CE Electric UK

Your Ref: 104/08

Our Ref:

98 Aketon Road
Castleford
WF10 5DS
Tel : 01977 605912
Fax : 01977 605858
e-mail: Harvey.jones@ce-electricuk.com

Lewis Hodgart
Distribution Policy
The Office of Gas and Electricity Markets
9 Millbank
LONDON
SW1P 3GE

19 August 2008

Dear Lewis

Re: Delivering the electricity distribution structure of charges (SoC) project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements

I am writing on behalf of CE Electric UK (CE) Funding Company and its wholly owned electricity distribution licensees Northern Electric Distribution Limited (NEDL) and Yorkshire Electricity Distribution plc (YEDL). This letter provides our response to Ofgem's recent decision and consultation on delivering the structure of charges (SoC) project.

I should say at the outset that we welcome Ofgem's stance in taking the lead in the future direction of the structure of distribution use of system charges (SoC) project. We recognise the amount of work that has already been put in by Ofgem, industry stakeholders and all distribution network operators (DNOs) in this area and are committed to working together to progress a common approach to charging that can be utilised by all DNOs.

What is immediately clear from Ofgem's decision and subsequent consultation is that we may need to significantly change the focus of our long-term charging project. At this point it is not clear what impact on resource this will have or indeed how much of our investment will result in abortive cost. We would expect that the full impact on us should become clearer as Ofgem publishes its preferred approach.

Irrespective of the outcome of the current consultation, it remains our intention to develop revised charging methodologies for NEDL and YEDL that will meet Ofgem's requirements by October 2009 (for implementation by April 2010). We had planned to consult with customers in September: however, following the express request from Ofgem and not wishing to confuse customers, we are putting the consultation process on hold pending Ofgem's decision. We are however, ready and willing to work with Ofgem on any aspect of the proposals (including the drafting of an appropriate licence modification) if that would be helpful.

We believe there is a great deal of merit in Ofgem specifying a common charging methodology to be applied across all DNOs. From both Ofgem's and an industry perspective we can see that it could reduce the overall development cost within the industry, though of course not to the extent that it would if this decision had been made earlier. It is vital not only that we have a common set of rules/principles, but also that we have a common charging model, if any subsequent governance arrangements are to be successful. It is essential that, when Ofgem decides on the model to be used, it should also specify the approach to be used. The detail and precision specified should be at such a level as to leave no scope for further discussion or differing interpretation.

With respect to the timetable put forward by Ofgem, whilst we think this is quite challenging we feel it is a sensible approach and achievable, provided that all of the following are achieved in sufficient detail prior to having to accept the licence modification:

- The licence drafting workgroup concludes by the end of August;
- Ofgem decides on the model to be used as early as possible in September; and
- Ofgem is very prescriptive concerning the model and approach to be used.

In relation to the governance of the charging methodology, Ofgem states that it will consider responses prior to concluding whether DNO governance arrangements should be ‘fast-tracked’ as part of the structure of charges project or whether they will continue to be taken forward as part of the wider review of industry governance arrangements. It would seem sensible to include distribution charging methodologies in the overall governance review in order to ensure consistency of approach across the industry. On August 5 Ofgem published an invitation to the industry to join a Code Administrators’ working group looking at convergence and simplification of code modification processes. The first consultation is due to be published in August consideration could be given to extending this group to include representation from distributors.

In the consultation paper a number of specific questions are posed, and appendix 1 details our response to take each of these points in turn. We have also added details of the process we went through in deciding which charging methodology we would develop and why – we hope this is of help to Ofgem in coming to a decision.

As well as developing methodologies to better meet the relevant objectives under SLC13, Ofgem and the DNOs have identified a set of high-level principles for the project. These principles are: cost reflectivity, simplicity (at point of use), transparency, predictability and facilitation of competition. Following the April 2008 consultation document and recent discussions between DNOs and Ofgem these principles have been developed further. A high-level assessment of how the work that CE is currently undertaking (LRIC development at EHV and its subsequent integration into a DRM-type model for charges at lower voltages) measures up against the newly developed relevant principles is set out in appendix 2.

In summary, we welcome the stance that Ofgem is now taking in leading the future direction of the long-term charging arrangements, but we shall only truly be able to say whether such an approach is acceptable to us once we have seen the exact licence modification drafting.

I trust this response sets out our views sufficiently and would stress again that we would welcome the opportunity to discuss these views with you. We would also be willing to participate in any groups that are established to take forward developments in this area.

Yours sincerely

H Jones

Harvey Jones

Head of Network Trading

Appendix 1 - Detailed response to specific questions in the consultation

Whether respondents agree that Ofgem should specify the common methodology to be applied across DNOs

We believe there is a great deal of merit in Ofgem specifying a common charging methodology to be applied across all DNOs. From both Ofgem's and an industry perspective we can see advantages in such an approach, specifically in terms of reducing the overall development cost and approval overhead within the industry - although we do have a concern that any subsequent governance process will need to have the right checks and balances to ensure that changes are vetted before consideration on an overall cost/benefit basis.

We still believe that the approach outlined in the consultation paper has the potential to delay the implementation of cost-reflective charges for demand and generation customers because it may make it less likely that we can use the work that we have already done to develop our revised charging structures – certainly further work will be required.

It is essential that when Ofgem decides on the model to be used, it should also specify the approach to be used. The detail and precision specified should be at such a level as to leave no scope for further discussion or differing interpretation.

With respect to the timetable put forward by Ofgem, whilst we think this is quite challenging we feel it is a sensible approach and achievable, provided that all of the following are achieved in sufficient detail prior to DNOS having to accept the licence modification:

- The licence drafting workgroup concludes by the end of August;
- Ofgem decides on the model to be used as early as possible in September; and
- Ofgem is very prescriptive concerning the model and approach to be used.

In the past we have expressed concern about Ofgem's previous track record in being rather opaque in its statements on this topic and not providing clear guidance on the direction that DNOs should be following. With this in mind we welcome Ofgem's move to specify the common methodology, at all voltage levels, to be applied to all DNOs. In fact we think that, if Ofgem had taken such a stance earlier in the process, we would not be up against the exigent deadlines that we now face. In respect of the detailed mechanics of specifying a common methodology, Ofgem may also wish to provide the model template that it wishes DNOs to adopt as this would aid the establishment of more robust and workable governance arrangements.

CE's evaluation of the relative merits of the potential charging methodologies

During 2006, when considering the route CE Electric might wish to take, we visited many of the DNOs that were developing different approaches for long-term charging and discussed with them the position they had taken on the charging models. Following this exercise we formed a view of what would be involved if we decided to go down a similar route to that taken by any of the other DNOs.

Long-run incremental cost (LRIC) modelling

We considered the work that the University of Bath (UoB) had carried out for both Ofgem and then for Western Power Distribution (WPD) and concluded that this approach was much more developed as WPD were looking to put forward their proposals for implementation in April 2007 – it also appeared to send the purest economic cost signals. We decided that, in terms of the degree of work already undertaken and the extensive consultation carried out by WPD, they were the front-runners in terms of addressing the licence objective and high-level principles that Ofgem was looking for (i.e. an approach that accurately reflects forward-looking costs; incentivises efficient usage and development of the network; and accommodates the introduction of generator use of system charges (GDUoS) better than the current models).

In addition we contacted the UoB and established that, since working with WPD, they had continued improving the long-run incremental cost model (LRIC) approach and addressed some of the issues that Ofgem had expressed as concerns. We felt that, if we could continue to address these concerns working with the UoB and consulting with WPD where appropriate, we could improve the work already carried out and help to establish a more robust methodology. In terms of timescales we believe we could have been ready for an implementation in either April or October 2009.

Forward-cost pricing (FCP)

The reason we did not adopt the Scottish Power (G3[1]) approach was primarily driven by the additional cost and labour intensity, particularly with respect to engineering resource – if Ofgem were to adopt this approach we would have major difficulty in obtaining the right level and calibre of resource to complete the project within the proposed timescales. We do not currently design detailed schemes for projects until much closer to the implementation date, and feel the additional resource required to carry out this activity would far outweigh any potential benefits. There are many other factors which may change over time that also mean a scheme may not go ahead or be implemented as initially planned, such as:

- on-site conditions and permissions affecting the design;
- the need for additional asset replacement; and
- the requirement for reinforcement - a high-level assessment has shown that we can expect around 30% churn (additional projects coming in and existing fully designed projects not being required) across the life of a 10-year plan. Whilst this does not remove the need for total investment, it underlines the folly of investing in full designs in the early years of the plan.

Our concerns regarding the G3 approach were not only based on the cost and resource issues, but also the time it would take to get up to speed with the actual network data requirements. We currently operate different modelling tools in each of our licence areas and we needed to understand the engineering resource implications for setting up new models to accommodate the outputs from each of these programmes.

We were also involved in some of the development work on the commercial operations group (COG) model, but had already invested considerable time, effort and resource updating the existing DRM model which was approved by Ofgem in October 2006. Alongside this we have developed our thinking on how the distribution reinforcement model (DRM) could be adapted to provide generation charges at high voltage (HV) and low voltage (LV).

At lower voltages the use of capital costs from historical data in the regulatory reporting pack (RRP) appears to fail based on its use of retrospective data rather than being forward looking, which we believe to be a key principle of any methodology. Whilst this data may be appropriate for operating costs that vary little year-on-year, it does not seem suitable for the more volatile capital cost. For this reason we decided that we would stay with the DRM and look at a new approach for customers connected at extra high voltage (EHV) only.

Whilst the G3 approach had the advantage of linking back to the investment planning process, it would have meant us relinquishing the extensive work we had done in updating the DRM and move to the COG model.

Modified LRIC

The Electricity North West (ENW), approach was still in the early days of development and it was not possible at that stage to assess the potential costs.

Following our investigations, we concluded that there was currently no perfect solution available, and the reason we went down the LRIC approach was primarily driven by the fact that during the extensive consultation process many of the issues had been debated and addressed. The UoB had already carried out work for Ofgem and WPD and were actively seeking to address some of the outstanding issues, through their research group. The

[1] The G3 are made up of Scottish Power, Central Networks and Scottish and Southern energy

methodology as it currently stood had capacity for further development (i.e. to include such as fault level contribution and the benefits of micro-generation at lower voltage levels) and this was an important consideration in terms of establishing a platform for future development, especially given the licence requirement to review charges at least annually.

In terms of implementation timescales, we concluded that all the approaches would require between 12 and 18 months' implementation time, with a dedicated team.

Ofgem pros, cons and impacts of each model

We are working on the assumption that Ofgem is still happy with the existing arrangements whereby the industry implements site-specific locational charges at EHV and average charges further down the network (i.e. for HV and LV connected customers). As Ofgem itself notes in the consultation, any methodology is required to achieve the relevant principles - this requires the industry to find an appropriate balance of objectives that may pull in different directions. It is not clear to us how much weight Ofgem will put on each of the principles, so we are therefore unable to assess with confidence how Ofgem might balance these competing objectives in making its own assessment of the methodologies. It is worth noting that, in our view, there is currently no perfect solution available and the methodologies that have been developed so far need to be measured as to which best meets the majority of the defined principles; any model will need to be further developed in the longer term.

At EHV we believe that the LRIC model approach is the best methodology to adopt as it most closely aligns to, and provides a pragmatic balance of, the principles that have been developed to underpin the SoC project and provides the purest economic signals. In fact we believe that in Ofgem's pros and cons analysis it under-states the level of industry support for this approach. It has already been implemented in two distribution services areas (DSAs) and it is also being developed in a further five DSAs (CE x 2 and EDF x 3).

In addition, we believe that our own ongoing development work in this area, in conjunction with the UoB, has addressed (or at least mitigated) a number of the concerns raised by Ofgem – specifically:

- the use of published information - the CE approach uses information from the long-term development statements (LTDS); and
- the sharply disproportionate signals that result from low growth rates on highly utilised circuits.

It is also worth noting that this approach is flexible enough to support future developments and extensions to the mechanism, some of which have already been identified by the UoB.

In contrast the forward-cost pricing (FCP) approach appears to fail to meet a number of the key principles. For example:

- the approaches for demand and generation charges are inconsistent, thereby distorting the cost signals between demand and generation;
- it does not appear to reflect all cost drivers as future reinforcement is not considered unless the utilisation of a circuit exceeds 87% of its rated capacity - such an approach is likely to add instability to the charges and reduce predictability;
- throughout the structure of charges (SoC) process it has been recognised that averaging charges at high voltage (HV) and low voltage (LV) is appropriate due to the complexity of the networks at this level. However, at the EHV level customers, both current and future, are more able to respond to the impact they have on the network and therefore more site-specific charges are appropriate. The FCP approach appears to average EHV charges within network groups, thereby diluting the locational signals that may well have materialised at individual nodes on the network within each group; and
- the approach to generation charging is based on the addition of blocks of generation (which are based on historical trends and uptake instead of future expectations)

rather than incremental cost being used to derive the marginal cost or benefit on the network.

The ENW methodology appears to be more closely aligned to the LRIC mechanism but is still at its embryonic stages, so it is difficult to provide a detailed assessment.

At lower voltages the options appear to be a simple decision between the current distribution reinforcement model (DRM) approach and the use of historical regulatory reporting pack (RRP) data mechanism. The latter approach appears to fail in that it uses retrospective data rather than being forward looking, which is a key principle of the methodology. Whilst RRP data may be appropriate for operating costs that vary little year-on-year, it does not seem suitable for the more volatile capital cost. Hence, we believe that the well established and understood DRM methodology would seem a better basis for deriving forward-looking charges. We do, however, recognise the fact that, because the DRM has been around since the 1980s, there has been some divergence in its application amongst those DNOs that currently use this mechanism and this will need to be resolved. That said, a number of DNOs have recently updated and modified the DRM to make it more robust and transparent and these developments would be a good starting point to re-establish an industry model for tariffs at lower voltages.

Appendix 2 sets out an assessment of how CE's current work (LRIC development at EHV and its subsequent integration into a DRM-type model for charges at lower voltages) measures up against the newly developed principles.

<u>The governance arrangements and the options set out in annex 3</u>

The introduction of revised governance arrangements can only add to the risk exposure of our business and increase uncertainty if there is a move from the current bilateral relationship between a DNO and Ofgem (supported by consultation) to a governance arrangement that involves multiple parties.

CE is in favour of fit-for-purpose, cost-effective governance that is designed to serve code parties. However, we must assume that change proposals will be put forward by those who have a vested interest in moving costs away from themselves, with the potential for parties to vote for changes that would ultimately be paid for by others. Any governance arrangements must be capable of dealing with the probability that votes will be cast in accordance with the interests of the particular organisation from which the panel member is drawn rather than with the greater good or economic purity of the model.

We believe there is a clear appetite among suppliers for certainty and predictability in UoS charges and we believe that independent distribution network operators (IDNOs) are looking for this also. While we recognise that other stakeholders have an interest in use of system (UoS) charges, including generators we should not ignore the aspirations of suppliers as our main customers for UoS.

Recent change proposals under the distribution connection and use of system agreement (DCUSA) and the balancing and settlement code (BSC) clearly demonstrate this appetite for certainty, including

- DCUSA 001A “Move to annual amendment of DUoS Charges”;
- DCUSA 030 “Provision of cost information; and
- BSC P216 “Audit of production of line loss factors”.

We would therefore caution against creating governance arrangements for methodologies that facilitate multiple changes either during, or across the boundary of, any given five-year price control period; significant price disturbance from one year to the next; or, worse still for suppliers, multiple changes to charges in a given year.

There is a risk that any changes to the selected charging methodology will be governed by an industry group and suppliers, generators, independent distribution network operators and any other interested industry stakeholder may change the grouped methodology and therefore affect the way and profile in which DNOs' income is recovered.

Since allowed income for DNOs is regulated by a five-yearly price control, the governance arrangements for changes to the structure of charges must take into account the fact that such changes could impact upon our regulated, or excluded services, income and upon our costs. DNOs must be protected from the risks that would arise from any misalignment between the price control regime and the regime that will determine changes to the charging structure. There are many ways that this could be dealt with including formal re-opener provisions within the special conditions of the licence. The principle must be that, within a price control period, no changes should be made to the charging structure that would have an adverse effect on the DNO unless compensation for that adverse effect is provided for under the price controls.

It is difficult to see how the existing licence arrangements will work once a common charging baseline and model have been established. Hence, one of the key challenges for any new governance arrangements will be to strike the right balance between desirable, but possibly conflicting, features, including:-

- Having code arrangements that serve the interests of the parties covered by and funding the costs of a particular code;
- Ease of access, use and transparency for the code parties, and others where appropriate; and
- Cost effectiveness, including a possible balance of flexibility, efficiency and robustness.

The review may reach the conclusion that governance arrangements that deliver the features of supporting licence objectives and accessibility to all interested parties; that are fully transparent, efficient and technically robust yet easy to use; and that will operate at a reasonable cost may not even be possible. Achieving the right compromises may be the key challenge in identifying the best way forward.

Any new arrangements will need to limit the number of modifications that can be considered in any particular year and will also need to be cognisant of other licence and distribution connection and use of system agreement (DCUSA) obligations. One potential solution may be to introduce an annual timetable managing possible change requests that allow a long enough period for developments to be undertaken.

The proposed processes set out in annex 4

As already stated, the timetable set out by Ofgem for achieving a common industry approach for setting of UoS charges is extremely challenging and aggressive (experience has shown that the data extraction process at EHV can take at least three months) given the scope of the work to be undertaken and the amount of alignment of processes that is required. Hence, we would urge Ofgem to provide an early decision on the form of a common charging methodology so that the working groups can be established at the earliest opportunity, thus maximising the amount of time for development and ensuring commonality across DNOs. It is only once the detailed project plans of the working groups have been developed and the exact scope of work identified that we shall truly be able to say whether the timeline is realistic and achievable.

One other area of concern with the proposed timetable is that it does not appear to factor in any time for system changes (i.e. updates to billing systems) that may result from a common industry solution and tariff structure, or the time required for the creation of new tariffs and the subsequent reallocation of customers to these tariffs.

It is essential that Ofgem should be very clear from the outset on the detailed modelling required and play an active part in ensuring the timetable is adhered to.

Whether there are any other matters we need to consider in light of our decision on a common charging methodology

There are a number of areas in the consultation where we have concerns or where we feel there would be benefit from further clarity. We would be happy to work with Ofgem to explore and define areas of uncertainty and risk to this project and, if necessary, assist in developing a licence condition that would more likely meet with the approval of licensees. The areas that would potentially benefit initially from further development and clarification are:

- How Ofgem would propose to treat DNO expenditure that could now be wasted due to a requirement to move to a common methodology;
- How Ofgem plans to treat the mechanism for distributed generation allowances, bearing in mind that there is currently no way in which a DNO can give negative cost signals to some generators without recovering that income from other generators (assuming full recovery of the price control allowances); and
- The introduction of a common tariff structure is likely to lead to a great deal of disturbance to end-user prices. It would also stifle opportunities for innovation and potentially require changes to systems that cannot be implemented overnight. This may not be Ofgem's intention.

Appendix 2 - Assessment of CE's developments against relevant principles

As well as developing methodologies to better meet the relevant objectives under SLC13, Ofgem and the DNOs have identified a set of high-level principles for the project. These principles are: cost reflectivity, simplicity (at point of use), transparency, predictability and facilitation of competition.

Following the April 2008 consultation document and recent discussions between DNOs and Ofgem, these principles have been developed further. Detailed below is a high-level assessment of how the work that CE is currently undertaking (LRIC development at EHV and its subsequent integration into a DRM-type model for charges at lower voltages) measures up against the newly developed relevant principles:

- **include all relevant information** - this principle relates to the manner in which the methodology is published. It is intended that the description of the methodology will include all of the material terms and distribution system cost data and cost allocation principles necessary to support the calculation of the use of system charges;
- **apply to both demand and generation** - the wording in this principle requires that the calculation of charges should be on a basis that is common and consistent. The mechanism that we are developing is designed to ensure symmetry of treatment between demand and generation so that locational signals are consistently interpreted by both classes of user. For EHV customers, charges are calculated for an incremental increase in demand at a given node, under the premise that the benefit of generation is equal and opposite to the cost of demand, and the same load flow modelling and contingency analysis are adopted for an incremental injection and withdrawal of power, resulting in equal and opposite charges. At lower voltages our current thinking is to utilise the existing DRM approach with the yardstick costs for generation being the negative of those for demand (this has the same impact as using negative coincidence factors). Such an approach would them maintain consistency in application of principles at all levels of the network and would generally create a credit for generators;
- **reflect all significant cost drivers** - in recognising the relevant cost drivers this principle requires that specific account be taken of time-of-day and seasonal influences, reactive power levels, fault levels and growth rates of, or within, parts of the distribution services area. The load flow modelling incorporated in the proposed LRIC methodology is conducted separately at times of highest and lowest system demand. This should reveal the cost of accommodating an increment of demand or generation on the system when the system is lightly loaded or under stress. The costs thus determined will be used to populate different cost yardsticks in the construction of the relevant tariffs, which can in turn be expressed as time-of-day or seasonal charges if this is appropriate (typically we would normally introduce a time-of-day signal, to encourage use of the system at times when it is less heavily loaded, where the metering and billing system functionality allows).

  The load flow modelling of the incremental increase in demand naturally reveals the cost of both the real and reactive power flows resulting at each part of the system on the EHV network. At HV and LV the DRM costs are based on a standard power factor of 0.95 to convert the £/kW and £/kVAr cost outputs into £/kVA prices. If in the longer term the extension of the LRIC approach to HV proved practicable, then it would be appropriate to contemplate revising the power factor assumption at the lower voltages.

  The UoB are currently considering how the cost function within the LRIC methodology could be extended to incorporate the costs of accommodating increasing fault levels. The impact of this would be that costs would differ between load and generation but, whilst the costs might not be symmetrical, the method for assessing the impact of generation or load on the network would remain so.

A key tenet of the LRIC approach also is to incorporate a background growth rate against which the impact of an increment of generation or demand is assessed. Where there is evidence that different parts of the network display different background rates of growth for demand or generation, these are incorporated into the model of the relevant circuits;

- **minimise the distortion of price signals where any adjustment or scaling of charges is necessary to ensure recovery of allowed revenue** - basing use of system charges on marginal capital costs is likely to require charges to be scaled to meet the target revenue permitted under the price control. Our proposal is to scale charges uniformly by means of a fixed adder so as not to distort the underlying cost signal derived from the composite of the LRIC and DRM methodologies. Consideration will be given to applying the adder as a commodity (p/kWh) charge. While the adder could be applied on either a £/kVA, £/kW or p/kWh basis to achieve the target revenue, it might be most appropriate to apply the adder as a commodity rate; i.e. as a fixed p/kWh charge as the addition effectively represents a tax, or rebate, on users;
- **recognise incremental costs and benefits on a forward-looking basis by virtue of users' use of the distribution system -** the LRIC methodology is forward- looking in that it assesses the incremental impact of demand or generation over the commercial life of the assets. Charges (prior to scaling) will reflect the costs or benefits of adding an increment of generation or demand. They will therefore indicate credits when either generation or demand has the effect of deferring costs that would otherwise be incurred. For the EHV network these economic signals will emerge on a nodal basis. At HV and LV they will initially be averaged across each licence area but it will be for future investigation as to whether further geographic separation of the charges would help facilitate the economic development of the network;
- **ensure that charges for EHV users vary by location and utilise power-flow modelling at the EHV level -** the LRIC treatment of the EHV network uses load flow analysis to assess the impact of the addition of an increment of generation or demand, and when conducting the contingency analysis assesses the security of the system under credible outage conditions. The approach thus complies with this relevant principle. If data intensity can be managed such that LRIC pricing can displace the DRM methodology at HV and LV, then power-flow modelling could be extended to lower voltages or alternatively some form of zoning of the power flow outputs at EHV could be used to provide stronger locational signals at lower voltages; and
- **be transparent and predictable to allow network users to estimate future charges** - so that suppliers and customers can make an assessment of the charges they are likely to be subjected to as the system (that is the network and the demand and generation supported by it) develops, consideration will be given to the feasibility of publishing both the LRIC and DRM models together with the associated data-sets on which the current charges are based. It may be necessary to simplify the data-sets to some extent in order to protect the commercial confidentiality of individual customers.