Your Ref: RBA/DPC/SOC/38/1

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Dear Mark

Consultation on Western Power Distribution's (WPD's) Modification Proposal to Change their Use of System Charging Methodology

EDF Energy welcomes the opportunity to respond to this consultation. This response is on behalf of EDF Energy as a whole, i.e. including its electricity generation and supply, and electricity distribution interests.

While we acknowledge the progress that WPD have made, we do not believe that the proposal better meets the relevant objectives set out in Standard Condition 4 of its distribution licences, and particularly objectives (b), (c) and (d) of paragraph 3 of that condition. On this basis, we do not believe that the Authority should give its consent to the proposals.

The main reasons for reaching this conclusion are summarised below, and are set out in detail in the attachment to this letter:

- WPD's use of a 1% average growth standard assumption undermines the cost reflectivity of the resulting marginal costs. If it is too complex to introduce different load growths for different nodes, then this would seem to call into question the value of introducing a complex methodology.

- The impacts of increments of demand or generation are in practice non-linear. Therefore, WPD's assumption of 0.1MVA increments with a linear impact will not create robust marginal price signals. This is clearly a major issue for the LRIC methodology, particularly in relation to generation, where the increments will tend to be non-marginal, perhaps resulting in costly reverse power flows at particular network nodes.

- WPD's use of simplistic tariff structures blunts the cost signals arising from the LRIC component of their methodology. The failure to offer "peak" unit charges or "triad" type demand charges undermines the benefits of a locational load flow signal and calls into question the value of having a complex methodology such as LRIC.

- Under WPD's proposal, EHV generators would be paid on the basis of capacity and not on the basis of actual support provided to the local network. This is a major (and probably fatal) weakness in the proposed methodology.

- WPD's load flow modelling assumes that network constraints occur only during two periods, summer minimum and winter peak. However, nodes will peak at other times – e.g. in areas where there are limited gas networks and where the electricity network constraint is at night (i.e. areas with a high penetration of electric storage heating). Furthermore, WPD has in excess of 50 Load Managed Areas in the South West, which indicates that inappropriate costs would inevitably be applied by the proposed methodology to these nodes in these areas.

- The proposed methodology does not detail how WPD will manage the enduring allocation of charges and payments. The current Distribution Generation Incentive is a mechanism to encourage network operators to invest efficiently in schemes that enable connection of distributed generation (DG). We believe that the corresponding DG allowed revenue should not be used as the method of balancing payments and charges amongst the DG connections. If there are benefits to be offered to DG, they will arise from a cost saving for demand users and so should be paid for by increasing the charges to demand users.

- A feature of the relevant economic signals is that they may produce volatile charges through the accurate reflection of cost. Charges should therefore be free to move as calculated and not capped, if the correct economic signal is being applied. The need to apply a cap indicates that there is a weakness or uncertainty in the economic signal. If the economic signal is not sufficiently accurate, or uncertainty remains, then it is unclear as to whether it is beneficial to introduce a more complex approach.

If you have any questions regarding this letter, please do not hesitate to contact Oliver Day on 01293 657920 or myself.

Yours sincerely

Denis Linford
Director of Regulation

Attachment

1% Average Growth Assumption

Concerns were raised in Ofgem's consultation paper about the assumed uniform 1% per annum load growth adopted by WPD. We agree that this assumption of a single load growth figure is unrealistic and its adoption is likely to undermine the cost reflectivity of the resulting marginal costs. A test of the affect of this assumption would be useful. The test could, for example, assume that a load growth of 2%, or some other growth rate, is known with certainty and then consider what the impact would be on cost reflectivity if instead a 1% growth rate is mistakenly used. In addition, if it is too complex to introduce different load growths for different nodes then this may call into question the value of the complex methodology.

It is also acknowledged that the use of an average load growth is a compromise, as the methodology does not work with zero or negative load growth. Further research is being conducted by the University of Bath to look at the implications of pricing for negative and zero load growth. We appreciate that it is difficult to judge the benefit of the early adoption of the approach against the missed opportunity which could arise by delaying introduction while further work is conducted. However, we believe that it would be in the network users' interests that some form of assessment be undertaken to ensure that inappropriate methodology changes are not carried out.

0.1 MVA marginal increments vs. non-marginal increments

The LRIC methodology is based on the calculation of costs resulting from standardised marginal (0.1 MVA) changes in load or generation. Strictly speaking, the resulting marginal costs are only correct for standard increments to load/generation and at the base level of load and generation. Cost functions are typically assumed to be linear around the base load and around small variations in load, thereby allowing adoption of standardised prices that can be used across the whole range of consumption variations.

However, the assumption that prices derived from small increments can be extrapolated to larger increments may lead to distorted signals**:**

- Firstly, losses and reactive power do not behave linearly with load so that the impact of a 1 MVA increment to demand will not be ten times the impact of a 0.1 MVA increment.

- Secondly, increments to demand or generation may result in either costs or benefits (i.e. reduced costs) because of the potential switch in the direction of power flows. The response of costs/benefits to large increments of demand/generation may not therefore be a multiple of the response to small increments.

- Changes of flow are more likely to occur with generation than with load. A 0.1 MVA increment to generation may, for example, be accommodated relatively easily within an existing network and may result in a negative marginal cost. However, a 20 MVA increment, for a modest sized generator, in the same network could result in the need for a major network Investment with reversal of flows and correspondingly high positive marginal costs.

This is, we believe, likely to be a major issue for the LRIC methodology, particularly for generation where the increments will tend to be non-marginal.

Strict cost-reflective pricing would require that prices are calculated for all (or at least a range of) increments proposed. While this will not be feasible for regular pricing analysis, it would be useful to consider the inaccuracies in cost reflectivity caused by using small standard increments and to consider whether a range of increments and/or decrements are needed and/or whether a single larger increment/decrement would more closely reflect marginal costs than the 0.1 MVA currently adopted in the WPD approach. We note that WPD's Paper refers to some testing of the model including an "examination of the impact of the size of the incremental injection". It would be interesting to see the results of these tests to see if the outcomes are substantially different for a 0.1 MVA increment versus other increments or decrements.

User Tariff Signals

We believe that where practical users should have a clear link between the pattern of their consumption and the marginal cost of using the network. Demand users' charges should be highest, and perhaps only charged, when the network is constrained. Similarly, generators should only be paid if they are supporting the network at times of demand constraint or charged if they are contributing at times of generation constraint.

WPD's use of simplistic tariffs does not reflect the cost reflective nature of the increased complexity of LRIC component of their methodology. This failure to offer "peak" unit charges or "Triad" type demand charges undermines the benefits of a locational load flow signal and calls into question the value of having a complex methodology such as LRIC.

Payments to generators and subsequent cross-charging

WPD's modification proposal and the corresponding charging statement conflict over what charge will be applied. It is unclear whether the charges will be capped or not. For example, on page 27 of the UOS002A modification proposal Chelson Generator has a capped charge of £5,829.23 yet on page 33 of the Statement of Charges (set2) for the South West the Chelson Generator charge shows a payment of 1.854 p/kVA/day. This multiplied by the 1.05MVA rating equates to a payment to the generator of £7,105.46 which allowing for rounding is the value shown on page 27 of the UOS002A modification proposal prior to capping (final charge).

We are concerned that the methodology does not detail how WPD will manage the enduring allocation of charges and payments. The current Distribution Generation Incentive is a mechanism to encourage network operators to invest efficiently in schemes that enable connection of distributed generation. We believe that the corresponding distributed generation (DG) allowed revenue should not be used as the method of balancing payments and charges amongst the DG connections. If there are benefits to be offered to DG they will be from a theoretical cost saving for demand users and should be paid for by increasing the charges to demand users.

It is clear that further consideration is needed to understand and set principles for where the money for generator payments should come from and how the maximum amount that should be paid out is calculated. The Ofgem sponsored Bath University study[1] suggested potential capital expenditure savings of £200m over 20 years if efficient economic charging is implemented (although the amount was disputed). At the very least, and only until further work is conducted, we believe that this offers a rationale for charging "extra" to demand users so that payments can be made to generators. Similarly, and if the methodology is cost reflective and not discriminatory against demand users, we believe that "extra" should be charged to generators so that payments can be made to the demand users who connect local to generation and avoid generation led capital expenditure.

If this issue is not tackled in a rationale or pragmatic manner it undermines the benefits of a locational signal and calls into question the value of having a complex methodology such as LRIC.

Network Constraint Times

Distribution constraints dictate when the network needs to be reinforced. WPD's load flow analyses assume that the distribution constraints occur either at winter peak when load and imports of electricity are at their highest, or at the summer trough when local demand is lowest and generation export is at its peak. This use of only two conditions may not be correct due to localised time dependencies of demand and generation.

For example, if wind generation is high during the winter and low during the summer then the period when a distribution node is constrained might shift to the autumn or spring. Similarly, storage heating, is likely to be highest between midnight and 5am rather than the traditional winter peak. Either of these examples cause localised reinforcement cost which are not reflected in the model.

If the constraint period occurs at times other than the winter peak or summer trough, then WPD's LRIC methodology would underestimate marginal costs.

Since wind generation is most dependent on external conditions (wind conditions) and since wind varies with season, this problem is likely to be most important for companies with high potential wind generation connection.

An assessment of the variation in electricity generation from distributed renewable generation sources, combined with an understanding of seasonal load patterns, should be able to confirm whether a two-period analysis is correct or whether more periods should be evaluated. If more

[1] Bath University - 2005

periods are necessary, this could potentially make the LRIC analysis considerably more complex.

Flip-flopping and the application of charge caps

Flip-flopping tariffs can occur when a low price encourages a generator or major consumer to a zone but as a result of the new generator or new major consumer there is a substantial change in distribution charges in the following year. In the worst case there could be a series of price changes and generator/consumer responses over time with a flip-flopping from positive to negative and back again.

This problem is linked, in part, to the issue raised concerning non-marginal increments to load or generation.

WPD proposes that prices charged for generators should not change by more than 10% per year. This would partially avoid the potential problem of flip-flopping for generators. WPD also proposes that potentially negative prices should be replaced with zero prices for load; this therefore dampens the location incentives to load customers and reduces the likelihood of flip-flopping. However, this is achieved at the expense of cost reflectivity.
It is difficult to predict to what extent flip-flopping of charges would occur but if it does occur it would send confusing signals to network users and would deter new network users, particularly generators. Conversely, the use of caps to deter flip-flopping undermines the location signals and calls into question the value of a complex methodology such as LRIC. To the extent that EDF Energy's network is the focus for considerable activity by generators, flip-flopping could be a particular problem for EDF Energy.

We believe it would be useful to understand**:**

- how often would marginal costs flip-flop if they were not dampened using caps,
- by how much would the location signals be dampened using these caps,
- what will be the likely impact by avoiding the more cost-reflective prices,
- are there alternative approaches to smoothing the transition of prices that better balances cost reflectivity with price stability.

To consider the problem that marginal costs might switch from positive to negative, we believe the analysis of marginal costs and corresponding prices requires further work.

Since marginal costs, prices and demand/generation location are interdependent, the stepping forward of the analysis would require a relatively complex analysis that describes the possible response of consumers/generators to the prices arising from the LRIC model and the feedback from these possible responses on LRIC prices. We note that generators in particular and, to a lesser extent, consumers are likely to base their location decisions on their expectations of future price movements as well as the immediate prices they face in the coming year. In the absence of indicative price projections published by WPD, generators are likely to make their own assessments of future price changes based on several factors, including the location responses of other market participants.

Location decisions are then likely to be very complex. Ideally, the analysis to test the likelihood and importance of flip-flopping would be iterative.

Reinforcement costs

The reinforcement costs adopted in the LRIC model are multiples of MEA value; for some assets WPD proposes a multiple of twice the MEA value. The assumed scale of the investment and the cost of the investment have a direct impact on marginal costs and are therefore key parameters. The scale of the investment should depend on the expected load growth. Further analysis is, we believe, required to understand how reinforcement investments historically relate to MEA values and to load growth expectations.

Differential revenue reconciliation adders

WPD proposes that revenue reconciliation adders (£/kVA) should be calculated separately for EHV and for lower voltages and that to do this the required revenue should be split according to MEA values of the assets of EHV and lower voltages. We currently feel that it may be more appropriate if a uniform £/kVA adder is calculated globally for EHV and lower voltages. Such an approach would preserve the absolute £ per kVA differences between location and voltage and hence send the correct signals to users of the network.

Fault level studies

The methodology ignores fault levels. This may be a serious omission for generation and its importance should be investigated. We recognise that this is an area where further work is in progress by Bath University.