Our Ref PJD/18.0 Structure of Charges

SENT BY E-MAIL AND POST

Mr Mark Cox
Distribution Policy
Office of Gas and Electricity Markets
9 Millbank
London SW1P 3GE

Date 20 June 2005

Dear Mark

Structure of Electricity Distribution Charges: Consultation on the Longer Term Charging Framework

Thank you for the opportunity to comment on Ofgem's recent consultation document on longer term charging arrangements for electricity distribution networks. I can confirm that our response can be published on the Ofgem website.

EDF Energy has already implemented some major improvements to its charging methodology, most of which are mentioned as good practice in Ofgem's Longer Term Charging Framework document. These changes were introduced as part of the common charging methodology which was implemented in EDF Energy's three licensed areas on 1 April 2005.

This methodology has been developed to meet the needs of the relevant licence objectives in an efficient manner and in line with the key charging principles established by the Industry Steering Group ('ISG'). The new methodology provided a step change in our charges for network usage and any future development will only marginally improve these messages. The main improvements, which have already been delivered as part of this initial process, include:

- Charges for half hourly metered customers which provide capacity and time of day charge signals. These structures have a £/kVA capacity charge, providing a clear long-run signal to each user about the cost of their existing and increasing capacity requirements, and also five unit rates, providing an additional seasonal time of day ('STOD') cost signal.

- Simplified structures for non-half hourly metered customers based on the provision of a profiled tariff group consumption cost signal rather than retail tariff alignment, and maximising cost reflectivity without adversely impacting the Supercustomer settlement process.

EDF Energy
Atlantic House
Henson Road
Three Bridges
Crawley
West Sussex RH10 1QQ

EDF Energy plc
Registered in England and Wales
Registered No. 2366852
Registered Office:
40 Grosvenor Place Victoria
London SW1X 7EN
www.edfenergy.com

- A strengthening of the LRMC structure of our charges by moving away from the traditional Boley and Fowler Distribution Reinforcement Model, based on historic network costs, to one based on future network development using forward looking costs.

- Locational (site specific) prices for EHV demand and generation. Demand prices reflect shared usage through a £/kVA capacity charge, providing a clear long-run signal to each user on the cost of both their existing and increasing capacity requirements.

We believe that any long term charging model must strike the appropriate balance between complexity and the costs that this complexity imposes on DNOs and network users. The development of a model that provides locational signals is only useful if the network users value and can respond to such signals.

In our view, more complex modelling would only be practical at EHV levels and could only be truly applicable to users connected at that level. However, these users constitute approximately 100 out of 7.8 million customers on our networks and account for less than 10% of all consumption. These customers are already serviced through site specific locational charges. Additionally, most of this consumption is for rail traction supplies, and hence these customers are not necessarily able to manage consumption patterns. Those that can manage their usage pattern already do so, although this is generally in response to energy charges.

Across our distribution networks, approximately 60% of consumption is delivered to non-half hourly metered users, and therefore cost reflectivity is limited to the profile shape and the type of metering. This group of users will be completely inelastic to network pricing signals and our focus is to structure tariffs against the metering type and profile classes. Additional combinations could be constrained by the additional data volumes within the settlements process; therefore it is only practical to make changes which will clearly influence behaviour and have limited impact on settlement volumes.

The remaining 30% of consumption is attributable to customers with half hourly metering supplied at LV and HV. This group offers the most opportunity for development, which we believe can be implemented through tariff structure innovation. This innovation would involve modifications to billing systems and a move towards constrained time period and locational capacity charges.

Our detailed comments are provided in the attached paper. In addition to the summary of our progress to date and our views on model complexity, detailed above, we have outlined the other key points of our response below:

- Use of system charges are intrinsically linked to the connection boundary. In our opinion, there needs to be a period of stability at the connection boundary introduced in April 2005 if connectees and distribution network operators (‘DNOs’) are to fully understand and adapt to the resultant commercial implications. Further variation of the connection boundary should not occur until the price disturbance caused by the interim charging arrangements has had time to dissipate.

- We would be supportive of the development of a common methodology for line loss factors. In establishing a common methodology, we believe the underlying principles should be simplicity, equitability and transparency.

- If the scaling of modelled charges to allowed revenues is required, we believe it should be applied evenly to each tariff structure. The vast majority of distribution customers are fundamentally DUoS price inelastic, and any application of Ramsey type pricing is likely to have a detrimental impact on the most vulnerable sections of the community, such as the fuel poor. Certain methodologies, which are designed to replicate 'real' costs, do not require scaling. EDF Energy's current, site specific EHV approach is an example of such a methodology.

- In our view, any major disturbance in DUoS tariffs caused by changes in methodology should be smoothed over an appropriate time period.

- If Ofgem is minded to support consistent generator charging arrangements beyond 2010, then we would cite historic cost adjustment as the preferred method. However, we would need to develop a more detailed understanding of the rationale for these arrangements and their possible impact on users.

- We do not believe that negative demand charges are appropriate for demand within the overall context of energy efficiency, and would suggest that there is a much better case in principle for negative generation charges to drive the location of generation.

- We note Ofgem's position that it will be for DNOs to propose solutions to the charging issues, which will be commercial initiatives. However, if Ofgem prescribes a particular charging methodology for all DNOs, then we believe that an impact assessment is essential. This would allow all interested parties to comment on the costs and benefits of the methodology.

- We would support any joint work to investigate the feasibility of developing a common Use of System methodology. However, we do not believe that there should be a regulatory requirement for all DNOs to have a common methodology, as this may stifle innovation.

- The implementation of any new charging arrangements must be coordinated with the 2010 price control review (DPCR5). This is particularly important if, as an outcome of the review, there is a change to the connection charge boundary. It would also allow experience of both the DG market development and the operation of the GDUoS methodology.

I hope you find our comments helpful. If you would like to discuss any aspect of our response in further detail, please contact Jonathan Purdy, Income Reporting Manager, on 01293 509181.

Yours sincerely

Paul Delamare
Head of Regulation and Strategy
EDF Energy Networks Branch

Enc

EDF Energy's Detailed Comments on the Longer Term Charging Framework

1. Charging Principles

Ofgem and the Industry Steering Group (ISG) concluded on some high level charging principles, these being:

- Cost reflectivity
- Simplicity
- Transparency
- Predictability
- Facilitation of competition

We support these high level principles and believe that they currently underpin all that we strive to achieve. However, as was noted in the ISG, there are potential conflicts between these drivers. For example, a truly cost reflective model is likely to be extremely complex and hence compromise the simplicity objective. From our perspective, we also believe that flexibility is an important attribute. What we mean by this is that any model should be capable of reflecting actual differences in DNO networks and provide the ability for a DNO to innovate in tariff design.

Consideration needs to be given to those who have committed to long term arrangements and are basing future decisions over access to capacity against those who have short term gain. Long term connectees have in effect subscribed to a hedge or an insurance on access rights, and this has helped establish secure and robust network provision. Network cost and security should not be impaired by short term 'economic' signals. Facilitation of a new connectee should not destabilise an existing user's viability wholly through a third party's action.

We agree that past costs should not influence future charges but we do not agree that the key driver for economic efficiency is only to reflect future costs. Economic efficiency must also be driven by the current costs of maintaining an existing network. Customers' future decisions must be influenced by the impact of future costs against their current costs.

2. Current Charging Model

The 500MW model is the generic name for the Distribution Reinforcement Model ('DRM') approach used to apportion costs to each voltage level. However, in practice the models are likely to differ from that envisaged by Boley and Fowler and developed during the 1970s and 1980s. Our model gives a representation of the costs of providing our networks over the current horizon of expenditure. This is a development on the original concept of a simulated network.

The simulated model provided for a 'brown field' development of a new network as if it were built today. The simulation was designed to mirror the DNO's area. The deficiency of this approach is that it does not account for where a DNO is actually spending money and, consequently, any spare assets. Additionally, a 'brown field' development built looking forward would not replicate a DNO's existing network, as environmental considerations would involve the undergrounding of all conductors. This forward looking approach would not recognise the intrinsic value of existing overhead assets.

Our development of the model takes account of what assets are being provided looking forward in relation to how they blend with the existing network design. Locational signals are seen through the provision of separate components of the model to cover the rural and urban nature of the system. Although the model would not currently accommodate generation, a future additional model could be created which would then distinguish between demand and generation costs.

Distribution systems have changed since the introduction of the DRM. Technology has seen the introduction of additional user requirements and possibly the only failing is the transparency of how these users' costs or benefits are apportioned. We believe our current models are best placed to be developed in order to provide a 'roughly right' cost signal, which can be demonstrated, through improved communication and understanding with users, as being cost reflective, fair and equitable.

3. Type of Model

All of the academics agreed that the efficient charge is one based on the long-run cost on a forward looking basis. From a purely economic perspective, this is correct. However, as noted later in the document, such an approach will not recover the total allowed revenue that is required by a DNO; therefore, the practicality of developing a pure investment cost model is debatable, especially as locational signals will be better affected by application of current costs. With respect to the application of marginal costing to the distribution network, we agree with Newberry's conclusion that it is more important for large loads and generation, ie those who can respond to locational signals. This would tend to suggest that the focus on developing a new charging model should be at the EHV level. Such an approach would reduce complexity and hence implementation costs.

We believe that the models should be forward looking, taking account of tomorrow's immediate costs as well as those on the wider horizon. However, it is too simplistic to dismiss the inclusion of all short-run costs; indeed, for the vast majority of users, short-run costs would most likely be the influencing factor on economic behaviour if locational prices were implemented.

We agree that cost drivers are fundamental to the determination of suitable charging models and we will support the work in this area. In particular, we believe that certain tariffs can be structured to better reflect Time of Day components. Before a generation security standard can be developed, it is necessary to understand the costs and benefits that are likely to flow from such a standard. This is essential, as the funding of such a standard will impose additional costs on the entire customer base and may require significant changes to DNO networks.

Theoretically, models can be conceptually envisaged, but the practical application of electrical and then financial modelling of demand and generation with locational variation will prove costly and resource consuming in its implementation.

4. Specific Models Advocated by the Academics and Exemplar Models

It has not been demonstrated that there is a suitable model that provides an end to end solution; therefore considerably more work is required to solve the constraints and limitations that would be experienced. Until this has been achieved, we do not have confidence that users will be in any way better off under a new approach. A new model must provide demonstrable improvements on the one currently in use in order to gain our support in moving to it.

The academics have raised some interesting concepts, which we will consider as part of this review. We are, however, mindful that there are shortfalls in the exemplar models and that work is in progress to attempt to address users' concerns.

5. Detailed Charging Issues

Connection Charging Boundary

Use of system charges are intrinsically linked to the connection boundary and any review of one impacts the other.

Notwithstanding this, there is a need for a period of stability at the connection boundary introduced in April 2005, in order to allow connectees and DNOs to understand and adapt to the commercial implications of the new connection boundary. To undertake further changes to the connection boundary in the short term is likely to cause confusion and raise anxieties for our customers. Further variation of the connection boundary should not occur until the price disturbance caused by the interim charging arrangements has had time to dissipate. Most developments requiring connection are subject to significant planning and lead time. Whilst a DNO can adapt rapidly to changes in this area, repeated changes to the connection boundary would, in our opinion, impose an unreasonable regulatory risk on developers, who often set budgets for projects one to two years in advance.

Also intrinsically bound up with the connection/use of system boundary is the revenue allowed under the price control. This makes the most appropriate time for any change to the boundary to be concurrent with a price control, thereby avoiding the need for mid-term adjustments to the control and minimising the regulatory risk placed on DNOs.

Review of Tariff Structures

There are significant constraints on the 'messages' DUoS tariffs can provide to the non-half hourly markets because of the nature of the metering. The decision on choice of meter is made by the supplier and is driven by their tariff structures rather than those of the DNO. The profiling of non-half hourly data does make it theoretically possible to implement seasonal time of day ('STOD') type tariffs into this market. However, this is likely to be of very limited effect. The settlement profiles are common across all customers of a particular class, and while profiles are flexed to represent an individual customer's actual consumption, the half hourly proportions are essentially fixed. For example, a domestic customer who deliberately minimised their usage during the 'winter tea time' system peak would still be attributed an average usage during that period by settlements (as would the customer's supplier).

It is worth debating the effect of non-half hourly transmission use of system (TNUoS) charges on user behaviours. Since 1998, non-half hourly TNUoS has been levied on the basis of the profiled settlement usage between 1600 hours and 1900 hours daily. To our knowledge, there is no evidence that this TNUoS tariffs structure has had any effect on user behaviour.

We have already consolidated and simplified the number of tariff structures used. In the half hourly market, STOD type tariffs - with a strong capacity component - are a feature of our current methodology. We anticipate that half hourly tariff structures will develop over time, and there is potentially scope to develop an industry 'best practice' approach to help standardise billing systems and drive appropriate signals. One area in which development may be appropriate is to consider STOD capacity tariffs in preference to overall annual usage. An example of this approach is half hourly TNUoS, where the triad methodology can provide a very strong driver to behaviour.

There also needs to be some understanding as to the dual effects of methodology and tariff structures. The most complete, most 'accurate', most resource-intensive, economically driven modelling, when converted to a p/kWh non-half hourly tariff structure, is highly unlikely to have any impact on customers' behaviour and would be an inefficient cost to a DNO.

Line Loss Factors

Line Loss Factors ('LLFs') are a mechanism to allocate losses across customers (and their suppliers) and are not a measure of absolute losses. The overall losses on distribution networks are calculated annually and reported to Ofgem under the Distribution Licence. This makes the calculation of LLFs an area where DNOs are essentially commercially neutral.

EDF Energy believes that there is a much stronger case for commonality of approach across DNOs in calculating and setting loss factors. The neutrality of DNOs in the LLF setting process suggests that a collective approach to the creation of a common LLF methodology across all DNOs may be appropriate, and any such work would be supported by EDF Energy.

We believe that in establishing a common methodology for LLFs as an allocative mechanism, the underlying principles should be simplicity, equitability and transparency. A common LLF methodology would also negate the requirement for individual inclusion in charging methodologies.

Scaling of Charges to Revenues

The scaling of modelled charges to revenues should be applied evenly to each tariff structure. The vast majority of distribution customers are fundamentally DUoS price inelastic and any approach to Ramsey type pricing is likely to have a detrimental impact on the most vulnerable sections of the community, such as the fuel poor. Certain methodologies, which are designed to replicate 'real' costs, do not require scaling. EDF Energy's current site specific EHV approach is an example of such a methodology.

Transition Arrangements

As we stated in our first draft Use of System Methodology Statement last year (and removed as required by Ofgem), we believe that any major disturbance in DUoS tariffs, as a consequence of methodology change, should be smoothed over an appropriate time period. This is only likely to be an issue moving forward if significant changes to methodologies (including, but not limited to, locational charges or Ramsey pricing techniques) are introduced. We believe that the final disturbance level arrived at by Ofgem (after consultation with major users) for EHV charges (15% per annum) is appropriate for most customers.

Generation Charging Issues

a) Arrangements for 2010

EDF Energy is generally opposed to grandfathered[1] rights in charging arrangements. In our experience, most generators connected prior to April 2005 have not paid significant deep connection charges. Secondly, demand customers have seen movement in the connection boundary several times since 1990 and no account has been taken by the regulatory environment of these changes.

If Ofgem is minded to support consistent generator charging arrangements beyond 2010, then we would cite historic cost adjustment as the preferred method. However, we would need to develop a more detailed understanding of the rationale for these arrangements and their possible impact on users.

1 A clause creating an exemption (as from a law or regulation) based on circumstances previously existing.

b) Distributed Generation and Deferred Expenditure

The issue of deferred expenditure as a result of distributed generation (or demand) on distribution networks is one of the most complex areas of work. It is fairly simple to state as a set of theoretical economic principles but we believe that it will require a great deal of work to devise an effective means of measuring and modelling. There will also be obligations on those providing the benefit to ensure that there is continual support for the network. Any demand expenditure deferred as a result of generation will need to be balanced in the model against costs resulting from generation.

We do not believe that negative demand charges are appropriate for demand within the overall context of energy efficiency. While it may truly reflect the economic utilisation of a distribution network at a certain location and time, we agree that it would be a perverse incentive in the wider energy and environmental context and should be avoided. There is a much better case in principle for negative generation charges to drive the location of generation, as on the transmission network.

c) Ancillary Services and Active System Management

The ancillary service market and active system management in distribution have not developed. They can only be expected to grow once there is significant generation connected to distribution networks. We consider that any development over the next few years will (and should be) bilateral in nature rather than on a 'market' basis.

d) Reactive Power Charges

The principles of incentivising customer behaviour on power factor and, therefore, reactive power are common for demand and generation. Poor power factors cause additional losses and can drive capital expenditure. If a customer's actions place a burden on the network through a poor power factor, then that customer should bear the cost. We consider that the current EDF Energy methodology addresses the use of reactive power effectively, with the resultant charges providing a good incentive for customers to make decisions about managing their power factor.

There are wider issues relating to the application of reactive power incentives in that the metering requirements are driven by the supplier. The reality is that even in the half hourly metered market, DNOs do not receive reactive power data for more then 50% of customers. As cost reflection and fairness is impaired, suppliers should be encouraged to provide this data through the application of 'estimated' charges.

Generators exporting reactive power can provide a compensatory effects benefit if correctly located. We believe more work is needed on the development of appropriate reactive power incentive arrangements for generators.

6. Development Process Issues

Consistency between DNO Areas/Models

We would support any joint work to investigate the feasibility of developing a common Use of System methodology. However, we do not believe that there should be a regulatory requirement for all DNOs to have a common methodology, as this may stifle innovation.

Joint working and development of a common approach is likely to extend the timescales for delivery. Similarly, the outcome from the process may involve industry change to a magnitude which would necessitate a formal impact assessment.

Provision of Charging Model to Users

EDF Energy believes that improved communication between DNOs and users is the best route to building and improving understanding. Users need to be in a position to forecast the forward curve of prices. While we are not opposed to the publication of use of system charging models in principle, we do consider that understanding the model will not entirely accomplish this. However, the use of models alone will not enable the forecast of prices, as along with other data, it would still need to be scaled against the movement of the allowed revenue. Additionally, there are issues as to the cost and documentation of provision and the level of support that DNOs would be expected to provide.

It would be appreciated if Ofgem could seek and publish feedback on the effectiveness of the provision of the transmission models by NGC and determine the demand that might be placed upon a DNO in relation to its models (given the number of end customers) before proceeding further.

Inclusion of IDNOs in Methodology Requirements

EDF Energy considers it logical that all licensed network operators should be required to have an approved methodology. The Condition 4 obligations should therefore apply to IDNOs.

7. Regulatory Impact Assessment

Our thoughts on the majority of questions raised in this section are answered elsewhere in the document and will not be repeated here.

We are disappointed that Ofgem does not believe it appropriate to conduct a full regulatory impact assessment ('RIA') for the structure of charges project. The opening words of the consultation document refer to a 'structure of charges project'; we are therefore somewhat confused to read in paragraph 5.2 that Ofgem is not initiating a project or implementing a policy, and does not intend to conduct a full RIA on this area. While the impact of each proposed change resulting from a DNO proposal for methodology change will be picked up by Ofgem's proposed approach, it is the overall programme of activity that Ofgem is proposing which requires an impact assessment.

A full RIA on the structure of charges project is therefore required. We do not believe that a full cost benefit analysis has been conducted for the structure of charges project which rigorously identifies the benefits for customers.

Implementation

Project Leadership and Role of the ISG

As identified by Ofgem, this area will need to be led by the DNOs. However, it is important that there is wide consultation as to the effects on users and to understand what users actually require. This part of the process is undoubtedly best coordinated by Ofgem and is a role we envisage the ISG or any successor group fulfilling.

We also consider that account must be taken of Competition Act issues with regard to common working by DNOs/IDNOs and that the emergence of a single DNO working group may not be viewed as an optimal solution. If there are a number of such groups, or if some DNOs decide to act independently, it will be necessary for an all industry forum to exist as a sounding board and for discussion with users to take place.

Timing of Implementation

EDF Energy is one of three DNOs with a conditional approval relating to its charging methodology, and we are currently devoting our resources to complying with these conditions. As a regulatory requirement, this work has a priority for us over the development of the longer term framework.

It is likely that a full and final solution, incorporating an integrated approach to demand and generation charging, can only be introduced concurrently with a price control. This indicates 2010 as the appropriate time for full implementation. Clearly, the earlier users have an understanding of the final arrangements, the better. However, we consider that there should be an emphasis on 'getting it right' rather then 'doing it quickly'. Our desire to seek a commonality of approach among DNOs will require time to develop and may involve further work (perhaps under the IFI initiative) with academic institutions.

As with the revised connection boundary, there needs to be a period of stability to allow connectees and DNOs to understand and adapt to the commercial implications of generator DUoS, the interim arrangements for which are less than three months old. While this should not stop development work, EDF Energy believes that undertaking further changes in the very short term is likely to cause confusion and raise anxieties for its customers. Generator DUoS should be allowed to bed in over the next two to three years, concurrent with development work, so that proposals can be tested against some, albeit limited, market history.

Interaction with Other Events and Projects

As outlined above, the implementation of any new charging arrangements will have to be coordinated with the 2010 price control review (DPCR5). It is too soon to envisage how the Structure of Charges process will impact on the possible development of new governance arrangements, although clearly there will be an interaction between the two.

EDF Energy
20 June 2005