 CI targets will again be similarly disadvantaged or advantaged. The spread of performance relative to benchmark, particularly for HV underground circuits where a DNO's scope for intervention is very limited, indicates that the benchmarking process

does not take into account fundamental differences in how networks perform and calls into serious question the validity of the CI target-setting process.

126. In addition, the CI benchmarking process is being increasingly distorted by the level of automated switching being installed by some DNOs and by the very large volume of highly expensive unit-protected HV circuits operated by some DNOs. The costs and benefits of these interventions are not reflected in the DPCR4 benchmarking process.

127. Our concerns have become more pronounced because of the distortions and perverse incentives that are becoming apparent with the requirement to tackle many more major EHV construction projects than was the case when the benchmarks were set. Moreover, improvements in network resilience give us greater exposure to 'mini major incidents' that previously would have crossed the exemption threshold. In practice we are finding that a 75 mph wind storm that would previously have given rise to an event that would have easily passed the threshold for exemption does not necessarily do so now. This can readily add £1m to the impact of an event that has actually been well managed by the DNO. In effect, this becomes a penalty for good management of the asset.

128. A simple solution to these issues would be to greatly simplify IIS in the DPCR5 period, with targets set at current performance and a fixed incentive rate per customer hour lost or per customer hour gained. This would remove most of the current distortions and would ensure that only cost effective investments are encouraged. We believe a scheme of this form would be more relevant to customer expectations and valuations than the one currently in operation.

IIS incentive rates

129. The most important factor in determining the cost-effectiveness of any initiative to change performance is the incentive rates (value per CI or CML). The incentive properties of the scheme are not affected by the level of the targets set, and IIS going forward should recognise this position.

130. We believe it is very important that the IIS incentive rates accurately reflect customers' willingness to pay for improvements. The lack of major regional differences in the recent 'willingness to pay' survey on the value that customers apparently put on performance improvements indicates that the wide variations in incentive rates, which are a characteristic of IIS in the DPCR4 period, should not continue.

131. Remote control is a very effective way of improving restoration time and reduces what were typically 60-minute interruptions to around 10 minutes. IIS would value such improvements via the CML incentive rate. Once a critical mass of remote control has been installed, it becomes practical to develop automated switching systems that typically reduce interruption times from 10 minutes to one or two minutes. Such a change would be valued by the current IIS scheme as both CI and CML improvements. We are concerned that, though the shorter interruption time for this latter change is beneficial for customers, the current IIS valuation of such small improvements in interruption time may overstate the value that customers place on such changes. Our proposed simplifications of IIS would reduce the value of such changes and may more accurately reflect customers' valuations.

DPCR5 IIS starting point

132. There is a need to determine a DNO's starting point for the IIS target-setting process. This will require a balance between using more years to even out year-on-year random

changes and using fewer recent years to better reflect performance gains that have already been achieved. Given that most DNOs have been investing to improve performance, we consider that the balance should be more focused towards using recent years as opposed to a longer timescale. Our view is that the average of the most recent three years, as the principle used to set targets for the DPCR4 period, still seems appropriate.

Network resilience

133. There are a number of initiatives that DNOs could undertake to improve the resilience of the distribution network that in the short-term could result in an adverse effect on IIS performance. The potential for such perverse incentives to arise must be taken into account in designing an appropriate incentive scheme.

'Poorer performing' DNOs

134. At paragraph 1.31 of Appendix 7 to the *Initial consultation*, Ofgem makes reference to 'poorer performing DNOs'. We take exception to this characterisation of our performance. Ofgem is concerned that DNOs with the largest difference between actual performance and IIS targets may have been over-funded in the DPCR4 settlement. This is a misunderstanding of the purpose of the IIS scheme and the way it has worked in the DPCR4 period. If costs of improvements are above the IIS incentive rates then it would be inefficient for a DNO to incur them. The financial benefits to the DNO during the DPCR4 period of the avoided investment would have been largely offset by the resulting IIS penalty.

135. This result is much better for customers than committing them to the long-term financing of uneconomic improvements. The simplifications of IIS we propose would not require any catch-up allowances to be determined for the DPCR5 period, thus avoiding this issue altogether.

Exceptional events

136. No DNO has yet been funded to improve significantly the resilience of the network under storm conditions. Therefore it would be wrong for IIS to take storm performance into account. Altering the exemption system to ensure fewer claims can be made only increases the risk to DNOs of experiencing an adverse IIS result.

Planned interruptions

137. IIS targets should be set at a level that includes a reasonable estimate of the number of planned interruptions required to run an efficient business. However, in recognition of the uncertainty of external influences on this, it would be preferable to include flexibility in the scheme to cover material changes as a result of external influences.

Voltage quality

138. There is generally very little public concern over voltage issues as clearly demonstrated by the very low number of voltage complaints received by DNOs. We agree with Ofgem that further standards are unnecessary.

Guaranteed standards

139. The guaranteed standard governing supply restoration under normal conditions (EGS2) currently presents an unlimited exposure, on either individual claims or the

cumulative impact of a large number of claims. The highly unfortunate but nonetheless foreseeable scenario is that a fault on the system cuts power to a 132kV substation where an existing coincidental construction activity prevents restoration of supplies for a week or more. This could affect c. 50k customers representing a multi-million pounds risk.

140. The regulations themselves provide no exemption for scale, neither does the licence provide for recovery of costs above any threshold. Such unlimited exposure creates a disproportionate risk on companies that it is not practical to insure against. Therefore, we propose some cap on our exposure under EGS2, either through the regulations themselves, or permitting recovery of costs above a reasonable threshold through the price control.

141. This recovery of costs is proportionate and reasonable given the changing nature of the guaranteed standards regime in recent years. The more evident it is that a guaranteed standard has been set at a level that cannot be efficiently met in all cases, the more it becomes a mechanism by which one group of customers must pay fractionally more to enable another group of customers to be compensated because they have not received the level of service that it would be uneconomic to provide. Where the guaranteed standards have such characteristics there must be a mechanism to fund the penalty payments. This could be done *ex post*, as suggested above, or it could be done *ex ante* by including the expected level of such payments in a typical year within base price control allowances. The latter carries more risk of a mismatch between the *ex ante* allowance and the payments required in a given year. For this reason we propose the former approach.

142. EGS2 as currently constituted requires that DNOs make a payment to customers (or reduce income by an equivalent amount) if an unplanned interruption lasts for 18 hours or more during normal weather conditions. At paragraph 3.38 of the *Initial consultation* Ofgem states that:

> ‘Initial feedback from the customer research for DPCR5 is that both domestic and business customers believe the current 18 hour trigger point for the normal weather standard is too lenient. The quantitative phase of the research should provide us with clearer views on where customers would like to see this standard set. We should also have a better idea of the levels of compensation that business customers believe to be adequate and their willingness to pay to increase compensation levels.’

143. Although it is sensible for Ofgem to seek to understand the views of customers, the fact that customers may consider the 18 hour trigger point to be ‘too lenient’ is information that, in isolation, is frankly useless to a policy maker. As the last sentence of the extract recognises, what matters is the valuation that customers place on a move from one performance level to another. The cost of achieving that movement in performance has to be met by customers. There is nothing in the quantitative survey results to suggest that such a move would be valued by customers at anything like the cost of achieving that improvement in performance. Ofgem is also right to point out the perverse incentives that might arise from such a tightening of the standard. Thus, although customers would obviously value a reduction in the threshold what matters is the economics of the costs that would be involved in such a reduction and the practicalities of whether such a change is reasonably achievable by DNOs. At the present time, on average, 0.6 per cent of a DNO’s customers lose supply for over 12 hours compared with 0.1 per cent for over 18 hours. The practicalities of supply restoration within a shorter timescale, particularly in winter when the hours of daylight

are limited, has to be balanced against the perception that customers would benefit from a shorter timescale.

144. A similar situation arose when the EGS2 threshold was changed from 24 hours to 18 hours. Fortunately at that time there were two avenues open to make such a change achievable. First of all restoration staff working was moved from two-shift operation to full 24-7 availability. Secondly, cold-jointing techniques had just replaced the previous hot-jointing methods on cable systems, thereby dramatically reducing cable repair times.

145. So, whereas a change of technology and of procedures allowed a reasonably proficient operator to deliver an 18-hour standard in most cases, no such avenues are open to allow a change from 18 hours to 12 to be delivered. As such, moving EGS2 to 12 hours would result mostly in the making of additional compensation payments on a step-change basis and, without an appropriate allowance for the costs, would therefore appear to be outwith the S39A requirement for guaranteed standards to be such 'as in the Authority's opinion ought to be achieved in individual cases'. The evidence of customers' willingness to pay for such an improvement would not suggest that Ofgem should make this change.

146. We have looked at when faults that cause interruptions over 12 hours occur and this shows that most are reported in the very late evening or early in the morning and are on LV cables. Environmental (noise) restrictions mean that in most of these cases faster restoration will not be possible. We have also looked at the patterns of occurrence over the last four years and, with a mean number of faults for CE of 6.7 per day with customers experiencing interruptions lasting 12 hours or more, the standard deviation was 9.2. This indicates that there is also a 'clumping' factor involved in such interruptions, such that they tend to occur more when the restoration services are stretched by high daily fault numbers than is the case under average conditions. It is highly likely that such a pattern will be repeated across the industry. Therefore, at the margin, some improvements could be made by increasing the available number of restoration teams more towards meeting peak daily fault rate. Whether this would be cost effective in relation to the alternative of paying compensation is one of the factors that needs to be determined.

147. The finding that business customers would like higher levels of compensation is similarly unsurprising. The question is whether the generality of customers would wish to pay for the higher compensation levels that would have to be paid out even by an efficient DNO. Ofgem should also remember that the payments to business customers were never meant to be 'compensation' in the true sense of the word. The payments were a regulatory recognition that a failure had occurred. A scheme that would truly compensate businesses for the losses they may incur when there is a failure of the distribution or transmission system would have very different characteristics and would introduce very significant risks. It is more appropriate for business customers to make their own investment appraisals and invest in greater security of supply if they believe it necessary.

148. The guaranteed standard governing multiple interruptions (EGS2A), judging by the low number of claims made by customers, is proving to be a standard that customers are unaware of, or find difficult to understand or to apply. Changing this to one based on cumulative interruption time in a year would be similar in form to the current standard and would probably face the same problems with customer comprehension and application. It may be time to recognise that such a standard does not drive any significant improvement in the level of multiple interruptions seen by customers and

that an alternative way of dealing with instances of very high interruption rates needs to be found.

149. DNOs' recording systems, though not perfect, should be able to identify areas experiencing high numbers of interruptions and high cumulative time off supply, certainly for HV faults and to some extent for LV faults.

150. As seen by the reported figures in the medium-term performance report on multiple interruptions due to higher voltage faults, there are wide variations in the maximum number of interruptions seen by individual customers in different DNOs, with figures ranging from four to 20 in 2006/07. This level of variation would make it impractical to adopt a universal standard for the maximum number of interruptions seen by an individual customer either as a guaranteed standard or an 'overall' standard. Instead we would propose that such situations be covered by a similar scheme to that being applied to undergrounding. DNOs would be allowed to invest a modest amount to improve the reliability of supply in areas experiencing a high number of interruptions. The DNO would have to demonstrate that the areas concerned did experience the highest level of interruptions (for that DNO) and that the investments were reasonable in the circumstances.

Quality of telephone response

Scope of survey

151. We want to continue improving the way we interface with our customers. We would, therefore, support the view that DNOs should incorporate Ofgem's survey questions within their own surveys and recover relevant costs for this. We carry out our own market research similar to that carried out by Accent on behalf of Ofgem. Our research covers a broader range of topics relating specifically to our own operations and is used to help determine the appropriate set of actions to produce wider benefits for our customers. We believe that the most appropriate mechanism would be for all DNOs to be required to undertake a core set of survey questions which, with the exception of the current question covering speed of response, would mirror the existing set used by Accent on behalf of Ofgem. DNOs should clearly also have the choice to ask customers further questions to help understand and target wider performance improvements. This change would have the benefit that sample sizes could potentially be increased over current Accent volumes, increasing the reliability of results, and could still be subject to regular audit by Ofgem. The potential for the same customer being surveyed more than once would also be avoided.

152. Market research experts identify that customer recollection of call specifics diminishes significantly over the short term. The exception to this is that someone who has a bad experience remembers it. The positive areas are normalised. To avoid this it would be preferable for DNOs to be able to survey customers much sooner after the restoration of supplies than is currently the case. This would produce a much better satisfaction measurement, also enabling more immediate corrective action if satisfaction is reduced compared with the current reaction many weeks after an event when monthly results are published. This is the surest way of improving service.

Discretionary reward scheme

153. How we are improving communication with our customers and other key stakeholders is covered within the current discretionary reward scheme submission and we understand this scheme is set to continue into the next price control review period. We

believe that the scheme works well, as DNOs have an opportunity to share and act on best practice.

Telephony scheme – automated messaging

154. We believe that the satisfaction of customers using automated services on contact with our safety, fault and information centre needs to be established. We therefore support the extension of the survey to include those customers who reach an automated message. Potential data protection issues and some technical issues may need to be resolved in order that these customers can be surveyed.

Survey attributes

155. We believe that the current survey attributes can lead to confusion, as customers may believe that they are talking about the response of engineers in relation to restoring their supply rather than the speed of telephone answer response from our call centre agents. The removal of a speed of response question would alleviate this to a great extent without loss if it were substituted with the measured speed of response figures from call centre reporting systems.

Pilot surveys

156. If new surveys or additional questions are to be carried out, we would like to see pilot surveys carried out before any new questions are included within the incentive regime and believe that survey questions should be consistent over time.

Connections

Introduction of new standards

157. Over recent years, we have worked with Ofgem and other industry stakeholders to support the development and establishment of new standards particularly focused on the service provided to contestable connections providers, culminating in the introduction of a licence condition SLC4F that came into effect on 1 October, 2007. This has focused predominantly on a relatively small group of important customers (in the form of independent connections providers (ICPs)) and has been successfully implemented within CE. These performance standards were developed through a consultative approach involving the relevant stakeholders, including the DNOs, ICPs and Ofgem and a similar approach in developing further connections-related standards may be seen as the most effective method of developing additional or revised standards covering a broader scope of connections-related DNO activities. We adopted this approach when working closely with the public-lighting authorities (PLAs) within the distribution services area of YEDL, to establish a set of voluntary standards, placing obligations on both parties, to the mutual benefit of all involved, well in advance of the introduction of SLC4F. To facilitate this working arrangement we also ensured the establishment of a PLA steering group to review performance against agreed regional standards of service for both repairs and connections.

158. We agree with Ofgem’s proposal to review the effectiveness of the new licence condition (SLC15) and what progress DNOs have made on customer service improvements to all connections customers. We would be pleased to meet with Ofgem to share our wider performance information, and the further improvement actions we are pursuing.

159. We would welcome clarity on which customer groups Ofgem is referring to with regard to its view on the adequacy of the level of service these customers currently receive and the level of service Ofgem expects them to receive in future. This is particularly pertinent where there are ICP customers and Independent Distribution Network Operators (IDNO) customers acting as agents of the 'end-user customer' such as housing developers. We would welcome the opportunity to explore this further with Ofgem using our 2007/08 SLC4C, EGS3[3] and customer complaints information, and that of other DNOs, as the basis for discussion.

Introduction of an incentive scheme

160. Incentive-based regulation has proved to be effective in the price control framework and the introduction of an incentive scheme specifically relating to connections performance will require a thorough review and analysis of the potential framework and options that are possible in order to ensure that it benefits all customers and appropriately rewards the DNOs for outperformance.

161. In principle, we would be supportive of developing, evaluating and agreeing upon a broader incentive-based connections-related performance regime. We would be keen to consider the method by which incentives are assessed and understand what gap currently exists (if any) between our current performance levels and those likely to be set under an incentive-based framework.

162. We would also be keen to explore with Ofgem the need to introduce an effective incentive scheme if an additional (or revised) set of connections-related performance standards were developed and introduced as part of the price control review. Any incentive scheme focusing on connections activities will need to take due cognisance of the different requirements, expectations and willingness to pay for different service levels within the different groupings of customers. The nature of enquiries received and dynamics of certain enquiries are such that a one-size-fits-all approach may prove problematic to operate within an incentive-based regime. Furthermore, it is important to set a standard where the DNO has the ability to control the achievement of the standard. A standard that mandated provision of a service to a customer in a prescribed timescale where the actions of the customer could cause the DNO to be non-compliant would be perverse.

Commitment to supporting competition in connections

163. We are committed to facilitating competition in connections in line with market and Ofgem needs. We would welcome clarity from Ofgem of its expectation of what 'effective' competition in the connections market should look like in practice. We supported the need for clarity of roles and appropriate transparency in the emerging competitive market by taking our own decision to fully separate our affiliate competitive connections business operation Integrated Utility Services (IUS) from our licensed distribution business activities by March 2006 and in doing so also took the time to explain the rationale for our changes to all active market participants at the time. Since then our regular interactions with ICPs and IDNOs who are active within our licensed distribution network areas have not raised any concerns about unfair treatment relative to our affiliate.

164. Consequently, we do not accept the need for any further structural separation of DNO businesses, such as separation of DNO resource designing the contestable element of a project (when requested by a customer) from the DNO resource designing the non-

[3] The guaranteed standard governing connection estimates.

contestable element. In our view this could present more downside implications for resource efficiency, utilisation and costs than would be outweighed by any perceived additional benefits aimed at ensuring fair competition. Our 2007/08 SLC4C submission shows that our service provision to ICPs was if anything better than that provided to our affiliate, and that overall service responses within the competitive domain were generally faster than for our statutory Section 16 non-competitive enquiries. We would therefore appreciate the opportunity to discuss with Ofgem any intention for separation beyond the level that we have already implemented.

165. The impact of any proposal to separate all contestable and non-contestable activity has the potential to be significant in terms of CE organisational change, potentially including the creation of two design functions for Section 16 enquiries, one to determine the point of connection, design any reinforcement and carry out design approvals and the other to carry out the contestable part of the same Section 16 enquiry. It is hard to see how this would result in service or cost benefits to end-user customers.

166. Ofgem’s proposed approach of reviewing the effectiveness of SLC15 will assist in determining the level of compliance of all DNOs in delivering services within the standards for existing market players. If Ofgem’s wish is to see the market activity grow on a volume basis, then it is unlikely that this will be achieved through this licence obligation. The level of service provided by DNOs in response to Section 16 applications will, to some extent, influence the market share deciding to go down the contestable route. A strong, and perfectly reasonable, performance by DNOs in this activity does not necessarily lend itself to a larger proportion of customers choosing to go down the competitive path.

167. There is undoubtedly a balance to be struck here in terms of the levels of service and satisfaction that DNOs can offer in a non-discriminatory, competitive manner to all connections applicants (Section 16 or otherwise) against the desire by Ofgem to see an increased market share of connections being delivered through the contestable route. Ultimately, end-customers will make this choice, based on their experience of a combination of cost and service provided by DNOs and their competitors.

Improving customer service within the connections process

168. As indicated above, competition, although important, is not the only route to improved customer service. We are currently carrying out a major review and subsequent transformation of the connections enquiry management process to improve our service to customers from the outset and we would welcome the opportunity to update Ofgem on this over the coming months.

169. Another measure of customer satisfaction that Ofgem may wish to consider would be through the use of appropriately structured independent customer satisfaction surveys, not dissimilar in concept to the framework in place within the current IIS incentive regime associated with the telephony service. We would be willing to work with Ofgem in developing this approach further within the price control review.

Regulating the level of connection charges

170. We note Ofgem’s comments in paragraph 3.42 of the *Initial consultation* in relation to the possibility of regulating connections charges for domestic customers (and for other customers where effective competition is unlikely to develop). We would need to understand how this might work in practice before we could confirm our support for this approach. Our connections charging methodology and pricing approach are based on

recovering reasonable costs incurred in providing the connection. If there were to be some pricing 'cap' established for these customer types, we would want clarification as to how all reasonable costs incurred would be recovered if they were not to be fully recovered directly from the customers requesting the connection.

NETWORKS

Network cost assessment

171. Benchmarking can help to inform a price control review provided *all* of the following criteria are met:

- the data on which the benchmarking is based is truly comparable;
- the firms that have the lowest or the lower costs must be worthy of emulation (bearing in mind that lowest cost is not necessarily best); and
- the specification of the benchmarking model must accurately capture the factors that drive the costs that are the subject of the analysis.

172. No benchmarking exercise carried out by Ofgem for the DNO sector has ever satisfied these criteria.

173. We believe the key lessons have been captured in the objectives set out by Ofgem for cost and outputs work. These are to:

- improve the incentives faced by DNOs to make efficient investment;
- remove distortions in the current control;
- increase the capacity for the price control to reflect the specific business needs, strategies and objectives of each DNO; and
- make best use of the data collected through the annual regulatory reporting packs (RRPs).

174. At this stage though we have concerns about the direction in which the cost assessment work is being planned to be taken to achieve these objectives.

175. Our thoughts on improving investment incentives are set out in the section below on capex incentives.

176. We believe there is merit in looking at removing distortions on incentives by simplifying the RAV treatment for different categories of costs provided due attention is paid to the ability to finance our future obligations.

177. We support the building block approach to forecasting and building in our own business and stakeholder requirements. We believe the building blocks should be adequately defined and should also allow for judgement in forecasting. These forecasts should be tested against the DNO's own assumptions and performance by utilising the improved RRP data along with information gathered during the annual visits to facilitate the assessment of the individual DNO's performance.

178. We welcome Ofgem's declared intent to allow DNOs to propose business plans that match their own view of the future and reflect the concerns and priorities of their stakeholders. However, we are unsure how such plans can be assessed against, for example, Ofgem's consultants' benchmarks for the purposes of IQI. If the DNO is free to choose its own outputs, any assessment of the reasonableness of the expenditure projections will have to be made with this in mind. We are unsure whether Ofgem's consultants will be able to advise on such a flexible basis. Ofgem should also clarify that the IQI mechanism will operate by comparing outturn with the detailed forecast business plan questionnaire to be submitted in January 2009.

179. Our concerns centre around Ofgem's signal that it not only wishes to continue to undertake efficiency analysis at DPCR5 but that this analysis should be more extensive than at earlier reviews. In particular, it has indicated that it wishes to explore:

- benchmarking on a more disaggregated dataset;
- the definition of appropriate cost drivers for the purposes of efficiency analysis;
- alternative techniques such as data envelope analysis (DEA);
- interactions between network activities; and
- international benchmarking.

180. We have some comments about each of these items but prior to looking at the detail we would make the following comments about whether the scoped work meets the overall objective.

181. This programme of work is more extensive than in previous reviews, but before embarking upon it, we need to consider the appropriate scope for an efficiency review of a group of network operators that is largely under private ownership and that has been exposed to incentive-based regulation since 1990.

182. At the time of privatisation, it was recognised that the industry was significantly inefficient. At each price control Ofgem established and reiterated the incentive regime applied to the DNOs that could be expected to encourage those businesses to operate more efficiently. However, Ofgem also took a view on how much efficiency the operators could achieve, and reflected these estimates in the price control settlements in order that customers could receive the benefits of *expected* efficiency savings within the price control period, rather than at the end after they had been revealed.

183. Ofgem identified two sources of efficiency saving: those that individual DNOs could be expected to achieve if they were able to operate at the frontier of best practice defined by leading operators in the sector; and those that the sector as a whole could achieve since it was unlikely that even the leading operators were completely efficient, and simply represented the best in a relatively inefficient sector. The first of these was reflected in the price control determination through the efficiency analysis, and the second by the productivity analysis.

184. The original concept behind RPI-X regulation was that companies would reveal efficiencies and would be rewarded for this revelation such that customers would, after a lag, enjoy the benefit in the price controls that followed. Ofgem then adapted this concept in distribution price controls by anticipating a degree of future efficiency outperformance prior to it being revealed. This element of anticipation was arguably appropriate at that time due to the starting point and the scale of efficiencies

envisaged. However, after nearly 20 years, we should return to the purer RPI-X implementation, where the RPI component is recognised to include productivity improvement, and a planned shifting efficiency frontier is inappropriate.

185. The key questions in determining the scope of efficiency work at DPCR5 are therefore after 18 years of incentive-based regulation:

- is there any reason to expect there to be a systematic difference between DNOs' levels of efficiency? And
- is there any reason to expect the trend for real unit operating expenditure (RUOE) for the sector to be systematically different to the rest of the economy?

186. If there are efficiency-based reasons for answering in the affirmative to either of these questions, then this should surely give Ofgem reason to pause for thought to consider how such an outcome could have materialised.

187. As far as the first question is concerned, the purpose of incentive-based regulation applied to date is that all DNOs have been exposed to the same marginal incentives to improve efficiency. If operators have not, over the past 18 years, arrived at the point where their efficiencies are broadly comparable, this points to a relative managerial failure that has not been corrected by successive shareholders despite many changes of corporate control. In other words, there has also been a failure of corporate control. Is there any reason to believe that this is the case?

188. It is quite likely that at any individual point in time, efficiency will be different across the DNOs, but the key question is the extent to which these are systematic or transitional differences. These should not be systematic, if the markets for corporate control and management are working effectively, and the regulatory regime is working as intended.

189. As far as the second question is concerned, the productivity target applied to the sector is captured by the RUOE target. The economic effect of a target that is greater than zero (i.e. that requires the business to achieve reductions in its RUOE) is to reduce the payments made to the owners of the inputs used by regulated businesses, relative to the rest of the economy. In the regulated sector, if a productivity target of 2 per cent has been imposed, then the benefits of achieving productivity of 2 per cent go to customers, not to the owners of the inputs. In the competitive economy, in contrast, the achieved productivity is reflected in the prices paid for the inputs. This is because if the business systematically paid input owners more than their productivity, its cost base would rise and prices would need to rise, which would not be sustainable for the business operating in a competitive market. On the other hand, if it systematically paid the owners of inputs less than their productivity, then those input owners would find it worthwhile to offer their inputs elsewhere.

190. In the longer term, there are risks with persisting with a productivity target that enables customers to capture the benefits of productivity rather than the input provider who achieves the productivity. In short, the regulator is in danger of violating the input provider's so-called 'participation constraint', incentivising labour and capital to move out of the regulated sector and into the rest of the economy where rewards relative to productivity are greater. In our industry where we are looking to increase outputs these risks have a higher likelihood of materialising.

191. Of course, as we have seen, real cost reduction targets may be sustainable for a relatively long period of time. For example, if there is general inefficiency in a sector after privatisation, then regulators can not only impose efficiency targets estimated

through benchmarking, but also general real cost reduction targets across the industry. In this case, the achieved productivity simply represents the catch-up to the point where the businesses should have been operating. But it is now generally recognised that this pre-privatisation slack has been removed, and this is evidenced by overspending against opex allowances, so that the arguments in favour of firm-specific and sector-wide real cost reduction targets are much less compelling.

192. In the light of these arguments, Ofgem may wish to consider whether the evidence base available to it at DPCR5 will be sufficiently robust to determine *ex ante* RUOE reductions, or whether it should instead rely on the incentive power of the fixed-price, five-year price control regime to encourage businesses to continue to innovate and seek out improvements, recognising that these are much harder to obtain than in the past.

193. Even if Ofgem considers it appropriate to undertake some benchmarking, these arguments call into question the suitability of the broad and deep scope proposed by Ofgem in the *Initial consultation*. A lengthy and resource-intensive process is unlikely to be proportionate to the scale of the efficiency savings that Ofgem or its advisors are able to detect from the data with any degree of reliability.

194. Furthermore, our arguments also suggest the need for Ofgem to develop a conservative set of criteria to convert the empirical findings into RUOE targets in order to avoid running the risk that expenditure levels are set too low. This is especially relevant given that all the DNOs are currently overspending the opex allowances set in DPCR4.

195. In terms of the detailed approach to benchmarking, we do not support disaggregated benchmarking for the following reasons:

- outstanding issues relating to the categorisation of expenditure;
- the possibility of substitution limits comparability;
- it will neutralise or negate individual assessments in setting our allowances, and not recognise the trade-offs between categories;
- inadequate ring-fencing across expenditure categories renders results meaningless; and
- benchmarking potentially creates incentives to load costs in some categories relative to others (e.g. a re-run of the capitalisation problem).

Each of these is dealt with in more detail below.

196. We note that Ofgem recognises that there are a number of outstanding items to resolve and we have concerns that, if these have been unable to be resolved to date then they will not be resolved in an appropriate and timely manner for this price control review.

197. Indeed, if Ofgem continues to go down the efficiency analysis route, we would welcome further discussion on cost normalisation as we note one of Ofgem’s proposals is to adjust for labour rates. We observe that any adjustment of this kind introduces the difficulty that firms have optimised their costs taking into account the labour markets in which they operate. Labour costs must be presumed to have influenced, at the margin, decisions on whether to apply an operating- or a capital-cost

solution to a particular problem. Even if Ofgem were to normalise for different wage rates, how would it adjust for the substitution effect? Furthermore, even if there is a differential in wage rates across the country, this is one of several 'special factors' that will apply differently to each DNO. We would be concerned about any approach that singled out one such special factor whilst leaving another without recognition. In practice we think that the better approach is to make a specific adjustment to the allowed costs where there is clear evidence that a licensee suffers, unavoidably, from high costs associated with its unique circumstances.

198. We agree that one of the key issues at the last (and previous) reviews was the difficulties that arose with respect to the attribution of costs between the operating and capital cost categories. Some of the inconsistencies have been resolved with the introduction of the annual RRP and may further be addressed by a building block approach, for example, in relation to faults/maintenance versus non-load related expenditure (NLRE).

199. However there are, and will remain, valid differences in the allocation of costs that are driven purely by different geography, company structures, policies and sourcing decisions e.g. lease or buy buildings or transport. This should not be an issue for Ofgem if DNOs can demonstrate that costs are efficiently incurred. There is evidence from the recent labour survey that significant differences remain due to both the interpretation and the application of the RRP rules. We would be cautious about accepting cost assessment and comparisons that are carried out at a disaggregated level as this can only be achieved if the data is robust.

200. Taking the above into account, it is difficult to see why further drilling of comparative costs at a more disaggregated level is going to provide benefits that outweigh the further work necessary to ensure that the data sets are consistent at this lower level and that assessments recognise trade-offs between the categories.

201. There are other preconditions for the proper use of benchmarking that require significant effort to enable meaningful results to be drawn. There must be proper recognition of:

- different operating conditions. As well as different ’normal’ operating conditions there may be transitional or unique conditions in one company at a point in time, either high or low. These outliers need proper investigation and a rational explanation provided to all parties;

- differing quality outputs. Least cost is not necessarily the most desirable outcome and there is a trade off between cost and the level of quality of service; and

- differing risk profiles. Each DNO makes a choice of the risk it wishes to bear.

202. All these factors are evident in a competitive market and efficiency analysis reveals that there are companies in these markets that survive and make an average market return despite having costs that at any given moment in time are above those of the frontier that is defined by short-run behaviour. Companies are making choices in the above categories and the most enduring successful companies tend to be those that plan for a sustainable long term. Put simply frontier performance may not be the desired outcome.

203. On the final point of international benchmarking we believe in principle that benchmarking *could* be improved by the use of international data. Before embarking

on this course, Ofgem would need to be clear what light the cost performance of a company operating in a different economic and commercial environment in a different part of the world would shed on the cost performance of a DNO operating in Great Britain. Moreover, we have concerns that data will not be cleansed sufficiently to ensure its comparability to the DNOs operating in Great Britain.

204. The *Initial consultation* notes (at paragraph 4.71):

> ‘We will seek…to reduce accounting distortions, encourage beneficial trade-offs and remove artificial boundary issues such as those impacting on RAV calculations during DPCR4’

205. We agree that the trade-off between capex, opex and performance is a key area to develop. It is also essential that we understand the nature of trade-offs. For example, some companies have inherited legacies of high-reliability high-cost unit-protected systems; others have invested heavily more recently in overhead line (OHL) rebuild (some with covered conductor) or in switchgear replacement with remote control. All these improve performance, but at a cost.

206. The DPCR4 methodology did not illuminate those issues, as it took each area separately. Asset-rich companies will tend to have past investment fully funded, including renewal and reinforcement of existing systems, as capex modelling simply replicates existing network architectures. There was no recognition of anything but the cruder aspects of network architecture in setting IIS targets, so those licensees that have been more prudent in their investments will not be adequately funded to close the performance gap.

207. Of course, the current turbulent input price inflation situation accentuates the need to be wary of using historical benchmarks to set future allowances. Combined with the recognised standard pitfalls of using comparative benchmarks, this makes the selection of an appropriate process at DPCR5 vitally important.

Costs and delivery

Capex incentives

208. The *Initial consultation* notes (at paragraph 4.6) that:

> ‘The companies are incentivised to realise capex efficiencies by allowing them to keep a proportion of any cost savings from spending less than the capex allowance over a five year period (and vice versa), regardless of when in the five year period this occurred. In addition DPCR4 incorporated an IQI to encourage more realistic forecasts from the companies. It does this in two ways - by giving additional income to DNOs who forecast spend close to our assessment and by providing these DNOs with a higher incentive rate than those DNOs with higher capex forecasts, thereby increasing their rewards for outperformance.’

209. This incentive mechanism was developed for the recent gas distribution price control review, building upon the sliding scale mechanism (SSM) developed at DPCR4. As the *Initial consultation* notes, it has two elements, specifically:

- an up-front incentive to accuracy in forecasting. Companies’ forecasts are compared to a baseline informed by engineering consultants’ analysis. There is an explicit reward for those companies closest to the benchmark; and

- an ongoing incentive to capex efficiency. The rate is set by the same process as the up-front reward for accurate forecasting, so those companies closest to the benchmark receive the highest rate of retention of the benefits of underspend. This is realised through the capex rolling incentive, which smoothes that retention regardless of the timing of any efficiencies.

210. We support continued use of the IQI to encourage both up-front honesty/accuracy in forecasting and ongoing efficiency in delivery. Experience of the scheme suggests some modest reforms to ensure that the companies are encouraged:

- to tell the truth at the price control review; and

- make the right investments efficiently.

211. The calibration of the rewards offered by the IQI at DPCR4 did not take account of risk aversion in the industry. Managers of some DNOs could have used high forecasts in order to insure themselves against the possibility of cost overruns, to the detriment of customers and the regulatory system. Ofgem appears to agree, noting (at paragraph 4.24 of the *Initial consultation*) that 'the evidence on capex, for example actual expenditure to date relative to the forecasts made at DPCR4, suggests that DNOs may still have an incentive to over-forecast'.

212. Under the calibration of the IQI at DPCR4, the reward for realistic forecasting, and therefore the cost associated with unrealistically high forecasts, was modest (for any given level of outturn investment spend). At the same time, unrealistically high forecasts led companies to be exposed to a much lower marginal incentive rate on capex overspends and underspends. This has the effect of making revenue streams more predictable, and essentially offers insurance for managers against the inherent uncertainty in investment requirements.

213. Since this insurance was relatively cheap under the calibration of the IQI at DPCR4 – little profit was foregone by moving one 'column' to the right - it would be entirely rational for risk-averse managers to submit an unrealistically high forecast. The low cost of this insurance means that such behaviour could go unnoticed by shareholders, meaning that managers were not constrained from accessing it for their own reasons

214. Ofgem should recalibrate the IQI matrix in order to make the submission of lower forecasts relatively more rewarding. The intuition requires little explanation. Risk-averse companies require a greater reward than Ofgem provided at DPCR4 in order to submit a forecast that will result in their facing a higher-powered incentive regime, where overspend relative to allowances is more possible. If such a recalibration were introduced, the overall effect would be to provide a strong incentive for forecasting in line with expectation, rather than submitting forecasts biased upwards as a result of risk aversion.

215. As part of this recalibration, we submit that Ofgem should introduce asymmetric exposure to underspend and overspend, in particular for companies with a proven track record of truthful forecasting. This would provide such companies with strong incentives to make efficiency improvements, but would afford them greater protection from the risk of cost overruns – a risk they choose to bear by submitting a low forecast. In line with the principle described above, this would better reward low-forecasting companies and would encourage more companies to submit lower forecasts at DPCR5. CE believes that such a calibration would be of direct benefit to customers in both the short run and the long run.

216. As noted a number of times elsewhere in this document, a sharper incentive to capex efficiency has a number of knock-on benefits in encouraging distributors to seek out unconventional solutions to defer reinforcement and reduce connections costs.

217. The *Initial consultation* also notes: (at paragraph 4.79) that:

> 'The application of the IQI approach requires a baseline level of costs to be determined against which the DNOs' forecasts are compared. This could be based on historical costs, Ofgem modelling or benchmarking or a combination. The determination of such baselines may be more practical for certain areas of costs such as non-load related capex and load related reinforcement. It may be more difficult for additional areas of spend such as network resilience or flooding where there may be more uncertainty over levels of expenditure. As such, it may be appropriate to base the IQI on a certain number of building blocks but apply the results in terms of strength of incentives to all areas of costs. As we are seeking to better integrate incentives across different areas of costs it may be appropriate to apply the IQI more widely, for example to network operating costs and engineering overheads. We would welcome views on the scope of the application of the IQI'.

218. We agree that it would be pragmatic to carry out the initial comparison of forecast to baseline on a reduced set of costs where such comparison would be most robust. We also support moves to remove perverse incentives between arbitrary cost classifications, which continue to distort decision-making. Writing more costs to the rate base, as Ofgem proposes in paragraph 4.75 of the *Initial consultation*, is one way to do this. This would be consistent with applying the incentive to ongoing efficiency within the IQI to all network costs. A consequence of slowing these cash flows is that the commensurate higher risk must be reflected in the cost of capital.

219. It is not entirely clear to us what Ofgem means (at paragraph 4.80 of the *Initial consultation*) by distributors 'commit[ting] to a wider package of outputs', particularly in the context of the threat of clawback of unspent 'allowances' within that paragraph. It can be argued that there are three classes of outputs, specifically:

- significant investment linked directly to significant output and susceptible to an explicit price control mechanism, e.g. quality of service (QoS);
- significant investment not linked to an explicit price control mechanism but sufficiently quantifiable to be subject to clawback, e.g. base-case replacement/reinforcement; and
- 'balanced scorecard' outputs that do not require significant incremental investment (so clawback would be inappropriate) but reflect good all-round performance.

220. We therefore commend a combination of:

- explicit incentive mechanism where measures are directly linked to investment;
- scrutiny of key outputs that underpin the cost assumptions of the periodic review settlement, e.g. asset serviceability metrics, with the threat of clawback; and

- a balanced scorecard with some incentive (perhaps a discretionary award) to reflect good all-round performance that does not fit well in the two preceding categories.

Input prices

221. One of the defining experiences of the DPCR4 period has been the global demand for raw materials and finished products driving prices significantly above-RPI. In DPCR5 we believe that there is a strong argument to support Ofgem assessing price rises in a radically different manner to that undertaken at DPCR4.

222. The approach at DPCR4 appears to have been an overall assumption that the DNOs would experience price rises in line with RPI-measured inflation. However, to the extent that most of the goods purchased by UK households are manufactured overseas, the average level of input price inflation embedded in the RPI basket is affected quite considerably by the very benign wage conditions enjoyed by firms that locate in less developed countries. To expect electricity DNOs with a UK-based workforce to see the same input price inflation as the average firm supplying goods and services to UK households hardly seems credible.

223. Therefore for DPCR5 we advocate identifying the input mix that can be found within DNOs' opex and capex, investigating the price trends affecting each individual input in order to forecast input price growth for each input, and then aggregating the individual estimates into overall measures of input price inflation.

224. Unlike in previous price controls the expected increase in input costs cannot expect to be offset by any productivity gains in the sector that exceed those of the economy generally.

225. Separately, we note the allowances Ofgem granted to the gas distributors, and it is essential that the upward cost pressures in electricity distribution are fully recognised. We have engaged, through the ENA, consultants to provide an independent view of the issue and expect to factor these views into our forecasts.

Delivery

226. We are confident that we will have plans in place to ensure adequate internal capability and/or contract coverage to meet the delivery requirements of our forward plan.

227. We advise that now is an appropriate time to allow additional funding to facilitate workforce renewal (recruitment and training) as this is a significant cost that is not immediately productive in terms of units of work output. This is a good candidate for some form of IFI style ring-fenced expenditure as described previously.

FINANCIAL ISSUES

Cost of capital

228. The setting of an appropriate cost of capital is always an essential element of any price control review. As we approach DPCR5, the need to properly compensate shareholders through the cost of capital for the risks that they face is as important as it has ever been. The scope to outperform other aspects of the price control settlement has been shown by the experience of the DPCR4 period to have been significantly

reduced, if not eliminated. In addition the outlook for the sector is such that the past is not necessarily a good guide to the risks that the future might hold.

229. In terms of method, we are supportive of maintaining the traditional approach to the cost of capital with any incentive mechanisms being separately constructed.

230. We appreciate that there is a degree of circularity in that the cost of capital must reflect the degree of risk being borne by the business and therefore the finalisation of the cost of capital comes later in the process. We do have concerns that Ofgem's timetable seems to provide only one opportunity for consultation on the cost of capital and that is after the publication of the initial proposals. The proposed December 2008 'Policy Paper' will include 'thoughts for how to calculate WACC' but an evaluation of those thoughts will not appear until the June/July 2009 paper. The current absence of the September update from the DPCR5 timetable restricts the opportunity for Ofgem to declare formally its intent. We therefore consider that the June 2009 initial proposals should set out a detailed rationale and 'minded' value of the cost of capital with the caveat that it could vary depending on changes in the risk profile after that date. We would also expect Ofgem to be able to update us on its thinking during the bilateral meetings and workshops that will take place between June 2009 and November 2009.

231. We believe that a simple interpretation of recent RAV premia in recent transactions providing a view of the 'real' cost of capital is misleading. Our thoughts on this subject are contained in the regulatory asset value sub-section that follows.

232. Of particular importance for the overall perception of regulation, and hence regulatory risk, is the consistency applied between successive reviews. The long-term nature of the assets, and therefore the long-term expectations of investors, should be matched by a long-term view of the cost of capital. It is inappropriate for the allowance to fluctuate significantly from one review to another, or from one regulated sector to another. Such volatility is likely to be counter-productive in the long-term as the historical trend of settlements will ultimately be factored into the future returns required by investors. With long-term investment needed in the sector, the cost of capital needs to provide a long-term incentive to invest and this will only be the case if it demonstrates stability.

Approach to cost of capital

Indexation	The existing process of having a complete resetting of debt interest rates every five years is already at odds with the commercial drive to match assets and liabilities. A non-regulated business, in an asset-driven sector, would look to a significant degree of long-term financing as a means of risk reduction. Market conditions prevailing at the time of issuing debt will influence the maturity of the offering as well as driving the coupon. The decision on whether the debt is index-linked will be based on an assessment of the whole-life economic costs. A move to some form of indexation (even putting aside the inherent difficulty in composing such an adjustment) exacerbates the mismatch by bringing in a form of continuous reassessment. Given that the rate is applied to all debt (or at least Ofgem's assessment of the debt level) this is the equivalent of a long-term business being funded on a short-term basis. The banking sector has recent experience that this model

appears to work in times of plenty but fails spectacularly in times of stress.

Triggers

This is the same concept as indexation but represents a coarser tool as the reaction is based on step changes rather than attempting a smooth correlation. We therefore consider that it is as flawed as the indexation approach. Certainly we do not consider that any of the recent transactions can be used to suggest that such a mechanism is now appropriate.

Embedded debt

As discussed above, we consider that the cost of capital debate should reflect a commercial position and therefore the cost of embedded debt (provided it meets some efficiency test) should be recovered through the cost of capital. In effect customers are committing to pay for the historical RAV additions and the financing costs incurred between the time the costs are incurred and the subsequent recovery from customers.

Whilst Ofgem included a small allowance (0.4 per cent) in the DPCR3 settlement this was removed in the consideration of the DPCR4 settlement. Of course DPCR4 was finalised during a period of falling rates so the overall pressure was for a lower, i.e. future, rate. However, the failure to recognise embedded debt explicitly at DPCR4 was offset by the decision to take a longer term view of debt interest rates.

This issue has to be considered as part of a review that would see a consistent application irrespective of the current trend in rates. It is inappropriate to bring this into the equation merely as a result of a market change where recently acquired embedded debt might be at rates that are below the current or projected market rates.

Split cost of capital

We recognise that the expenditure that has ‘yet to be accepted’ into RAV carries with it a greater degree of risk than ‘accepted’ expenditure. If this were a significant element, then it would be appropriate that a higher rate of return should be earned during the period of uncertainty. We do not consider that there is a significant amount at issue here and therefore we do not see any benefit in trying to complicate the present process.

Equity injections

It would be a function of any period of rising RAVs that the increase in RAV is funded by a combination of debt and equity. This is the only way in which gearing can be maintained at an appropriate rate.

Additional debt could be used to reduce the demand on equity but the tax benefits are returned to customers. In addition any decision on higher gearing would have to be considered in the context of whether this would have a negative effect on the credit rating especially the risk of a downgrade below investment grade.

Any equity injection can only come from lower dividends or issuing new shares.

Provided the cost of capital reflects the appropriate rates needed to attract investors, and any associated issue costs, then the mix of equity and debt funds should be available.

What is particularly important is to ensure that Ofgem does not use equity as the ‘easy’ option to solve financeability issues. In a scenario where the financial ratios are under stress, as a result of the cost of capital or operating allowances being too low, or a lengthening of RAV life, it is not acceptable to consider that these shortcomings should be resolved by shareholders having to forgo dividends or inject further equity funds both of which would have the effect of even further dilution of their eventual return.

233. The discussion of the two issues of indexation and triggers, seems to imply that they would be applied to the whole of the debt assumed by Ofgem. The practical issues are significant and at the most it would only be worth considering these issues more favourably if they were applied only to the incremental debt that has to be raised over the DPCR5 period as a result of RAV growth or refinancing of existing debt. However, this would have to be undertaken in tandem with an acceptance of the existence of embedded debt and an appropriate level of funding.

234. The problems of indexation are further illustrated by the recent conclusions of the Office of Railway Regulation (ORR), the Civil Aviation Authority (CAA) and the Competition Commission (CC) who were all unconvinced that such a step was practicable. Ofwat echoed this as well as expressing concerns that there was a mismatch between the benefits and risks attributable to customers.

235. Ofgem needs also to give further consideration to the assumption of what proportion of debt is deemed to be index-linked. As discussed above the normal commercial evaluation at the time of issuing debt may conclude that debt with a nominal coupon has a lower life-time cost than the equivalent index-linked offering. Certainly CE’s experience in raising its most recent debt (albeit in May 2005) was that the all-in cost of nominal debt was lower than the equivalent index-linked offering. Since that time the increases in the RPI have reinforced the efficiency of selecting the nominal debt in preference to index-linked. It seems inappropriate if Ofgem’s assumptions over the cost of capital should drive a DNO to the opposite answer.

236. An inappropriate assumption that debt is index-linked reduces the overall cash generated in the DPCR5 period. This creates timing issues in those circumstances where, for valid long-term commercial reasons, nominal debt was raised.

Financeability and financial modelling

237. We consider that it is essential that Ofgem commits to providing an appropriate cost of capital over the regulatory lives of the assets.

238. It is important that the overall financial settlement for the DPCR5 period is reached without compromising the future financial position. Problems relating to cash flows in the DPCR5 period cannot be solved by robbing the DPCR6 period etc., nor should the opposite be applied. Cash flows are cyclical and are particularly sensitive to the investment needs of the business. In times of high investment both equity and debt will be increasing, whilst periods of lower investment should allow both debt and equity to be withdrawn. It is important that this latter scenario is not misinterpreted as being an ‘easier’ period that could then lead to the suggestion that the improvement in the overall cash flow should be deferred to cover potential ‘harder’ times in the future.

Prudent management may decide to factor that into their plans but that is a decision for them and not the regulator.

Financeability adjustments

239. Financeability adjustments are an admission that the settlement being proposed, as measured during the next regulatory period, is flawed.

240. Provided that the overall package reflects appropriate assumptions on the level of achievable costs, the timing of cash flows and the cost of capital, there should not be any need for a financeability adjustment to be made in respect of any DNO.

241. Theoretically financeability adjustments would be expected to be NPV-neutral as they are merely a way of giving shareholders their own money but over a different time horizon. However, given that the need arises only because of other shortcomings in the proposed settlement, there is a strong argument that they reflect an understatement of the allowances that are needed, which indicates that the adjustment has to be NPV-positive.

242. There may be circumstances where the negative impact on the financial position results from errors in the previous settlement which gave rise to underfunding in the past. In that case it would be appropriate that an adjustment be made and as such it would have to be NPV-positive, although this should then be considered as an error correction rather than a financeability adjustment.

Depreciation

243. There is a history of changing the depreciation profile as a means of solving cash flow problems as they were envisaged at previous reviews. Similarly the mix of expenditure classified as ‘opex’ or ‘RAV additions’ has cash flow implications.

244. The discussion over regulatory asset lives is twofold. Starting with ‘agreement’ over the level of the allowed cash outflows, the first decision involves allocating to one of two pots. The customer pays for one of these, the ‘opex’ pot, in full during the regulatory period but only pays a deposit on the second, the ‘RAV additions’, pot. The balance becomes an IOU which is carried forward to be satisfied in instalments by future customers. Debate on the size of the deposit and the timing of the future instalments has to go hand-in-hand with the debate about the initial allocation across the two pots.

245. Any deferral of recovery of expenditure, whether as a result of increased additions to RAV or an extension of regulatory lives, would have to be accompanied by a compensating increase in the cost of capital. This would especially be the case if the deferred recovery came about because of the perception that the overall finances had improved. As well as reflecting additional regulatory intervention risk, the shareholders would also have a higher risk that the deferred income would ultimately be subjected to further deferment as well as potentially being rewarded at a lower cost of capital.

246. Assumptions used for setting regulatory allowances diverge in a number of areas from the accounting treatment. Any comparison of accounting asset lives and regulatory depreciation would also have to take account of the differences between accounting capitalisation rules and Ofgem’s definitions of what constitutes RAV additions. The accounting policies of each DNO will be set in the context of these differences and it is therefore for the DNO to ensure that the net asset value in the statutory, and

regulatory, accounts is supported by the underlying worth. If not then accounting impairment charges will become necessary.

Financial modelling

247. We understand Ofgem's desire to publish its detailed models but we have reservations regarding the usefulness to third parties of providing a model that represents only Ofgem's view of the costs and income.

248. In any event should publication be preferred then we would only support this approach if the extent of the data being published were consistent for all DNOs.

Profiling

249. The profile of allowed income can be a significant issue at the junction of two reviews, particularly where there is an upward movement required in allowed income. Taking this into account, it would appear appropriate to have a smooth trend (whether up, down or flat) of allowed income within a regulatory period to provide stability to customers, recognising that the distribution element in end-user prices is relatively small and the proportion is likely to continue to decline given other market conditions.

250. Provided the profile is incorporated in the setting of the allowed income, the result will be NPV-neutral within the regulatory period.

251. Within this overall position one area that does need to be considered relates to credit and bond metrics. As part of the modelling, credit ratios for each year need to be calculated. Additionally, there is a need to check compliance with any bond covenants at the individual DNO level for each year and not just by reference to an average position over the five years. To the extent that significant issues are apparent then the profile should be amended, whilst maintaining the overall NPV for the five years.

252. From an accounting perspective there can be oscillations in profit but this has always been the case as accounting and regulatory treatment of costs are not the same. In addition, the annual tariff setting and other factors can lead to under-recovery or over-recovery against allowed income which also results in profit swings. It is for the DNO to explain these fluctuations to shareholders, bond holders and rating agencies as they occur.

Protecting against financial failure

253. At paragraph 5.31 of the *Initial consultation* reference is made to the licence arrangements that are designed to protect customers and the regulatory regime from the consequences of a financial failure of a licensee. We agree that it would be timely to review these arrangements now and we look forward to participating in this debate with Ofgem.

Treatment of taxation

254. Tax issues were given greater importance in DPCR4 by the move from a post-tax to a pre-tax measure of the cost of capital. At that time the possibility of some form of correction mechanism was discussed and ultimately rejected.

255. One of the assumptions for DPCR4 was that capital expenditure (measured on a statutory basis) could be allocated to the different tax allowance pots on the basis of generic proportions. We still consider this to be inappropriate as it does not reflect

what could be different profiles of expected expenditure at each DNO. With the RRP process there is now a specific history that can be used as a base on which to model specific allocations. This could be extended to take account of any changes proposed in the future investment plans that result for each DNO.

256. The High Level Business Plan Questionnaire (HLBPQ) issued in May 2008 includes this information as it relates to the years from 1 April 2008 to 31 March 2015. Having been provided with this specific information, which should be updated as the investment plans develop over the coming months, we would expect it to be used year-by-year and DNO-by-DNO, and not replaced by averages.

257. The 2007 Budget included some unexpected changes to both the tax rate and the application and timing of capital allowances with effect from 1 April 2008. As a result there will be a net cash benefit to both NEDL and YEDL in the last two years of DPCR4.

258. We do not know what legislative changes might occur during the DPCR5 period. With the experience of the DPCR4 period we would understand if Ofgem wanted to bring in some form of correction mechanism for the DPCR5 period. However, it would only be appropriate to cover changes in legislation that impacted upon either the tax rate or the application of the tax allowances as applied to periods starting after 1 April 2010. In this case the impact would also be limited to a restatement of the tax allowances that would have been applied in the modelling for the DPCR5 period, had there been perfect foresight of the tax regime. The correction mechanism would be applied without any reference to levels of actual expenditure or income.

259. There would be the need to define what constitutes ‘major’ and it would seem appropriate to measure that by reference to the NPV of the allowed tax. For example the NPV (in 2002/03 prices) of the cash tax allowances for DPCR4 was £60m (NEDL) and £100m (YEDL). If ‘major’ was set at, say, 10 per cent of the tax allowances, then the thresholds of £6m and £10m would each represent around one per cent of the total DPCR4 allowed income (in NPV, 2002/03 prices).

260. We are prepared to reprise the previous discussions to see if there is a workable method for the DPCR5 period that would limit the risk exposure to customers and shareholders.

Claw back of tax benefits of excess gearing

261. The cost of capital is set at an assumed level of gearing that then directly sets the degree of tax relief that is reflected in the allowed income. Gearing above that assumed level brings additional tax benefits at the same time as introducing the risks inherent in the additional gearing. We agree that the tax benefits, accruing from levels of gearing above that assumption, should be the subject of a correction mechanism to provide an appropriate disincentive to less robust financial structures.

Gearing assumption

262. As explained previously we expect Ofgem to settle on a gearing assumption that does not promote further moves to a thin-equity model. We see a continuation of the requirement for the DNO to maintain an investment grade credit rating, so gearing below 60 per cent would seem to provide an appropriate margin to ensure that the allowed cost of capital provides an incentive to stay within this level. As indicated in the *Initial consultation*, Ofgem intends to continue with the correction mechanism if gearing rises above its assumptions.

263. Of course the actual gearing of the DNO is for the owners to determine, recognising the need to maintain the credit rating and also to ensure robust finances giving resilience to short-term financial shocks and providing long-term financial stability.

RAV

264. Market valuation of DNOs involves a degree of circularity in that the ultimate value is driven by Ofgem, with the DNO having only a marginal impact through genuine outperformance against the incentive targets and decisions on capital investment.

265. However, Ofgem has also to recognise that RAV is really an IOU in that it represents money the DNO has spent, and Ofgem has 'accepted', but customers have yet to pay for it. With these sunk costs the only variability that should be experienced is in respect of the cost of capital that is set at subsequent reviews. There can be retrospective adjustments to the amount of the RAV but only in order to reflect the actual money spent, to the extent that it is different from the Ofgem assumptions, and after taking account of any incentives already earned as a result of that difference.

266. Annual RAV additions should also follow the same principles. By including it in its calculations Ofgem accepts that the money is 'well-spent' and the decision then is which generation of customers are going to pay by treating some as opex and the rest as RAV additions.

267. We have previously met with Ofgem, and participated in the May 2008 workshop, to explain our views on the issues of RAV premia and market asset ratios (MARs). In summary these measures are not reliable as a means of valuing other companies. RAV premia reflect an assessment of one transaction undertaken between two parties at a point in time for a variety of reasons that blur the derivation of any number. Whilst cost of capital will be a factor, we do not consider that recent transactions provide evidence of a decline in the required equity return. In contrast, we consider that a high premium flows from a number of over-optimistic assumptions and from the inappropriate value assigned to the benefits of the up-front cash flow from index-linked bonds.

268. MARs also suffer from the same issues as well as the added problems associated with disaggregating an overall market value to derive segmental values.

269. From what we can see in the public domain there is nothing to indicate that the ultimate lenders of funds to the recent transactions are expecting equity returns at, or below, the existing DPCR4 levels. This means that the premium is the result of other assumptions, which may or may not be robust either now or in the future. Such assumptions cannot play a part in deriving the return that other long-term players should receive.

270. Looking forward, the ever-changing business environment and the additional requirements that DNOs will be expected to satisfy indicate an increasing degree of risk that must be reflected in the cost of capital.

Treatment of excluded services

271. It has been identified by Ofgem that a better solution is required in order to deal with the costs attributed to excluded services. The current method derives the cost by using the income as a proxy and then requires a correction to RAV of the difference between the forecast level of revenue and the actual level of revenue once this is known. This true-up causes the revenue earned over and above the forecast to be eradicated.

There is therefore little advantage in delivering increased levels of service in this category , or indeed incurring costs that will increase excluded service income.

272. The appropriate solution will need to satisfy the following criteria. It must:

- incentivise the appropriate behaviour;
- allow the DNOs to charge the recipient of the services directly where this is more appropriate than charging the mass of customers;
- treat uncertainty most appropriately by linking controllability with risk and reward; and
- minimise the administrative burden for both Ofgem and the DNOs.

Finalising DPCR4 RAV

273. Reference is made at paragraph 5.45 of the *Initial consultation* to the need to adjust the closing value of the DPCR4 RAV to reflect discussions that are continuing on matters of interpretation. We are pleased to note that Ofgem has recognised that there are outstanding issues that need to be resolved to provide the appropriate starting point for the DPCR5 period.

274. In terms of the issue relating to direct labour, this has been the subject of communication with Ofgem since 2005 and we have sought to draw it to a conclusion on a number of occasions. Our position remains that we agreed to the DPCR4 *Final proposals* including Appendix 1, which details the key assumptions and principles to be applied in calculating RAV additions for the DPCR4 period. We request that Ofgem allows CE to apply these principles rather than to seek retrospectively to reinterpret the meaning.

275. There is a need for some concerted effort to clear out these issues as a matter of some urgency and certainly prior to the increased levels of price control activity that will involve DNOs and Ofgem collectively during 2009.

Revenue adjustment

276. Paragraph 5.46 of the *Initial consultation* correctly states that the DPCR4 Final proposals made clear that ‘material’ variation between 2004/05 RAV additions and those assumed in setting the DPCR4 price controls would be adjusted for at DPCR5. In arriving at a judgement of materiality we would suggest that Ofgem should recognise that this materiality should be seen in the context of the lead-times to establish levels of capital spending and that any judgment of materiality is based on a longer than annual view of the capital programme. Ofgem may also which to consider the adjustment in the context of capital spending in the DPCR4 period.

277. Notwithstanding the above, our level of under-spending bears scrutiny even if considered on the annual basis. When we notified Ofgem of the magnitude of our divergence and Ofgem did not dissent from the view that these amounts were not material in this context. We would therefore not expect any adjustment in the case of NEDL or YEDL.

Treatment of pensions

278. We are keen to participate in the separate pension consultation scheduled for later this year as mentioned in paragraph 5.48 of the *Initial consultation*. The 2007 valuation is now behind us and contributions are therefore known for the remainder of DPCR4.

279. DPCR5 will involve estimates of the valuations in 2010 and 2013, so it is likely to require a continuation of a pension correction mechanism.

280. It is also appropriate that we reconsider the degree to which contributions are disallowed in the DPCR5 period, if there have been changes in the constituents of each scheme, together with the impact that the element of deficit contributions that were disallowed in the DPCR4 period had on the results of the 2007 valuation.

PROCESS AND TIMETABLE

281. In reviewing the proposed process and timetable we broadly support the process as set out by Ofgem and believe that the clearly established milestones of submissions, workshops and Ofgem policy/proposal documents is beneficial.

282. We maintain that the September 2009 checkpoint should include an update paper (or some other formal quantified published statement) as well as the proposed workshop. Although the process as set out allows appropriate interaction (bilateral meetings and presentations to the Authority) in the six-month period (June-December 2009) between initial and final proposals, it significantly allows for no assurance on those items that have been effectively determined at the mid-point of that period. The update paper is an important component for Ofgem to make clear to DNOs and other interested parties how thoughts are crystallising and will form the basis of the information that would be needed to create a presentation that makes the workshop meaningful.

283. We ask that Ofgem change its stance on this issue and plan to issue an update paper with the proviso that this plan may be changed in the unlikely event that the update is mutually agreed as being unnecessary.

284. The area where we would wish to see more clarity is in the processes and working groups that will ensure the policy is effectively converted into practice. We wish to see co-ordination of the various Ofgem workstreams and clear milestones established in each area so that DNOs may contribute fully to the process. This co-ordination and structure are currently missing, making effective working together more difficult.

285. It is our view that the expert consumer panel will need to work alongside the DNOs' own stakeholder consultations and should ensure that the top-down policy and objective setting by Ofgem are aligned to the bottom-up forecasts constructed by DNOs.

286. We support Ofgem's intention to issue specific impact assessments on each of the policy issues to be determined rather than an overarching DPCR5 assessment and agree that the review should be viewed as a continuation of an existing policy that does not necessarily require an impact assessment of the overall price control review.

287. Incentives depend upon clarity. At DPCR4 we proposed that Ofgem should set out clearly how expenditure incurred during the DPCR4 period would be treated at DPCR5 insofar as this could be done without fettering the discretion of the Authority. This resulted in Appendix 1: RAV Roll Forward and Incentive Mechanisms of the DPCR4

Final proposals. This Appendix has been useful but it could have been better still if it had been clearer about Ofgem's commitments. When we were assisting Ofgem with this, the point was made to us that to give greater clarity at the final stages of the review would only have been possible if this had been envisaged at a much earlier stage. We therefore recommend that at DPCR5 Ofgem makes clear from the outset that it intends not only to determine allowed income for the DPCR5 period but also to give very clear commitments about the future treatment of expenditure that will be incurred in the DPCR5 Period. This is especially important in the light of the 'RPI@20' project.