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Dear Mark

Electricity distribution charging: Bath University benefit analysis work

I write with SSE's comments on the open letter and Bath University benefit analysis that Ofgem published on 13 January.

Bath University Study

Our detailed comments on the Bath University study are set out in the attached appendix. In summary, we are of the view that the Bath University analysis is too flawed for it to be used to support particular types of forward-looking charging models or to make judgements about the efficiency of DNO plans for reinforcement capital expenditure. Its greatest weakness is too simplistic an analysis of generator location decisions. As discussed in the appendix, we believe these decisions are not greatly affected by the type of charging model used. It follows that investment requirements would be little different between the different charging models and therefore that the key potential benefit for moving to more complex charging models claimed in the report would not be achieved. This implies that there is little justification in developing hugely complicated pricing models that increase uncertainty and risk for generators and customers. In our view, simple developments and enhancements to existing models are more appropriate.

The report itself contains caveats on the interpretation of its findings. In particular, the brief comments in the report on the level of future benefits being "potentially in the order of "£200m" are unsubstantiated and immediately followed by a caveat that any such extrapolation from the study work "would have little foundation". We are therefore extremely surprised that Ofgem has chosen to highlight this figure from the report.

In addition, we have the following comments on other matters relating to the Bath study.

Long Run Marginal Cost Models

1. Volatility, Instability and Sensitivity of Models

As Ofgem is aware, we have major concerns with any move towards introducing long run marginal cost (LRMC) based charging models into distribution. These models bring volatility and instability in charging for individual customers, as charges are driven by the decisions of other parties connected to the network. This instability is demonstrated in the Bath theoretical study and, furthermore, has led to actual problems and customer challenge in transmission charging, where such models have been introduced. This can be seen in the paragraph 83 in the report where the charge for node 5, for example, moves from £30 to £5 but can also be quantified with reference to the current transmission charging methodology.

In South Wales, generators currently get paid £2.50 per kW. NGET's seven-year statement shows a planned 2000MW power station for the area. When this is connected, the tariff in the area will change to a charge of £1 per kW. So the planned generator, instead of receiving £5m per year will actually pay £2m per year. This £7m swing in charges is a direct result of the proposed generator responding to the locational signal. It is also worth noting that the existing 4000MW of generation in the same area will have to pay the new charge meaning a swing of £14m because a new generator connects nearby. Furthermore, since the existing charge is negative, indicating an area with spare capacity for generation, these large changes in charges would not be accompanied by any actual investment in network assets.

The models are also very sensitive to the precise assumptions used to build up the charges. Two key parameters are the expansion constant (the incremental cost per MW per km of additional capacity) and the security factor (the adjustment for additional network to cater for unavailability of parts of the network). Both the Bath study and the recent consultation from Western Power Distribution (WPD) demonstrate the large number of other assumptions that need to be made to achieve a workable charging model. In essence, there are a large number of plausible ways of constructing the charging model and there is no “right” answer. Even the academics disagree on the “right” approach. This fact, coupled with the sensitivity of the output to the assumptions used, will in our view mean that it would be very difficult for such models to gain the legitimacy of general customer acceptance. With significant annual costs riding on modelling assumptions, we believe that individual customers who find themselves to be worse off with such charging structures will find it worthwhile to challenge such assumptions. Such a scenario brings its own additional uncertainties for the market.

There is not sufficient detail on the actual modelling presented in the Bath University report to illustrate the sensitivity of the distribution models discussed. However, an example of the level of uncertainty and volatility can be demonstrated by reference to the present model for transmission charging. The current charges are around £20/kW for generators in the north of Scotland. A large generator of 1000MW capacity therefore pays some £20m per year in network charges.

NGET has used expansion constant of about £10/MWkm in calculating these charges. However, work carried out by NERA suggests an expansion constant of around £6/kW could be justified. Using this expansion constant alone would reduce the tariff to £14/kW saving £6m per year.

NGET uses a security factor of 1.8 in its model. Since additional network is to provide security of supply (i.e. the security is for customers rather than generators) there is a strong argument to use a security factor of 1 for generators. Again this has a significant effect and would reduce generator tariffs in the north of Scotland to around £13/kW.

Combining the two effects (expansion constant of £6/MWkm and security factor of 1) would produce a tariff of £9/kW. The range of possible annual tariffs from this particular implementation of an LRMC-based approach for a 1000MW generator is therefore from £9m to £20m per year.

We also note that some DNOs recently proposed changes to their EHV methodology that resulted in significant price swings for individual customers. After customer representation and consultation, Ofgem capped any individual changes to the level of RPI increases. This demonstrates that regulatory intervention can still be required when "better" charging models are introduced.

2. <u>Connection Charge Boundary</u>
It is worth noting that the Bath study does not discuss the contribution made to cost reflectivity and locational signals from the connection charging policy, which is currently "shallowish". Connection and use of system charging should be considered together and it is important not to lose sight of the fact that it is not necessary for use of system charges alone to deliver cost-reflective, locational signals.

3. <u>Cost Reflectivity</u>
We also consider that the cost-reflectivity of the LRMC charging models is inferior to other approaches to setting charges. It is certainly arguable that basing charges on <u>notional</u> changes to a forecast of <u>future</u> costs is further from the "costs incurred by the licensee" (as required under the licence objectives) than, say, an allocation of <u>actual</u> costs. Future costs are entirely subjective and inherently unauditable, bringing a further source of uncertainty to the path of charges from year to year under this approach. A further issue on cost-reflectivity occurs where generators are to be credited with a perceived contribution to deferring reinforcement expenditure. Charges to demand customers actually increase to fund this credit, driving a further wedge between <u>actual</u> network costs and the basis of charging for particular groups of customers.

4. <u>Implications for Generation and Supply Markets</u>

A further detrimental effect of these models that needs to be considered, in our view, is that of the implications of the instability inherent in this charging approach on the generation and supply markets. In supply, more volatility and risk in use of system charging will lead to suppliers including a risk premium in their prices to end customers. Also, complex use of system charging methodologies, which require greater investment in suppliers' information and billing systems will bear more heavily on smaller suppliers, thus forming a barrier to entry and potentially damaging competition in this market.

For generators, we believe that the potential for instability in future use of system charging will make it more difficult for new generators to reach the hurdle rate for investment than under a scheme of charging which is known with greater certainty at the outset. This runs counter to the views expressed within government and also in Ofgem's draft corporate strategy and plan on the need for "a stable … regulatory environment" for generation investment. This view is expressed under Ofgem's comments on security of supply, as it is generally recognised that substantial investment in generation will be needed in the next decade for security of supply reasons, as well as to meet environmental targets which require investment specifically in renewable generation. From both perspectives, it is clear that unstable use of system charges from year to year will undermine the case for investment in generation.

There are specific, further issues for existing generation if this class of customer is also to be covered by distribution use of system charges in future. There would inevitably be a heightened perception of regulatory risk for the generation sector as a whole, if existing generators, which have been connected under previous arrangements that did not entail any ongoing use of system charges, are suddenly required to pay such charges. The question of the legal validity of imposing such charges should not be ignored and we believe that challenge from adversely affected parties is likely.

<u>Governance of the change process</u>

We continue to have concerns about Ofgem's role and locus in promoting particular types of economic charging models in electricity distribution. The electricity distribution licence obligations give DNOs, not Ofgem, the obligation to develop their charging methodologies. We support the open process that the Commercial Operations Group of the Energy Networks Association has put in place to develop a longer term framework for use of system charging and firmly believe that this process of dialogue with stakeholders should be allowed to run its course. It would be unfortunate if that process were to be compromised by regulatory edict and pressure on what the outcome should be.

<u>Conclusion</u>

We have discussed above some significant disadvantages of the LRMC approach to use of system charging arrangements. These include:

- Volatility and instability of the output charges from year to year;
- Sensitivity of output charges to the precise assumptions used;
- Inferior cost reflectivity of output charges; and
- Detrimental impact on supply and generation markets.

The Bath study has provided an interesting theoretical model, although we believe that the study outcomes are flawed as discussed in the appendix to this letter. We agree that it is appropriate for DNOs to consider the advantages and disadvantages of this study as part of their joint work on charging arrangements, along with WPD’s proposals and any other relevant academic work. Ultimately, it will be for each DNO individually, according to its licence obligations, to bring forward proposals for developing its use of system charging methodology. It is possible that these will not be the same for each DNO and in this respect, it is worth noting that there may be particular issues in the north of Scotland area. We will write with further thoughts on this subject.

We would hope therefore that Ofgem can support the joint DNO process and allow DNOs to continue to review and develop their methodologies according to their licence objectives and wider considerations of the implications of change for their customers.

I hope these and the attached comments are helpful in the continuing debate on this subject.

Yours sincerely

Rob McDonald
Director of Regulation

APPENDIX

Structure of Electricity Distribution Charges
Response to Bath University Study of December 2005

For ease of reference, we have grouped our comments under several headings.

Overall Approach

The study sets out an interesting concept in linking different use of system charging methodologies, via models of customer behaviour, with the longer-term investment needs of a “reference network”. While we understand the logic of this in principle, we believe that the study approach has serious flaws in practice. These include:

- Unsupported choice of EHV customer demand elasticity;
- Unrealistic modelling of response of distributed generation (DG) to price signals;
- Unrealistic extrapolation of reinforcement needs consequential to modelled customer behaviour; and
- No discussion of variability of output with assumptions.

We discuss each of these in turn below.

Demand Elasticity

The discussion of demand response models at paragraphs 56 to 62 discusses the available evidence on demand customer price elasticities. These are very small, being no greater than 0.03 in magnitude. However, the study uses a much larger figure of 0.5 for EHV customers without any justification and there is no discussion of the sensitivity of the modelling output to this figure. On the contrary, while transmission charges for demand have changed substantially with the move to a locational basis, we are not aware of any great demand-side response to these locational signals.

It is worth noting the comment in the report at paragraph 61 the “the small values of these [non-EHV] price elasticities means that little differential response can be expected from these customer groups as a result of applying each of the pricing approaches.” Thus, the conclusion can be drawn that low price elasticities from the demand side imply that there is no particular benefit in applying cost signals through use of system charges to this group of customers. No evidence is presented that EHV customers are any different and the same conclusion might apply to these customers as well. At the very least, this conclusion calls into question the rationale for seeking to introduce complex use of system charging models for any demand customers.

DG Response to Price Signals

This part of the model is particularly weak.

The model assumes an overall economic "best choice" location for generation but it does not appear that parameters other than the use of system charge can be varied. This means in effect that the sole "rational locational choice" for generation is determined by the network charge. Paragraph 85 reinforces this and states that "In the case of the LRIC-DC model generation is attracted exclusively to the highly loaded nodes 1, 3, and 5 in the urban area."

This is simply unrealistic. Two types of generation are identified in the model – CHP and wind. Three distribution areas are modelled: an urban area, an industrial area and a rural area. It is therefore clear that other constraints in generation location need to be included in the model since in practice, wind generation is bound to locate in a rural area; domestic CHP will locate (by definition) in an urban area; and larger industrial scale CHP would be expected to locate in industrial areas since the requirement for heat is to support industrial processes.

We believe that, even with the highly locational charging arrangements in transmission charging for generators, there is little evidence that actual use of system charges are a major factor in generator location. In our experience generator location is driven by other factors, principally the availability of resource, the ease of obtaining planning consent, the proximity to a network connection and the requirement for process heat in the case of CHP. All other things being equal, the potential network charges might influence the locational decision but this is, in our view, very much a second order effect.

In common with the demand side, therefore, effective generator elasticity with respect to use of system charges is, in our view, also very low and we believe this would be demonstrated if the model allowed the additional, practical constraints on generation to be included. It follows that there would be little difference in the investment requirements between the different charging models and therefore the key potential benefit identified in the report would not be achieved.

<u>Extrapolation of network investment needs</u>
It is also not credible, even if DG <u>did</u> locate in the urban areas, as the Bath study finds to be the case where LRIC charging models are used, that there would be "no investment needed to accommodate the growth in demand" at these nodes, as claimed at paragraph 98. A DNO has to secure demand according to P2/5 (which is expected to be replaced in due course by P2/6) and in practice, DG has currently only limited benefits with respect to security of supply. These benefits might increase over many years as DG becomes established but in the foreseeable future it is in our view likely that additional reinforcement to cater for increased fault levels will be required.

As demand grows at network nodes, some network reinforcement is bound to be necessary and individual network characteristics will determine how much is required. Dwelling on the combination of generator response and the above flawed assumption on required reinforcement for the apparent "out-performance" of the LRIC models compared to other charging models undermines the credibility of the whole study and its conclusions, in our view.

<u>Variability of Model with Assumptions</u>
There are many assumptions in the modelling and it is not clear how the output of the model would vary if the assumptions were varied. Some have already been mentioned (demand elasticities, DG location decisions, quantum of network investment needed) but others include interaction between the precise assumptions on the background investment programme needed and the increment to this represented by the growth assumptions used; and the effect of the reference network chosen.

<u>Other Comments</u>

In addition to the perceived flaws in the modelling approach discussed above, there are other issues with the output of the modelling, which are worth noting and we comment on these below.

- In the conclusion section of the report, the benefits of the LRIC approach are assessed at £830k. This is then extrapolated without explanation to savings in the region of £200m across the GB system. This claim is then followed by the comment that “such an extrapolation would have little foundation since the reference network is not necessarily typical of extant distribution systems”. We would go further and note that the simplifications and flaws in the modelling approach make it very unlikely that any material savings would be achieved if LRIC models or any other LRMC-based approach were to be used.

- Both the forward-looking approaches considered in the Bath study demonstrate the instability in charging that we believe is inherent in these types of models. For example, paragraphs 75, 76, and 80 comment on the instability in charging demonstrated at some nodes under the ICRP approach. Similarly, paragraph 44 hints at exponentially rising prices at some nodes under the LRIC approach. As well as being an undesirable feature of a charging model per se, we believe that instability itself may affect customers’ behaviour. Customers will have to consider the long-term outlook for use of system charges when making their siting decisions not just the current combination of connection and use of system charge, as implied in the Bath study, which may feed back into the customer behaviour part of the modelling.