ANNEX

Response to Consultation Paper's Questions

<u>Chapter 1 – Introduction and Overview</u>

Question 1: Do you agree with our assessment of how the DPCR4 settlement has performed in practice?

The DPCR4 incentive mechanisms should be modified so that those Distribution Network Operators (DNOs) that are performing well, meeting their commitments and investing in the future are rewarded financially. The forecast returns on equity in DPCR4 range from 6% to 11% compared to an allowance of 7.5%; those DNOs that are reaping excess returns for their shareholders are also delivering quality for their customers.

Question 2: Do you agree with the main lessons we have drawn from this assessment?

Breaking down the forecast returns on equity in DPCR4 into their constituent parts shows that the weightings between incentives are inappropriate.

The average return on the losses incentives is forecast to be over three times greater than the Interruptions Incentive Scheme (IIS) incentive. Losses are largely outside the control of a DNO whereas management has a direct bearing on IIS performance.

We agree that DNOs should develop a set of clear output measures which support their capex forecasts. We disagree with the statement in para 1.30 that if a DNO achieves its outputs but underspends its capex allowance due to investment deferral "then any investment deferral can be seen to be efficient because it is not increasing network risk and it should be appropriately rewarded".

Our view is that:

- Investment deferral should not be rewarded because in retrospect it was not required in the business plan.
- Capex underspend should be rewarded only if efficient and not due to deferral.
- Capex overspend should not be penalised if efficient because in retrospect it was required in the business plan. As stated by Ofgem, a capex allowance should not be treated as a budget, and so DNOs should not be discouraged from overspending if it is necessary to maintain the condition of the network and meet other customer interests.
- The Information Quality Incentive (IQI) mechanism should be retained for assessing capex forecasts, but the IQI/capex rolling incentive is unnecessary for capex performance if a return on equity methodology is introduced. With the capex rolling incentive, DNOs who underspend their capex allowance benefit their shareholders not only from the cash saved but also subsequently receive additional revenue for making these supposed savings. This seems wrong. Ofgem are concerned with the extent to which DNOs are underspending their capex allowances; this suggests that the IQI/capex rolling incentive is not delivering the desired outcome.

- Outputs should be separately assessed; out-performance/under-performance should be rewarded/penalised

Question 3: Have we identified appropriate measures to address our concerns and deliver a settlement that provides better rewards/penalties for highly performing/ poorly performing companies?

We agree with the introduction of a rate of return methodology and output measures that provide better rewards/penalties for highly performing/poorly performing companies.

Ofgem frequently express concern about the poor quality of data they receive from DNOs. We propose that Ofgem introduce a Reporting Accuracy Incentive. Such an incentive would entail an assessment through audit of the IQI, Regulatory Reporting Pack (RRP) and other regulatory information. The incentive could be dealt with by increasing the ROE for companies that report accurately and reducing the ROE for companies that do not.

Question 4: Do you think our proposal to base DNOs' incentives for under/outperformance around their effective return on equity is appropriate?

We agree with the holistic approach that the return on equity methodology offers to base DNOs' incentives for under/outperformance.

In the table below we propose an incentive framework adopting a return on equity methodology which:

- Allows higher/lower rewards and penalties for a DNO prepared to take more/less risk
- Provides a trade-off between underspend/overspend on capex and opex to exceeding/failing on output targets

We propose that the return on equity methodology be implemented on the same basis as the IIS currently in place.

Incentives Incremental Range: Return on Equity – WPD Proposal

Incentives Incremental Range: Return on Equity

	Cap		Collar		Comment
	Harder Target	**Easier Target**	**Harder Target**	**Easier Target**	
Operational: Output					
All DNO Metrics:					***DNO chooses target profile (i.e. risk profile)***
Quality Of Supply: IIS	1.6%	0.8%	-1.6%	-0.8%	IIS incentive equates to DPCR4 level at high risk
Losses	0.8%	0.4%	-0.8%	-0.4%	Weighting based on 50% of IIS
					Easier Target rewards/penalties 50% Harder target
DNO Specific Metrics:					***Ofgem and DNO determine target profile***
Customer & Network Performance					See note below
Environmental Sustainability	1.6%	0.8%	-1.6%	-0.8%	SF6 leakage, oil leakage, transformer bunding
Network Utilisation					Substation loading, MVA of capacity installed
Legal & Safety					Substation security & protection, ESQCR
Operational: Input					***Ofgem determine profile based on agreed outputs***
Capex Efficiency (after backlog)	0.8%	0.4%	0.0%	0.0%	0.75% = 10% underspend; no overspend penalty
Opex Efficiency	0.8%	0.4%	-0.8%	-0.4%	Cap/collar same as capex
					Potential gain matches potential output loss
					For opex and capex actual cost performance Easier Target rewards/penalties one half of Harder target rewards/penalties
Reporting Accuracy	1.0%	1.0%	-2.0%	-2.0%	Benchmark is 90%, Best 100%, Worst 70%; 10% worth 1.0%
Overall Cap / Collar	**4.0%**	**2.0%**	**-4.0%**	**-2.0%**	**Maximum & minimum allowed**

Question 5: If you do, what range of return on equity do you think would represent fair balance between customers' and shareholders' interests to reward increased efficiency, better service and innovation, whilst maintaining strong incentives for shareholders of any poorly performing DNOs to improve performance?

A DNO that is prepared to accept harder incentive targets is taking a higher risk, whilst conversely a DNO that accepts easier targets is taking a lower risk.

Shareholders of a DNO taking higher risks should be rewarded with a higher potential return/loss; we consider that the overall cap/collar should be +/-4.0% on the allowed return on equity which would be:

- Slightly above the maximum forecast to be achieved by a DNO in DPCR4
- Including the IIS incentive which in DPCR4 equates to a 1.6% return on equity.

Shareholders of a DNO taking lower risks should be rewarded with a lower potential return/loss; we consider that the overall cap/collar should be +/-2.0% upside/downside on the allowed return on equity.

Chapter 2: Environment

Question 1: Do you agree with our view of future uncertainties and the need for DNOs to change their way of working and thinking to encompass innovation and flexibility?

We agree that DNOs need to move forward with ideas as rapidly as possible. We agree that cost reflective charging, greater information about the flows on the network and consideration for the environment in our day-to-day operations is essential to delivering many of the environmental objectives. To this end we have:

- Led the DNOs in delivering locational charging at EHV from April 2007 and continue to be the only DNO to have an approved methodology in this area.
- Started the installation of smart metering at HV/LV substations which will be able to give real time access to data necessary to implement active network management (ANM) and demand side management (DSM) proposals. This proposal is the only large scale project proposed by a DNO to move the ANM/DSM issue forward.
- Adopted a policy of building new depots to achieve a Building Research Establishment Environmental Assessment Method (BREEAM) “Excellent” rating.
- Started installing smart metering in all depots and offices to enable energy efficiency monitoring to take place and contributing to the Carbon Reduction Commitment “early action” metric.
- Installed photovoltaic solar panels and improved insulation as part of the refurbishment of our training centre.
- Replaced significant number of our existing vehicle fleet with more fuel efficient/lower emission vehicles. We have also purchased electric commercial vehicles for operation in our urban centres and entered a UK scheme to trial electric cars.

Question 2: What are your views on our proposals for DNOs to provide more information to help low carbon initiatives and have we adequately identified and defined the information requirements?

We agree that DNOs can provide more information about the distribution network to those seeking to connect. Whilst the proposals for more information are headed ‘for DG’, we believe that if systems/processes are to be established for DG, it would seem sensible to consider what extension of these would be required to make them applicable to load connections. The data provided by the proposed installation of smart metering in HV/LV susbstations could be use to develop 11KV circuit heat maps for customer use.

A more detailed scope for the proposed web-based indicative costing tool and 11kV circuit heat map is needed to allow consideration of the practical options available, as systems that undertake fully automatic loadflow, voltage profiles and fault level analysis, together with establishing variations on capacity/reinforcement break points, as well as alternative locations, are beyond the scope of existing systems currently produced by software vendors.

In a similar way, it may be easier to produce locations where the connection of new loads or generation would be particularly expensive rather than those which are best.

Question 3: Do you agree with our proposal that all distributed generation should pay use of system charges, and if not, can you provide evidence to substantiate your specific concerns?

We agree that all distributed generation should pay use of system charges. The issue is whether generators connected on pre April 2005 terms should be compensated.

Despite discussions at various forums, Ofgem have been unable to propose a solution for compensation that is practical, given the information available for the actual costs paid for connection for many of these generators. There are two practical options if all generators are to pay use of system charges:

- No compensation and use of system charges payable by all generators from April 2012 or,
- Use of system charges become payable 15 or 20 years after initial connection of a site.

It is more likely that generators would accept option 2, but both options may need legislative changes, as changes to existing terms and conditions in connection agreements will need to be accepted by generators.

Question 4: Do you agree that the distributed generation (DG) incentive should be retained? Should embedded transmission be deemed relevant DG?

As there is uncertainty over the quantity, location and timing of future DG there appears to be no option but to continue with a DG incentive arrangement. Embedded transmission has characteristics very similar to large DG connections and hence should be deemed relevant DG.

The current approach of having separate price regulation for generation and demand results in significant volatility to generation prices due to the small number of generators subject to UoS charges. The two ‘pots’ need to be brought together to facilitate price stability.

Question 5: What are your views on our proposals on innovation and flexibility? How would you rate their feasibility and which option is most likely to drive the more innovative and flexible behaviour that we are seeking?

Option 2 provides the best balance between being able to react to changing needs and bringing forward solutions, whilst giving DNOs a reasonable degree of certainty that that there is regulatory agreement that the proposals are likely to provide benefits to customers.

Option 1 does not allow DNOs to respond to changing requirements and option 3 transfers the entire risk to shareholders with little opportunity for, or guidance on, how that risk can be mitigated.

Question 6: What are your views on our proposal to set an incentive on transmission grid exit charges?

We do not agree that an incentive on transmission grid exit charges is required or that there is evidence that distribution networks have been developed uneconomically to take advantage of the current arrangements. The problems with this proposal are that:

- the profile of existing charges is a saw tooth, hence existing contracts will change over time
- we have no influence over the price risk
- there are proposals for transmission connections by generators which will cause third party works including the addition of new exit points and enhancement of others – the treatment of these costs is currently unclear

Should such an incentive be introduced, it will need changes to Connection and Use of System Code (CUSC) to allow much greater scrutiny of National Grid outturn costs on their works and greater ability to challenge these.

Question 7: What are your views on our proposals, and do you have any additional comments on the option to install smart meters on low voltage substations?

There are serious issues with the use of settlements data to calculate losses which result in large errors causing volatility in allowed revenue and volatility in end-customer DUoS charges.

We are progressing the installation of metering on the LV side of all HV/LV substations. We have already started a trial of installing this metering on the substations fed from one 66/11kV substation on our south Wales network. Completion of the installation work for this trial has been completed with data available in March. In conjunction with metering installed at the 66/11kV substation this will allow the accurate measurement of the losses on the HV system fed by this 66/11kV substation. Once Balancing and Settlement Code (BSC) Modification P222 is implemented in August 2009, we will also have access to Estimated Annual Consumption (EAC) and Annualised Advance (AA) data at a customer level from suppliers. As customer connectivity is known this will allow comparison of settlements data with actual substation throughput. This demonstrates the accuracy or otherwise of settlements data and will also give data to support a decision on whether IDNO connections should be metered or rely on aggregated settlement data.

Whilst a range of commentators, including the European Union, regulators and researchers agree that there is no current definition of a “Smart Grid”, there is wide consensus that it encompasses the following elements:

- management of network constraints
- loss reduction
- demand side management (including electric cars)
- absorption of distributed generation – load and voltage control
- integration of customer smart metering
- outage alert
- semi autonomous operation
- communication hubs

The WPD HV/LV metering trial will facilitate many components of the above by:

- provision of ready accessible voltage, load current and frequency inputs
- provision of ready accessible current transducers (CTs)
- distributed intelligence at the HV/LV s/s
- communication path back to WPD server

Once the trial has satisfactorily demonstrated the required functionality and reliability, WPD propose further development to assess the viability of remote terminal units (RTUs) in place of smart meters.

If the existing incentive is to remain then caps and collars are essential to protect both customers and shareholders from odd and unexplained swings in settlements data. The value of incentives must be ranked in accordance with the DNOs' ability to influence the parameter being incentivised. The gain/loss associated with the loss incentive should not exceed half the value of the IIS incentive as DNOs have much less control over losses compared to system performance.

As highlighted in para 2.87 of the paper, there is considerable volatility in the difference between the metered input from the grid and generators and the continually estimated usage by customers. This means that the target level for the loss incentive should be based on a long average – at least 10 years.

Question 8: What are your views on the various aspects of the business carbon footprint proposals?

We are supportive of Business Carbon Footprint (BCF) reporting on a "Scope 1" basis, and have been undertaking Greenhouse Gas Emissions (GHG) reporting for many years based on Department for Environment, Food and Rural Affairs (DEFRA) guidance. This reporting should encompass SF6 leak reporting and we agree that ENA Engineering Recommendation S38 (which is based on Inter-Government Panel on Climate Change (IPCC) guidance) should be the basis.

As stated (2.111 of the policy paper), it will be necessary to develop a common reporting methodology and in doing so, clarify reporting issues surrounding the formulation of boundaries on contracted out activities. These need to take account of the administrative cost impact on our contractors. The revised GHG protocol referenced in appendix 6 illustrates some issues surrounding what activities are under "control" of the DNO. The example on DHL on page 30 of the GHG protocol is analogous to contracted-out movement of stores, and has been classed as Scope 3, i.e. outside the proposed Scope 1 boundary.

Question 9: What are your views on our proposals for refining the undergrounding scheme? In particular, should we apply caps per km of cable by voltage level or should we remove all voltage caps and just have a single overall cap?

The undergrounding scheme stimulated a significant amount of debate from stakeholders across our area. Stakeholders' view was that customers should not be required to pay for a large programme of undergrounding as indicated by the Ofgem allowances for the WPD regions. Stakeholders did not favour a scheme based on a prescribed volume of overhead lines. Instead the consensus reached from special interest groups such as the

National Park Authorities and Areas of Outstanding Natural Beauty (AONB) Partnerships was for a limited programme of undergrounding prioritising key locations of "iconic importance" to the landscape and tourism. Sites should be identified and prioritised by the appropriate regional forums in conjunction with our engineers.

Given the stakeholder views expressed we do not believe that voltage caps are appropriate. The location of important landscape sites are often in difficult terrain, for example situated on granite. The cost of undergrounding in these areas can be very expensive. However stakeholders may consider the benefits at a particular site to be worthwhile, especially where this would contribute to wider economic benefits to the local economy.

Question 10: Do you agree with our proposed approach for the treatment of fluid-filled cables?

We support the EA/ENA Operating Code and have been undertaking monthly reporting to EA on that basis since early 2008. A risk-based approach to the management of fluid-filled cables (FFC) is the way forward. This can encompass a wide range of environmental risk mitigation including:

- Improved environmental risk assessment of routes
- Improved leak detection and location,
- Joint bay refurbishment and tanking
- De-oiling and flushing out of service redundant cable
- Risk and condition-based replacement of old cable

Our DPCR5 submission and Innovation Incentive Funding (IFI) work with Southampton University through Supergen Amperes encompasses all of the above initiatives. They are proportionate and were supported by stakeholders.

It is important to note that action on FFC also encompasses action on existing circuits that are not currently in service. Ofgem information returns usually refer to kms of cable in service and can understate both the overall lengths of installed FFC and ongoing action to reduce this figure.

The tensions inherent in seeking to manage an FFC inventory against the background of new and future legislation should not be underestimated, and it is important that the EA can see evidence that the operating code and DNO/Ofgem action is delivering ongoing reduction in leaks.

Other comments on Chapter 2

Distributed Generation
Distributed Generation (DG) connection boundary – the current connection boundary strikes an appropriate balance between up-front connection charges and ongoing use of system charges. A move to a super-shallow boundary (assumed to result in virtually no connection charges) moves to risk of paying for stranded assets (should the generator close soon after connection or just after the connection has been completed) to either all customers or shareholders or some combination of these.

Chapter 3 – Customers

Question 1: Do you think that the range of existing and proposed arrangements will deliver the levels of service customers expect?

We agree that current regulatory arrangements generally work well and in the main deliver the levels of service that customers expect. There are some areas where the current arrangements could be improved and we will work with Ofgem to achieve this. We comment on these areas in the specific questions below and or response to appendix 7.

Question 2: What percentage of revenue/return on equity should be exposed to customer service and how should it be split between the various areas?

Ofgem's customer research indicated that customers' value rapid restoration of supply most highly and have a low willingness to accept deterioration in either the frequency or duration of power cuts. Customers also indicate that they value proactive communication during outages, initiatives to improve service for worst-served customers as well as carbon reduction initiatives. This indicates the areas that should be targeted for customer service improvements and incentives.

These findings are consistent with our own stakeholder engagement which established that the top three priorities for customers in the south west and south Wales are:

- Maintaining current service levels.
- Protecting the network against severe weather.
- Reducing power cuts.

It is evident from both sets of research that the performance of the network continues to be the prime indicator of customer service. Therefore the current revenue exposure for CI and CML totalling +/- 3% should be maintained and incorporated into a return on regulatory equity (RORE) measure.

We support the methodology outlined in Appendix 11 to develop a RORE measure and we provide a proposed framework as part of our response to chapter one (see response to question 4). This includes service measures relating to network performance (CI, CML), losses, customer satisfaction survey, call centre performance and worst-served customers.

Question 3: Do you agree with our intention to develop a broad measure of customer satisfaction and the proposed advocacy approach?

We support retaining the current measure of call centre satisfaction, which already captures the majority of contacts with our customers and surveying customers in the connections market separately.

We are concerned that that a representative and consistent survey of broader customer satisfaction across DNOs will be difficult to achieve and will not provide clear messages that drive actions to improve our customer service levels. Many of the customer satisfaction attributes suggested could be better measured by objective indicators such as the number of complaints, Ofgem determinations and speed of telephone response. This could be achieved using data that is already available to Ofgem.

The proposed "advocacy" approach may be difficult to apply to a regulated monopoly. Unlike the railways, the majority of electricity network customers do not experience the whole range of DNO activities, and in most cases have no alternative choice of service provider. Customers would be asked how they "feel" about a DNO based on only a partial experience of that company's service. There is also a significant difference between customers who experience a planned or unplanned interruption to supply and those who request us to carry out work on their individual connection. These features would make the survey complicated to design, expensive to operate and possibly unreliable.

Data about satisfaction with new connections, service alterations and supply upgrades should instead be gathered as part of the increased regulation of connections to avoid duplication. A low cost advocacy survey in this area may be more cost effective and meaningful as it relates to areas where there are comparable service providers available in many cases, and customers will usually have contacts multiple contacts with the DNO throughout the process of arranging the work to be undertaken.

Question 4: Do you agree with our proposed approach to connections, which of the options do you support and why?

We do not support Ofgem's proposal to allow a margin on contestable charges and we do not understand how this can be in the best interest of all customers in either the short or long term. Whilst competition is clearly evident around major cities in the south west and south Wales, the proposal appears to suggest that prices should be increased throughout WPD territory including rural areas where competition is unlikely to be attractive to third parties.

Additionally, the policy paper and supplementary appendices present a picture of competition in connections that we do not believe is representative of WPD. We have always sought to provide a professional and co-operative service to all parties requesting connections and are zealous at maintaining good customer relations and in dealing co-operatively and fairly with ICPs and IDNOs.

- Table 3.2 of the policy paper refers to the volume of complaints to energywatch and referrals to Ofgem for determination. WPD have not had an energywatch/ombudsman complaint or Ofgem determination in five years.
- We favour direct dialogue with those seeking connections, be they developers, ICPs or IDNOs.
- We have long operated arrangements which provide from the outset of an enquiry, a single named planner and direct contact number.
- Our senior managers meet developers to discuss their needs.
- We have lead nationally on developing triangular contract arrangements with street lighting authorities, and have been publicly complimented on this work by those authorities in Ofgem ECSG.

The proposal to introduce a connections margin will not address the main concerns raised by non-DNO respondents to the initial consultation document which relate almost entirely to the customer service associated with either providing quotations or carrying out site works.

We comment in more detail on Ofgem's specific proposals and initiatives relating to connections activity in our response to appendix 7 of the policy paper.

Question 5: do you agree with the proposed amendments to the IIS *(in full) and what are your views on how incentive rates should be structured?

We comment in detail on the proposed amendments to the IIS scheme in our response to appendix 7

In general the quality of supply incentives are working well and therefore some refinements are welcome but wholesale changes are unnecessary. Many of the changes proposed in appendix 7 appear quite complex to administer but have little overall impact on the operation of the scheme. Change for the sake of change should be avoided and these issues should be quickly resolved to allow the focus going forward to be on the key issue of designing a scheme that delivers a good network performance for customers, rewards DNOs who delivers a performance that exceeds an agreed threshold and penalises DNOs that do not. The most important aspects to agree in this respect are the individual DNO targets, the bandwidth around these targets and associated risk/reward profile. WPD will work with Ofgem to ensure that these key criteria can be agreed for our network.

It is clear that there are still wide performance differences between DNOs and we do not support the proposal that upper quartile calculations for DPCR5 should be calculated in a different way than for DPCR4. It is not appropriate to change the way that upper quartile performance is calculated because the target is seen as too difficult by some DNOs when it is being achieved by others. In 2006/07 both WPD South West and WPD South Wales were upper quartile performers for every one of the 23 circuit bands in the benchmarking process. As a frontier performing DNO, we should be given an allowance, as in DPCR4, to support a target that that reflects our current level of performance. This would lock in the current level of performance and encourage further improvement for customer's over the price control period.

Frontier performance is a valuable mechanism for revealing what DNOs are able to achieve. Where there are wide differences in performance, that cannot be explained by network differences, such those that exist with average restoration times, then a principle was established in DPCR4 that the frontier performing DNOs were recognised and rewarded. It is our view that this frontier performance in relation to average restoration time should continue to be rewarded in the same way as in DPCR4.

In theory the equalisation of incentive rates with greater links to customers' willingness to pay makes good sense. In practice, as demonstrated in the policy document, it is very complicated to achieve and we are unclear if there is any overall benefit, given that the current system is working well with a clear linkage between reward for good performance and penalty for poor performance. It is not possible to give support to this proposal without greater certainty of the target mechanism, thresholds for exceptional event exclusion and allowances for improvements, as these will provide a better view of risk and opportunity.

Question 6: Do you agree with our proposed longer-term objective of DNOs being able to automatically know which of their customers are off supply and the exact times, and if so what is the appropriate timescale to achieve this?

We support the proposed longer term objective of being able to automatically know which customers are off supply together with the exact times, providing this can be achieved at a cost that is commensurate with any benefits arising from this additional data being available. Currently WPD can automatically identify customers off supply at HV feeder level only, although implementation of our proposed losses initiative which involves installation of enhanced metering at distribution substations will provide the additional benefit of automatic no-supply notification at LV substation level. The trial we are currently conducting will allow us to investigate this area further and will provide an indication of the metering, communication and data storage requirements to assist with achieving this long term objective.

Ultimately, the ability to identify individual properties off supply will depend on the roll-out of smart meters to all customers and this is provided for within the Energy Act. Under the current timetable Department of Environment & Climate Change (DECC) are indicating that a roll out of smart meters to all domestic customers will be mandatory by 2020, although the timescale will be shorter for larger business customers and could be accelerated for all customers following consultation. The current model proposed by DECC is based on energy suppliers developing an energy services market that includes the roll out of smart meters and hence both the timescale and the availability of the required data may be outside of the control of a DNO. There is also uncertainty over the range of functionalities and communication regimes which will be common across the envisaged population of smart meters. Given these facts, the most appropriate timescale would be one that is consistent with the completion of the roll out of smart meters nationwide which is likely to be 2020. We would be happy to contribute to the appropriate DECC work stream to ensure that this option is fully considered as part of the smart meter roll out programme.

Section 3.37 of the policy document extends this objective to include both real time and historic incident data being made available to customers via the DNO web-site. We would be happy to investigate this option further during DPCR4 to assess the costs and benefits to customers. We already provide historic incident data to customers upon request and agree that there may be scope to extend this service further.

We are not convinced that there is any customer demand for live outage information. Most of our customers do not have access to the internet during an outage and our feedback from customers indicates that only a small minority have any desire to view outage information routinely. We believe customers prefer direct contact with our call centre to get information on the progress of an outage and an estimated time of restoration.

Question 7: Do you agree with the proposed focus on worst-served customers and which of the options do you prefer?

We comment in detail on the proposed focus on worst-served customers in our response to appendix 7

In summary, we support the proposed focus on worst-served customers and agree that a definition based on multiple HV interruptions should be adopted. Expenditure to deliver real performance improvements to worst-served customers was one of the most popular options from our stakeholder engagement programme, supporting Ofgem's conclusion that changes in the guaranteed standards are not the most appropriate tool for tackling this issue. We agree that it would be sensible for Ofgem to initially provide a set allowance for worst-served customer improvements with a view to moving towards an incentive in future. The allowance should be shared amongst DNOs based on consideration of the number of worst-served customers as a percentage of the total customer base (option 4 in appendix 7) and based on the actual costs of providing circuit improvements as set out in the business plan and reviewed by Ofgem. We will review our business plan proposals to establish what can be realistically achieved for the proposed £1000 per benefiting customer cap.

We envisage that once Ofgem and DNOs have agreed funding, an output measure could be developed for this expenditure based on a reduction of worst-served customers by an agreed target quantity for an agreed set of circuits. A balance will need to be struck between a mechanism that results in an overly prescriptive scheme (e.g. requiring Ofgem to approve each scheme in advance) and one that encourages efficient investment in this area.

Following a period of data gathering, an appropriate incentive could then be established to reward out performance and penalise under performance. We suggest DPCR5 is used as an information gathering period with the intention of implementing an incentive scheme for worst-served customers in DPCR6.

Question 8: We have raised some detailed questions throughout this chapter and the appendix. We welcome views on these issues.

Our comments in relation to the detailed questions throughout Chapter Three are included below and the topic headings follow the same order as the document. There are further detailed questions included within appendix 7 and we have included our response to these within a separate attachment.

Complaint handling
We agree that Ofgem should seek to monitor complaint handling more widely through the newly implemented complaint handling standards. An objective measure of complaint numbers (expressed per 10,000 customers) should be included as an incentive within the proposed return on equity measure.

Broader customer service measure
See response to Question 3 above.

Telephony incentive scheme
Our views on the proposed changes to the telephony incentive scheme are as follows:

- Streamlining the existing survey questions.
  We support the streamlining of the existing survey questions as outlined.
- Widening the scope of the survey to include calls answered by messaging.
  We support the widening of the scope of the survey to include calls answered by messaging.

- Taking account of the proportion of unsuccessful calls in assessing incentive payments.
  Given the value that customers place on the ease of access to a DNO call centre then we believe that this should be incentivised as a separate measure based on an objective measure of unsuccessful calls.
- Having the DNOs run a uniform assessment, approved by Ofgem, by contracting with a single provider.
  Allowing the DNO to carry out customer surveys using its own staff will always be the most cost-effective option and will provide valuable real time feedback. This would be our preferred option for any ongoing survey work during DPCR5.

  If an Ofgem specified survey is conducted via an independent research agency then it is irrelevant who commissions the work (DNO or Ofgem). The process is unaltered in terms of speed, the data protection issues are the same and the cost of the work will be passed onto the customer in either scenario.

Connections
We wish to draw attention to an error of degree of competition represented in Table 8 of the policy paper supplementary appendices. The table has excluded all connections made by IDNOs, yet in recent years these have dominated the competitive connections market and their exclusion distorts the impression of movement in competition. Taking Table 4.1 of the Connections Industry Review (CIR) 2007/8, it states that of 11,310 connections in WPD South Wales, 69 were adopted but 401 were provided by IDNOs.

The inclusion of DNO affiliate connections as being included as “competition in connections” is also questionable; the CIR showed that of 27,928 connections in SP Distribution 36% were made by the DNO affiliate.

<u>Key issues with current framework</u>

The Policy Paper contains a bulleted list of “potential barriers” under paragraph 3.22 we would comment on several of these:

- Ability to complete final connections – on LV live working, we have always maintained that the key issue is ensuring that whatever party undertakes the work they must be able to demonstrate competence in identification and jointing onto the range of cables present on our system. This is not imposing a barrier to competition; it is appropriate and proportionate regard for safety and legal compliance. The Health & Safety Executive has pursued prosecution of a DNO on far less obvious interpretation of a “joint work site” than working on a live DNO-owned cable. It should be noted that we have lead on opening up competition on unmetered supplies via “triangular agreements” with Street Lighting Authorities.
- Poor co-operation with new entrants – as stated above, we seek to deal co-operatively and fairly with Independent Connection Providers (ICPs) and IDNOs. The SLC15 regime is intended to set appropriate timescales and provide KPI data which would identify DNOs that were slow in provision of services.
- High start up and accreditation costs for ICPs – it was in response to this concern from ICPs that arrangements were established to just have accreditation for live wavecon jointing, so that all new on-site joints could be undertaken by the ICP without the need to be accredited across every type of LV cable that pre-exists on the DNO system.

- Complexity of electricity connections processes compared to gas - it should be recognised that the range of electricity system assets and their related safety requirements are not analogous to gas pipe jointing.

Guaranteed standards
We agree with the position set out on in appendix 7. We would like to see the unlimited financial exposure under the 18 hour guaranteed standard removed in the event of a high impact low probability event.

Customer reward scheme
The current scheme already requires DNOs to indicate which of the best practice initiatives it has adopted. We expect that the judges take account of this when assessing each application. This has encouraged DNOs to adopt and build on many of the best practice initiatives. However we do not feel that the scheme would benefit from making it a requirement to adopt all initiatives identified as best practice as this would automatically disqualify any DNO that chooses not to adopt any one or more initiatives.

We do not support a licence requirement to adopt best practice with regard to priority service customers. Such a requirement would discourage DNOs from bringing forward new initiatives, which could ultimately result in enforcement action if the initiatives could not be sustained. Many of the initiatives rely on partnerships with third parties such as Women's Royal Voluntary Service (WRVS), the police service and oxygen companies. It is not appropriate to require these arrangements to be permanent.

Number and duration of interruptions
We do not support setting targets for a period extending beyond DPCR5, as we do not believe it is achievable in isolation. IIS targets cannot be finalised without also reaching agreement over corresponding levels of opex and capex to achieve the targeted level of performance. We would not be able to commit to IIS targets for DPCR6 unless it was also able to agree with Ofgem the levels of expenditure necessary to achieve the required performance.

Chapter 4 – Networks

Question 1: Have we identified the right behaviours for DNOs? Are there others which should be included?

We agree that the right behaviours for DNOs have been identified.

Question 2: What action should we take where a DNO has deferred investment and created a backlog in DPCR4?

Investment deferral should not be rewarded because it is not efficiency, but may represent a deferral of improvements in customer service. A DNO which has deferred investment and created a backlog in DPCR4 should not receive any revenue benefit through the current IQI/capex rolling incentive mechanism.

It is not surprising that some DNOs are unable to fulfil their DPCR4 capital expenditure programme targets if they have not put sufficient investment into recruitment and training across the period. Unite has carried out a survey of apprentice recruitment and training across all DNOs and it is clear that WPD stands out in increasing manpower resources well in advance of DPCR5. WPD has recruited and trained more adult and young apprentices over the period and up-skilled more technician grade staff than any other DNO.

DNOs who have deferred investment as a result of under investment in recruitment and training during DPCR4 should not receive a revenue benefit in DPCR5. It cannot fair to give underperforming companies additional money to subsidise the cost of their not having taken actions they were adequately funded to have taken in the past.

Question 3: What approach should we manage to deal with volume uncertainty?

We agree that units distributed and customer numbers should be removed from the price control revenue formula, because these revenue drivers do not have a strong relationship with cost movements

There should be a fixed allowance to fund “baseline” investment and a variable allowance for a variance in the economic growth/volume assumption made for DPCR5.

Question 4: What approach should we take to price uncertainty?

Whilst we recognise that customers or shareholders should not unduly gain or lose from variances in key input price assumptions, we consider that it is impractical to implement an input price index. A significant proportion of costs relate to staffing which in practice track RPI and so are automatically hedged. We favour an ex ante approach with a trigger mechanism which only comes in to play if a DNO can demonstrate that costs have risen significantly above the assumptions made for DPCR5.

Question 5: Should we be looking to equalise incentives for opex and capex? If so, what approach should we adopt?

The DPCR4 rules governing cost capitalisation are too complicated. Equalising incentives would remove conflicting incentives and would reduce the reporting burden for the DNOs and Ofgem.

We would favour the approach that a common portion of the cost of indirect activities would be capitalised into the RAV. This would be a simple solution and would remove all cost boundary issues.

Question 6: Do you consider that we should make refinements to the IQI? If so, what changes should we make?

The IQI mechanism should be retained for assessing a DNO's capex forecast,. Under the capex rolling incentive, DNOs who underspend their capex allowance benefit their shareholders not only from the cash saved but also subsequently receive additional revenue for making these "efficiencies."

Ofgem are concerned with the extent to which DNOs are underspending their capex allowances; this suggests that the IQI/capex rolling incentive is not delivering the desired outcome.

Our preferred approach is:

- The IQI approach be retained for assessing a DNO's capex forecast.
- The accuracy of a DNO's forecast is taken into account in a return on equity mechanism with respect to an incentive rate on capex savings.
- Ofgem determine a DNO specific incentive rate on capex savings based on the accuracy of the forecasts and other factors - notably the level of outputs agreed by a DNO.
- Opex and capex savings are after excluding investment deferrals;
- Opex is defined as indirect activity costs and capex as direct activity costs.

Question 7: What action should we take where DNOs provide insufficient output information as part of their February FBPQ?

Where a DNO provides insufficient output information the DNO should be constrained through the return on equity mechanism.

Question 8: Do you agree with our proposed approach to assessing network operating costs and indirect costs?

Cost comparison
Progress has been made in developing the RRP thereby making a fair cost comparison between DNOs achievable as part of DPCR5.

In order to make a valid cost comparison the cost data is must be accurately compiled on a consistent basis and the cost driver for each activity determined. The use of statistical techniques is secondary, and likely to produce less reliable results.

Ideally, each activity should have an associated cost driver unique to it. However, in the interests of simplicity where activities have the same or closely related cost drivers, activity costs could be grouped together under a common driver. However, it is incorrect to group the call centre activity with network support. The two activities do not have a common driver and the call centre is an important indicator of a DNO's approach to customer service and should therefore be dealt with separately.

Regional Pay Adjustments

Labour and contract labour costs should not be adjusted by regional labour adjustments as there is no direct evidence that they vary. The only exception to this is London allowance, which is present in the distribution sector and in the construction industry.

- With the exception of any London adjustment, pay across the craftsman grade varies by approximately 5% (Unite survey 2008)
- JIB rates covering electrical trades in the contractor sector are national rates plus a London adjustment.
- Pay rates originated from national pay bargaining and so it is hardly surprising that with unions covering the vast majority of employees labour rates are consistent year on year, as one settlement provides the basis for the next
- The EdF model for regional pay adjustments implies regional variations of approximately 15% at craftsman level, far removed from reality.

The real issue is increased efficiency through devolving duties to the craft/ technician role. It is evident that few companies have followed WPD's example and not realised the obvious cost benefits as well as the opportunities to improve customer satisfaction through improved reliability.

The survey conducted by Unite shows the extent of gap between WPD and other DNOs in terms of training and developing staff into new roles.

Indirect Costs

Table 4 in appendix 8 to the Policy Paper lists Ofgem's current view of "cost groupings and appropriate cost drivers" for certain costs. Within this table engineering indirect costs (i.e. engineering indirects, network investment support and business support) are seen as being driven by "Network Investment Activity". This is incorrect and contradicts Ofgem's own data.

Table 2.1 of the "Electricity Distribution Cost Review 2007 – 2008", published by Ofgem in December 2008, is reproduced below. Also reproduced are Tables 3.3 and 3.5.

Table 2.1 Activity Costs on an RRP basis (2007-08 prices)

	Cash typical costs (£m)									
	Direct activities				Indirect activities					
2007/08	Load related (gross)	Non-load related (gross)	Non-operational capex	Network operating costs	Engineering indirects	Network/Investment support	Business support	Atypical cash costs	Pension deficit payments	**Total Distribution Business Cast Costs**
CN West	60	83	2	44	34	16	28	2	8	**276**
CN East	128	58	2	47	25	17	25	1	10	**314**
ENW	83	66	4	25	29	9	35	15	0	**266**
CE NEDL	46	43	4	27	17	10	19	0	22	**187**
CE YEDL	55	55	4	43	19	12	20	5	6	**219**
WPD S Wales	24	32	3	18	14	8	17	4	13	**135**
WPD S West	29	45	15	28	20	10	19	7	21	**193**
EDFE LPN	78	54	8	33	28	13	26	2	15	**257**
EDFE SPN	48	62	7	36	21	14	24	3	16	**232**
EDFE EPN	108	79	19	60	42	23	37	3	4	**375**
SP Distribution	49	68	3	24	27	14	23	2	2	**212**
SP Manweb	47	72	3	28	23	14	23	1	0	**210**
SSE Hydro	17	28	3	14	15	11	19	2	0	**110**
SSE Southern	94	49	8	46	30	22	29	3	27	**307**
Total	**865**	**793**	**85**	**473**	**344**	**194**	**344**	**52**	**143**	**3293**
2006-07	**700**	**699**	**95**	**468**	**326**	**209**	**340**	**53**	**222**	**3110**
2005-06	**709**	**590**	**71**	**451**	**309**	**219**	**352**	**17**	**300**	**3018**

Source: Ofgem Electricity Distribution Cost Review 2007-2008. Annual Report December 2008

Table 3.3 Cumulative capital expenditure compared to our DPCR4 assumptions (2007-08 prices)

	Actual	Actual	Actual	Allowance	Over/under spend to allowance	Over/under spend to allowance
	2005-06	2006-07	2007-08	DR4 to date	DR4 to date	DR4 to date
	£m	£m	£m	£m	£m	%
CN West	118	135	138	392	0	0%
CN East	94	119	146	387	-29	-7%
ENW	93	91	112	363	-68	-19%
CE NEDL	65	69	80	219	-5	-2%
CE YEDL	99	80	92	292	-20	-7%
WPD S Wales	48	51	54	155	-2	-1%
WPD S West	73	77	76	224	1	0%
EDFE LPN	90	103	109	349	-47	-13%
EDFE SPN	96	73	108	374	-96	-26%
EDFE EPN	117	140	180	542	-105	-19%
SP Distribution	77	92	100	292	-24	-8%
SP Manweb	94	101	102	314	-17	-6%
SSE Hydro	38	43	53	167	-33	-20%
SSE Southern	95	99	124	439	-122	-28%
Total	**1,197**	**1,273**	**1,474**	**4,510**	**-566**	**-13%**

Table 3.5 Cumulative operating costs against our DPCR4 assumptions (2007-08 prices)

	Actual	Actual	Actual	DPCR4 Allowance	Over/under spend to allowance	Over/under spend to allowance
	2005-06	2006-07	2007-08	DR4 to date	DR4 to date	DR4 to date
	£m	£m	£m	£m	£m	%
CN West	57	64	67	169	19	11%
CN East	64	62	62	180	9	5%
ENW	54	45	45	163	-18	-11%
CE NEDL	39	42	41	117	5	4%
CE YEDL	49	53	59	141	20	14%
WPD S Wales	34	33	32	110	-11	-10%
WPD S West	46	51	51	133	16	12%
EDFE LPN	47	55	58	142	18	12%
EDFE SPN	58	56	58	144	28	20%
EDFE EPN	83	93	102	223	55	25%
SP Distribution	57	49	45	152	-1	-0%
SP Manweb	58	49	47	126	28	22%
SSE Hydro	32	31	32	104	-9	-9%
SSE Southern	58	70	72	189	10	5%
Total	**738**	**753**	**770**	**2092**	**169**	**8%**

Source: Ofgem Electricity Distribution Cost Review 2007-2008. Annual Report December 2008

The tables show that in the period 2005/6 to 2007/8, a period during which network investment activity cost (i.e. gross load and non-load capex) increased by 27.6% from £1,299m to £1,658m Total Indirect costs have ***decreased*** by £2m. Therefore, far from engineering indirect costs being driven by network investment activity, the companies have between them spent £359m without any increase in engineering indirect costs at all – in fact they have decreased in real terms. These indirect costs are immune to significant changes in direct capex, and therefore are not driven by network investment activity.

Further, paragraph 2.12 of the "Electricity Distribution Cost Review" states that:

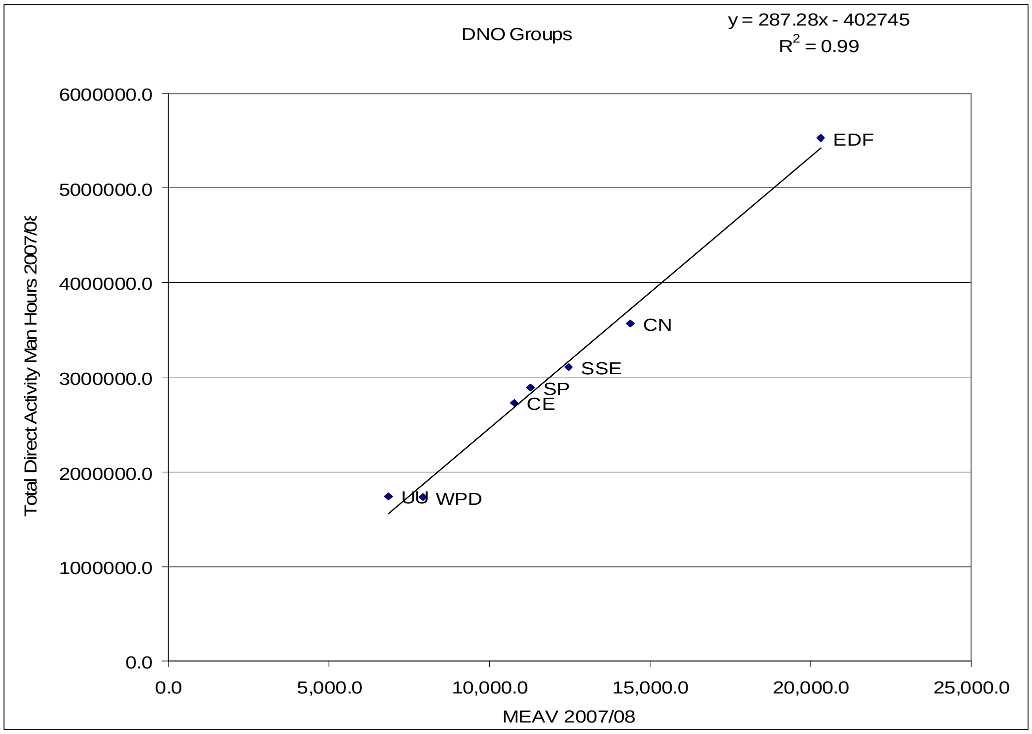
> *"The majority of DNOs have now developed new processes and introduced new ways of working regarding the procurement and management of external contractors. In most cases DNOs have now reached a level of resourcing, internal and external, required to deliver their capital programmes for the remainder of DPCR4."*

This being the case, the decrease noted above includes not only the cost of developing the new processes and new ways of working but also the level of resourcing is now at a level that will not need to increase for the remainder of the review as further increased capex is incurred in order to address the significant capex underspends in the first three years of the review.

<u>MEAV as a cost driver</u>

An appropriate measure of scale has yet to be agreed. Whilst Modern Equivalent Asset Value (MEAV) is a measure of scale, it is a measure of value *not* a measure of the amount of engineering management time input required. A more appropriate metric could be calculated by attributing standard working times and standard activity rates to the total population of each asset category.

However, this is complicated. Work we have undertaken indicated that MEAV is a good proxy for work required by the network (see chart below).



Question 9: Do you agree with our proposed approach for assessing network investment?

Load-related investment

We agree that the volume of low voltage connections is the main driver of investment in this area and that a linkage of volumes to allowances is appropriate.

General reinforcement at HV and LV tends to be fairly stable over time with little linkage to underlying growth as it is driven by localised factors. An allowance based on historic trends in this area is probably more appropriate.

At EHV, reinforcement is much more bespoke and dependent on the local network. Whilst the growth on individual substations will give an indication of the expenditure at substations, it does not give a good indicator of EHV circuit reinforcement needs. These, particularly on meshed networks, can only be assessed from load flow modelling and hence a more detailed assessment of our plans.

Non-load-related investment – asset replacement

We agree that a range of methods will need to be used to assess asset replacement spend. Whilst health indices have been developed for a range of assets, they only give a view of the current asset condition. Aging of these using Condition-Based Risk Management (CBRM) algorithms is currently unproven.

We agree that it is important that unit costs are assessed on a like-for-like basis. As many indirect costs do not vary with the volume of activity, it is important that indirect costs are not absorbed into the unit costs used.

Chapter 5 - Financial issues

Question 1: Have your views on the appropriate methodology for setting the cost of capital or on indexing the cost of debt changed as a result of the current turmoil in the capital markets?

Our views have not changed on the appropriate methodology for setting the cost of capital. Our view is not to be too reactive to the current market conditions at this stage, but rather to re-assess the situation nearer initial proposals in June/July.

We would favour retaining an ex-ante approach and avoid the introduction of a complicated debt trigger mechanism.

We re-iterate that the cost of capital is not just a theoretical exercise, but one which addresses financeability issues for all DNOs and as such sets at a common level.

Question 2: What is the appropriate timing of actuarial valuations for setting ex ante pension allowances (see also appendix 10)?

Ofgem considers that there are three options to this issue:

- Continue to use the latest available triennial valuation as this would reduce the cost to customers in the short term, accepting the potential true up in DPCR6 could or could not be a material amount, dependent on market conditions and investment strategies adopted by trustees.
- Base the pension allowance on DNOs' assessments of their pension costs over DPCR5, which would be supported by work from the scheme actuaries and subject to Ofgem review for reasonableness; or
- Introduce a re-opener when a new regular full triennial valuation is published.

We believe that Option 3 offers the best long-term solution of the three options as it allows for charges to customers to reflect most closely the actual amounts being paid, subject to the Pensions Regulator’s guidelines and Ofgem’s pension principles.

Chapter 6 - Process

Question 1: We invite views on which format stakeholders would find most useful for the Ofgem workshops to be held in January 2009.

Given the positive feedback received from participants, the format for the January 2009 workshops should be the same as the workshops run for the initial consultation document, with a series of presentations from interested parties followed by roundtable discussions. The presentations could be based around key policy themes and seek views on the options presented in the policy paper.

We have already advised stakeholders on the outcome of our stakeholder engagement programme and the consequential impact on our business plan. We have carried out feedback sessions with stakeholders in relation to the stakeholder engagement process (as opposed to the outcomes) and we are also participating in an industry review led by the Energy Networks Association on behalf of all the DNOs to establish best practice. Therefore, we do not believe it is appropriate to use the proposed Ofgem workshop to re-visit DNO stakeholder engagement as this will duplicate work already completed and there will be little scope to incorporate any new feedback into the business plan at such a late stage.

Question 2: We invite views on our proposed process

We welcome the setting out of the DPCR5 process, consultation approach and timetable. It remains important that the timetable is adhered to by both DNOs and Ofgem as the failure of any one party to meet a deadline will inevitably impact on others. In this respect, it would also be helpful if requests for additional information/ late changes to the FBPQ could be minimised.

There are still a significant number of policy issues that remain unresolved following the publication of the December 2008 policy paper and this has necessitated a number of assumptions being made when preparing the detailed business plan. Going forward we would welcome resolution of these issues as early as possible to reduce the degree of uncertainty and provide a firm basis on which to update the business plan for 2010-2015.

We welcome the additional consultation paper in May 2009 summarising Ofgem's cost assessment methodology. We continue to believe that the September update paper played a useful part in the process at previous reviews. We encourage Ofgem to consider some form of quantified statement on the key positions around September 2009.