



**Industry & Regulation**

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Friday 6<sup>th</sup> July, 2007

Attention: Andrew Neves  
Central Networks  
c/o [commercial@sppowersystems.com](mailto:commercial@sppowersystems.com)

Dear Andrew,

**Re: Structure of Electricity Distribution Charges – Joint consultation on the longer term charging framework**

Thank you for the opportunity to comment on the above consultation. Given the number of concurrent consultations in both gas and electricity at present, and the complexity involved, Centrica believes it would be helpful for all consultations, to have a minimum of an eight week consultation period and preferably twelve weeks unless a shorter period is mandatory.

We have some overall views which we will cover first, and we will then address some of the questions raised in the consultation document. We have elected not to respond to all questions, either because they are extremely technical in nature or because, in the time available, we have not been able to draw specific conclusions. As a general observation, as non-specialists in this area we did find the technical areas of the document very difficult to understand.

Centrica has continually pressed for illustrative impacts to be provided in this series of consultations around enduring structure of charges, and we welcome the fact that the G3 group has endeavoured to provide such illustrative charges. This is a helpful approach and we hope other DNOs will learn from this approach.

We acknowledge the caveats included in respect of the charges being indicative only and subject to further work, but we note with considerable concern, that the overall pattern is for Domestic unrestricted charges/smaller I&C charges to increase, in our view significantly, and for larger I&C charges including HV charges to decrease. There are some exceptions to this, but for the most part the pattern holds true. As a major domestic supplier, we believe that it is a matter for serious concern that the application of these methodology changes may result in a reasonably significant transfer of additional costs onto domestic customers. In our view, this is completely unacceptable. Given the group's comments that these indicative charges are very much a work in progress, we trust that this inequity will not persist into the final charges.

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In addition, whilst we acknowledge that frequent and detailed consultations have taken place, we are concerned that there is limited evidence that respondent's views have been fully taken into account, in particular, suppliers' repeated requests for transparency and predictability of the resulting charges.

Responses to questions from the document

**Chapter 3: Views are invited on the following:**

- 1) The different approaches to demand and generation.

Centrica considers it is reasonable to use a different approach for Demand and Generation, given the different impacts on the network. We also agree that the approach should not discourage the connection of generation where this can be achieved at zero cost.

- 2) Is analysis at the Network Group level appropriate?

Given the complexity involved, a degree of aggregation seems to be a reasonable approach, providing there is still adequate transparency and predictability of the end charges.

- 3) Is the approach of incrementing demands in 1% steps up to 15% and undertaking contingency analysis at each step reasonable?

Again, whilst not having sufficient technical expertise to fully evaluate the proposals, incrementing demand in steps and testing at each level is an established approach to assessing network requirements. The proposal seems reasonable, but we would welcome further information on the basis for concluding that 15% above current maxima is sufficient, and the confidence levels the group have around that conclusion.

- 4) Is one year of actual cost data sufficient to produce forecasts for HV and LV reinforcement costs?

As previously stated, Centrica is not expert in the forecasting of demand/costs on electricity networks, but we believe that one year's worth of data would normally be a very short period on which to base forecasts for future years. We would welcome clarity on the analysis that G3 has done to enable them to conclude that a single year's data is a sufficient and robust basis.

**Chapter 4: Views are invited on the following:**

- 1) The approaches to determining demand and generation marginal costs.

Whilst it seems logical that the identical approach cannot be used on both demand and generation for calculation of marginal costs given the different impacts the two have on the network and the generally lumpy nature of generation investment. We found the description of the approach on LV clearer and believe that this seems reasonable, including a small LV generation benefit in return for offsetting demand.

- 2) The time periods that should be used for determining costs.

No comment

- 3) Is the approach for determining growth rates, and particularly the method of adjusting for embedded generation to determine underlying demand growth, appropriate?

It is important that the methodology reflects the value of embedded generation to a local DNO as embedded generation can defer the need to reinforce the network to support the requirement for increasing demand. As stated below, we consider that the inclusion of negative charging in the methodology would reflect that value should be allowed. Negative Charging may also encourage siting of generation in areas that negates the requirement for reinforcement for future growth demand which will provide a benefit for all DUoS payers.

- 4) Is the 10 year time horizon for considering network reinforcements and the associated cost recovery period a reasonable approach?

Essentially, in our view, there are two key questions:

- a) when do you reinforce?
- b) What capacity do you install when you reinforce?

On the first, from a customer perspective, the investment should not be too early (or customers' money is spent before it is necessary) or too late. On the second, if too little capacity is installed, the DNOs will continually be carrying out small, probably inefficient, investments. If too much capacity is installed, again, customers' money is spent unnecessarily.

Whilst overall a 10 year (or possibly 10-15 year) time horizon for considering network reinforcements does not seem unreasonable, we believe that this is too short a period over which to recover costs. Centrica is of the view that the majority of costs should be recovered over the lifetime of the asset, whereas the document seems to suggest recovery in advance of the reinforcement.

As Distribution assets generally have a life of 40-50 years, then this would seem an appropriate timescale. Recovery "in advance" in this way, in our view equates to expensing capex, which we would not support in the case of capital investment. In turn, we believe that such a treatment of costs would place an unjustified burden on today's consumers.

- 5) Should the 10 year cost recovery period used for demand be used for generation also, or should the 15 years assumed for generation in the distribution price control be used instead?

As above, Centrica believes that a 10 year cost recovery for assets lasting c. 25 years is not acceptable as such costs should be recovered over the lifetime of the assets.

The approach to forward cost pricing includes two main elements. The first which seems sensible is that in the event there is more capacity available than the size of a typical generator the costs are assumed to be zero. The second element outlines what happens in the event that capacity is not available to meet the requirements of a 'typical generator' and in this case it is likely to trigger reinforcement costs and an inclusion in the forward price approach. If our understanding is correct the formula appears to build in an allowance for recovery of the costs associated with creating additional headroom. We are concerned in respect of the behavioural incentives this may provide, especially if forecasting future generation requirements is as difficult as suggested in the consultation document.

We believe that the effect of the proposal would be that the DNO would receive a return on this investment despite the uncertainty of whether the resulting capacity will be required by future new users. Clearly, given the nature of investment, there is an efficiency balancing act between merely undertaking sufficient reinforcement to meet the requirements of a new connectee and building redundancy into the system to meet future customer requirements. However, we are concerned that this approach could lead to the building of excess capacity in the system, giving a return on the investment for the DNO, which will need to be funded by customers. We are not clear how this risk is managed and how customers can best be protected from the additional costs which could be imposed.

- 6) Is the mechanism for determining charges in each of the time periods appropriate?
- 7) Should uniform generic values of the P2/6 contribution factors be assumed? If not, should they vary by type of generator or by region (taking account of the type of generator that is more likely to connect there)? Should actual contribution factors be determined from historical output data for existing generators where this is available? For lower voltage levels should voltage level averages be used?
- 8) Is the approach of using a typical generator size in determining the marginal cost appropriate?

When considering lower voltage networks, it would seem reasonable to base marginal costs on a typical generator, providing that enough data is available to be able to assess what a “typical” generator is in the circumstances. However, given the relatively limited number of generators connecting annually, and the apparent uncertainty around timing & location, we are not sure a methodology can produce robust estimates for marginal costs.

The document explains how a typical generator size is determined and the methodology for calculating this important factor seems broadly sensible. An enhancement to this calculation could include allocating a weighting to the three factors – previously connected generation, connections in progress and connection applications. We would suggest most weighting should be given to connections in progress as this should give the best insight into the future requirements of the networks, this seems to be borne out by the fact that the vast majority of new connections are connecting to the upper network.

- 9) Should the P2/6 based rules on the benefits arising from LV generation be relaxed for charging purposes?

#### **Chapter 5: Views are invited on the following:**

In addition to the questions raised in the consultation document, we are concerned about the approach used for some of the “other costs”. For example, forward looking estimates of Administration, Customer Service & Billing costs are used. These costs are converted into £/customer values for the main billing approaches/systems used by the DNO.

In our view this does not provide sufficient detail on the basis for allocation of these costs, however, if the allocation is carried out on a constant basis per customer, this would clearly be wrong. We would like to see detailed workings for how this allocation is carried out together with supporting evidence for the proportion of these costs allocated to each customer group. On the basis that this evidence has not been supplied, we do not support the approach contained in the consultation document. The same is true of pass through costs, again we consider that allocation of such costs on a constant £/customer or £/kVA basis is inappropriate.

- 1) Is one year of actual cost data sufficient to produce forecasts of operation and maintenance and refurbishment costs?

Centrica is of the view that a single year's data is insufficient to produce robust estimates of O&M and refurbishment costs. It is always possible that the year selected is atypical, either plus or minus, and on this basis, we would suggest a longer period be used to generate the forecasts.

- 2) Is the proposed revenue reconciliation approach of applying a different 'adder' to each voltage level in proportion to MEA value appropriate?

It was not clear from the document how the specific fixed adders have been generated and how the effects have been validated to ensure that they do not result in cross subsidies between customer groups. We do not agree that the revenue reconciliation approach should be applied in proportion to the MEA or solely on a per kVA basis. We believe that this is arbitrary and incorrect. In our view, the "other costs" referred to do not relate directly to MEA or capacity, and we believe that solely using capacity to allocate these costs will result in an over allocation to low voltage users and an under allocation to high voltage users. To produce an equitable result, we believe that the other costs should be allocated using a combination of volume and capacity.

We believe that there are concerns in using a "fixed adder" revenue reconciliation approach, particularly when the discrepancy between allowed revenues and modelled costs is large. In these cases, we believe that a fixed multiplier approach is likely to produce a more equitable and less distortionary effect.

- 3) Should negative charges be permitted?

It is important that the methodology reflects the value of embedded generation to a local DNO as embedded generation can defer the need to reinforce the network to support the requirement for increasing demand. The inclusion of negative charging in the methodology will reflect that value and therefore we believe that negative charging should be allowed to reflect that value. Negative Charging may also encourage siting of generation in areas that negates the requirement for reinforcement for future growth demand which will provide a benefit for all DUoS payers. Furthermore the concept of negative charging exists on Transmission charging so we see no reason why it should not exist at a lower level.

- 4) Would it be appropriate to cap site specific EHV charges at the level of the equivalent generic HV charges to avoid perverse incentives at the boundary and, if so, should this be done before or after allocation of sole use asset

costs to EHV charges?

We see no reason to cap site specific EHV charges at the level of generic HV ones. Whilst this approach might relieve the occasional perverse incentive at the boundary, we believe that the risk of cross subsidy developing as a result of the application of the cap would outweigh any minimal benefit gained.

**Chapter 6: Views are invited on the following:**

- 1) Where a single set of sole use assets support more than one metering point - for example import and export metering points sharing the same physical connection - how should the cost of these assets be shared?
- 2) Is the proposed approach to the sole use assets O&M charge set out in 6.1, or the alternative methodology set out in 6.2, more appropriate?
- 3) What should be the nominal life of sole use assets – should this align with the 10 years used for reinforcement, or mirror the expected asset life of, say, 40 years?

In common with our previous responses, we believe that the nominal life of the assets should mirror the expected asset life rather than a nominal 10 years, which has the effect (at best) of bringing forward costs to customers.

We trust these comments have been helpful and would be happy to help with any additional questions.

Yours sincerely,

Alison Russell