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Date: 4 July 2011

Dear Ynon

Consultation response – Electricity distribution charging methodologies: DNOs' proposals for the higher voltages

CE Electric UK Funding Company (CE) is the UK parent company of Northern Electric Distribution Ltd (NEDL) and Yorkshire Electricity Distribution plc (YEDL).

Thank you for the opportunity to comment on the consultation. We note and welcome Ofgem's initial assessment that the submitted extra-high-voltage distribution charging methodology (EDCM) proposals are a substantial improvement on current methodologies and that the methodology largely meets the objectives set out for the project: we are encouraged by this statement and welcome the opportunity to provide further comments.

We summarise our views below and provide answers to specific questions in appendix 1.

We believe that in the round we have delivered a methodology that, whilst not perfect, provides a good base-line for setting use of system (UoS) charges for both demand and generation connections at the highest voltages. We do, however, recognise the inevitability that, as with any change of methodology, some customers will be more affected than others.

The new methodology provides commonality and, given that one of the big challenges has been to move from numerous different DNO methodologies all with very different starting positions to one common methodology, we believe this is a significant step forward and will be of benefit to most stakeholders – in particular suppliers and licensed distribution network operators (LDNOs).

With regard to the areas of either potential conditions or further improvements, CE is actively working with Ofgem and other DNOs to carry out some initial investigation into these issues and assess the feasibility of implementing these changes without the need to consult with stakeholders. We are hopeful that we can reach agreement on some of the areas that can be addressed relatively quickly and without significant impact, but feel that there are some areas particularly in respect of the calculation of network use factors that can have significant impact on charges and would therefore warrant further consultation before implementation.

Our preference would be to see the consultation approved without conditions, but we accept that approval with conditions may be the only option given the significance of some of the changes. This would then pave the way for proposals to change the methodology to be managed under the distribution connection and use of system agreement (DCUSA), in an open and transparent way ensuring full stakeholder input. The change in methodology will in itself introduce disturbance, and it would therefore be beneficial to have a period of stability to ensure that end-users are able to respond to the charging signals. We should if possible avoid being in the same position as we are with the CDCM, where we already have a significant number of changes either in the pipeline or being proposed, some of which could have a significant impact on end-user charges.

We recognise that volatility is a concern to all stakeholders, and agree that there should be a review of the elements that could be smoothed over time. Volatile data inputs that may relate to exceptional single years of data may impair the cost reflectivity of the resultant tariffs. One of the big differences between the CDCM and the EDCM is the principle of average tariffs as opposed to site-specific tariffs. It will therefore be more difficult to smooth EDCM inputs without eroding the cost signals we are looking to give. We believe it is more appropriate for DNOs to help end-users to manage their sites by looking at the feasibility of reducing their consumption at system peak or by reducing the level of capacity they reserve on the network – resulting in less reinforcement cost over time. These signals are currently being delivered through the methodology and, provided they are passed on to end-users via their supplier, they have an opportunity to manage their UoS charges to some extent.

In terms of the phasing question we have responded separately and concluded that, given the amount of work involved to get the methodology to this stage, full implementation on 1 April 2012 would be our preferred option. We see no case for phasing as this brings into question what alternative methodology would be used to phase the charges and on what basis that charge would be allocated. We do not believe it would be possible to construct a cost-reflective phasing methodology in the time we have available prior to the implementation date.

If, however, Ofgem believes that those end-users who will see significant increases need more time to respond to these signals, there may be a case to delay implementation, but it is our firm view that, if there is to be delay, implementation should be put back to the start of the next price control period to provide a reasonable amount of time for those end-users to respond.

We trust this helps in your decision-making process: however, if you would like to discuss any aspect of this response further please contact me.

Yours sincerely

H Jones

Harvey Jones
Head of Network Trading

Appendix 1 – Specific questions and answers

Question No	Question	Response
2.1	What are your views on the key issues with the methodology we have highlighted? Are there any other issues or concerns with the methodology as a whole that we should consider?	Many of the issues raised in the consultation have already been identified and discussed in detail by the working groups. In order to address these, DNOs have already started to review the issues identified in order to better understand the scope of any work required and the feasibility of implementation within the timescales. When DNOs submitted the proposal we believed it would meet the licence requirements and deliver significant benefits when compared with the numerous existing methodologies. We also recognise that the methodology will develop over time via the open governance process. However, we believe that the decision on the definition of sole-use assets should be revisited. The definition for sole-use assets in the EDCM is based on a technical assessment of the load-flow rather than the commercial boundary of connection. In some circumstances this technical basis can in effect ignore the payment made by the customer in connecting to the network and impose a use of system charge on that customer for those assets. We believe that those customers (whilst this is rare) will see this as inequitable and perhaps as paying twice for the same asset, once for connection and once for use of system. We have tried during the project to raise this issue but we could not gain consensus to make the change. During the project it was agreed that, once the Ofgem policy on the application of pre-2005 DG compensation was clear, we would review the proposals (consistent with the Ofgem decision) to accommodate the charges for shared and sole-use assets which are currently excluded from the methodology. We note Ofgem's consultation is silent on this issue.
2.2	Should we approve the methodology, do you agree with our proposal to implement it in full from 1 April 2012? If not, why is phasing-in charges or delaying implementation appropriate?	We believe the methodology should be implemented in April 2012 as planned, in order to realise the benefits. If delayed it should be put back to the start of the next price control period. We are opposed to any phasing as this would be very difficult to implement and manage, would introduce cross-subsidy issues and, given the project has already been delayed, would not be welcomed by the industry as a whole. From a CE perspective the overall conclusion we have drawn is that, whilst the EDCM has brought some change to the EHV charges in terms of outliers for demand, it is producing no worse a level of outliers than our current methodology and is overall more cost reflective. In the generation charges there is a much stronger correlation between agreed capacity and charge such that, whilst there are some customers who are paying a large charge, it is (at least) in proportion to the size of their agreed capacity and nature of the network they are connected to.
3.1	Do you agree with our assessment that the approach for the revenue target is reasonable?	We agree with this approach
3.2	Do you think the principle the maximum import capacity is a cost driver at the voltage of connection is reasonable for charging purposes?	We agree with this approach

Question No	Question	Response
3.3	Do you agree with our view that reactive power flows should be incorporated as part of the capacity that attracts indirect costs and 20 per cent of the residual?	We agree that there is potential within the model to include reactive power flows in the calculation to address this. The working group is already looking at a potential solution, which will result in additional input data for LRIC companies and changes to the EDCM model. The materiality of this change will be discussed with Ofgem.
3.4,3.5 & 3.6	3.4 Is it appropriate to consider the specific assets the customer uses for the calculation of the customer's charge, or would it be more appropriate to consider only the voltage levels the customer uses for the calculation of its charges? 3.5 Do you think that the 'spare capacity' issue we identify should be addressed? 3.6 Do you think notional asset values should take into account assets below the customer's voltage of connection?	The development of network use factors (NUFs) was introduced very close to the submission in December 2010. It was deemed that this approximation would on the whole reflect the assets utilised by customers, but was derived from load-flows. Ofgem's alternative suggested in paragraphs 2.81-3.91 is to use capacity as the denominator, but the initial view is that this would cause big changes in customers' prices. In our discussions with Ofgem and independent advisers it became clear during the project that competition law requirements for cost reflectivity supersede other requirements. We therefore believe that the site-specific route is appropriate as it ensures a more cost-reflective outcome. The working group are considering other options, such as applying a utilisation factor, to address the issue of spare capacity. We agree that in some circumstances it may be appropriate for assets below the voltage of connection to be taken into account and this is now being addressed by the group. We would, however, point out that any changes to NUFs could have significant impact on customers' charges and therefore implementation should only be considered after a detailed assessment has taken place. We believe the 15 distribution points of common coupling (DPCC) evolved to give a much greater level of granularity and are therefore more cost reflective. The reference to inconsistency between the DPCCs and the NUFs has been addressed by the group and validated by DNOs. The cross-checks between these two factors provide useful validation that charges for the correct voltages are applied.
3.7	Are there any other demand-specific issues that you think we should consider as part of our decision?	See our response to 2.1 with regard to sole-use assets
4.1	Do you agree with our proposal to modify the generation revenue target in order to avoid double charging for operations and maintenance costs on sole-use assets? This issue aside, do you agree with our view that the approach to calculating a generation revenue target is reasonable?	We agree that there is a potential double counting and the formula will be amended to reflect this.
4.2	Do you agree with our assessment that the approach to scaling is reasonable?	We agree that the different approaches for demand and generation scaling are appropriate for a demand-dominated network.

Question No	Question	Response
4.3	Do you think it is appropriate for only units exported by non-intermittent generators during the super-red time band to be eligible for credits?	This is appropriate as it reflects the benefit that non-intermittent generation can bring to avoid reinforcement costs at peak times.
4.4	Do you agree with our proposal that intermittent DG should be eligible for credits as they are deemed to provide network benefits under ER P2/6? If they do become eligible for credits, should the credits only relate to units exported during the super-red time band or is a single credit rate to all units exported more appropriate?	The reference to the P2/6 planning standard, if taken literally, supports the rationale for not applying credits to intermittent generators as they cannot be relied upon for network planning. Whilst there may be lots of generation capable of providing support, it is not contracted or recognised by P2/6. When assessing a demand group generators are assessed individually and not as a whole. Therefore we do not agree with Ofgem's proposal to apply credits based on the remote element of the LRIC/FCP charge. If Ofgem believes that we should introduce credits to non-intermittent generation then we shall need to look for a rationale that links loosely to the planning standards. These types of generator do not defer any costs and so any credit could not claim to be cost reflective but would be more a recognition of encouraging DG to connect. The group are currently looking at alternative options and will discuss these with Ofgem in due course.
4.5	On import charges for generation dominated mixed import-export: • Do you agree with our suggested alternative to using the collar of the network use factor for the calculation of the import tariff? • Do you think that the methodology is appropriate for demand customers connected to generation dominated assets?	This issue is being looked at by the working group and could be linked to issue 5. The NUFs are already capped to ensure that, where a site has both demand and generation, excessive NUFs are not applied in the calculation of the import charge. The suggestions made in the consultation may benefit some sites, particularly if the NUF were set to zero at the level of connection, and therefore may merit further investigation. The issue of a small demand site being located next to a large generator may not be quite so straight forward. The review of the derivation and application of the NUFs introduces a further level of volatility that may well be justified once the analysis has been concluded.
4.6	Are there any other generation specific issues that you think we should consider as part of our decision?	See our response to 2.1 with regard to sole-use assets
5.1 & 5.2	Do you agree when calculating LDNO charges that DNO costs upstream and downstream of the point of connection should be considered? Do you think that DNOs should provide LDNOs with a discount on all non-asset based charges?	The application of 50% discount to indirect costs for LDNO tariffs recognises that LDNOs also have some indirect costs to recover, and it would therefore seem appropriate that the same discount should be applied to the 20% scaling which is also applied as a capacity charge as this cannot be linked directly to assets.
5.3	Do you think that varying LDNO discounts only with the point of connection will better achieve a balance between reflecting upstream and downstream	The application of LDNO discounts in line with the 15 levels of DPCC is cost reflective and therefore we would argue that it is appropriate. However, we do recognise that for LDNOs this could provide a perverse incentive for gaming to connect sites that attract bigger discounts because of the configuration of the upstream assets. We would find it difficult to argue against a transparent cost-reflective signal and therefore believe the 15

Question No	Question	Response
	costs?	levels should be retained.
5.4	Do you agree that it may be appropriate in some circumstances for the DNO to pay LDNOs use of system credits?	The rationale for applying the 100 per cent cap was that applying a greater than 100% discount would mean giving credits to LDNOs and this did not seem to be appropriate as this relates specifically to incentives that DNOs can either perform well or badly against when managing their networks. We think capping any discount to 100% brings this in line with the principle applied in the demand methodology, which does not apply credits to demand customers because the networks are primarily demand dominated.
6.1	Do you think sole-use assets should attract scaling 'costs' to the same extent as shared assets? Does the charging rate on sole-use assets seem reasonable given the nature of these assets?	We believe that the treatment of sole-use assets as a whole should be looked at in more detail under open governance. There are some instances where sole-use assets that were paid for in the past are now treated as shared use due to the introduction of the definition of sole-use assets in relation to the point of common coupling. With regard to scaling the methodology does not explicitly detail what is included in the scaling charge. It is generally accepted that this is a mechanism for DNOs to recover their allowed revenue, which is not all related directly to assets and cannot therefore be allocated. One of the specific elements not allocated is the amount that should cover replacement of assets. If replacement costs were factored in then it would be appropriate to scale the sole-use asset charges in the same way as other network assets.
6.2	Do you agree with our view that the arrangements for demand- and generation-side management agreements are appropriate? Do you think such agreements should be available to all customers?	DSM/GSM agreements should not be seen as an incentive, they are meant to reflect the avoidance of cost in heavily loaded areas. High LRIC/FCP charges are likely to reflect the need for these types of contract. If there is significant spare capacity then there is no benefit to either the DNO or the customer and DSM/GSM should therefore not be considered. The detail of these agreements is currently being worked up and it is imperative that all parties involved are clear on the benefits that are linked to these.
6.3	Do you agree with our assessment that an explicit reactive power charge is not appropriate?	We agree with this principle as the load-flow already takes account of a customer's power factor.
6.4	On the proposal for sense checking branch incremental costs in LRIC: • Do you agree with our view that positive cost recovery (i.e. charges) and negative cost recovery (i.e. credits) should be considered separately? • Do you consider that recovery from demand customers and recovery from generation customers should be considered separately?	We feel that it may be appropriate to consider positive and negative cost recovery separately: however, it should be recognised that this is a significant piece of work and the magnitude of change cannot be assessed until the detailed analysis has been carried out.

Question No	Question	Response
6.4 but think it should be 6.5	Do you think the EDCM should include a mechanism to mitigate the potential volatility from network use factors? We welcome views on measures to mitigate volatility and help customers manage volatility.	We recognise that volatility is a concern to all stakeholders, and agree that there should be a review of the elements that could be smoothed over time. Volatile data inputs that may relate to exceptional single years of data may impair the cost reflectivity of the resultant tariffs. A change proposal is currently progressing though DCUSA to address smoothing the annual volatility surrounding inputs to the CDCM by using a three-year rolling average to ensure that trends over time are captured. The big difference between the CDCM and the EDCM is the principle of average tariffs as opposed to site-specific tariffs. It will therefore be more difficult to smooth EDCM inputs without eroding the cost signals we are looking to give. We believe it is more appropriate for DNOs to help customers to manage their sites by looking at the feasibility of reducing their consumption at system peak or by reducing the level of capacity they reserve on the network – resulting in less reinforcement cost over time. These signals are currently being delivered through the methodology. With respect to smoothing NUFs in particular this would definitely delay any benefits due to customers but on balance it could provide some level of stability.