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Dear Martin

Consultation on use of system charges to new electricity distribution licensees: WPD and SP proposals

Your letter of 8 May 2007 raises important issues that are relevant to all electricity distributors. It is not easy to answer your main questions which seek views on whether the proposals by these DNOs better achieve the 'relevant objectives' in condition 4 of their Distribution licences. This requires a detailed understanding of their current models and of their particular cost and customer bases. Such information is not available from either your consultation or the modification applications that we have seen. It also requires a view to be taken on the relative importance of those objectives. You cite only two of the four relevant objectives in paragraph 3 of Condition 4, yet all should be taken into account. It seems particularly appropriate to consider the wider interests of all consumers and therefore to reflect on the impact on all DUoS tariffs of the proposals that are being made.

Rather than directly answer the questions you have posed, I will structure our response around the discussion of key issues set out in Annex 2 and Annex 3 to your letter.

1. Specific yardsticks for IDNOs

The process of designing use of system tariffs involves a number of steps. The first key element is the attribution of network costs by system voltage level. For this purpose, we begin by establishing the cost of providing an incremental kVA of capacity. The conversion of this cost into particular tariff elements depends on the extent of data available on which to bill use of system charges. The less data that can be expected, the more it is necessary to rely on assessments of characteristics for customer classes. This replaces the availability of actual data that could be obtained from metering.

Since most costs can be attributed to capacity requirements and they in turn are best interpreted by reference to system peak, the use of half hourly metering offers the best opportunity to bill on the basis of genuine contribution to costs. Where such data is not available customer characteristics are assessed from less reliable usage indicators. The second best option is to use a maximum demand measurement, since this only requires an assessment of how, on average, a customer's maximum demand can be related to usage at the time of system peak. Where only kWh metering is available, another level of estimation

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is required to relate kWh usage back to maximum demand, through the use of assumed load factors.

Consequently it is not possible to conclude immediately whether separate yardsticks are needed for a particular sub-class of customers. This is itself dependent on the form of metering used and the detail available on individual load shapes.

In our experience the use of maximum demand metering, allowing use of system charges to be a combination of kVA/kW and kWh prices, removes much of the argument for separate yardsticks. We have previously demonstrated in work shared with Ofgem that typical domestic load shapes face no higher usage charges on our MD tariffs than on the tariffs designed to apply to suppliers in respect of their domestic connection points.

It is therefore likely that more tariff yardsticks are required if metering does not provide the necessary information on usage patterns. Given the relatively low costs of providing maximum demand metering, the case for additional yardsticks is far from conclusive.

2. Avoided costs

If DUoS prices are broadly cost reflective it will follow that differences between tariffs will reflect the differences in underlying costs. However there will always be an issue where the basis of charging is tariffs, since each individual exit point will have different costs. The challenge in designing a suite of tariffs is to ensure that significant cost differences are recognised in the range of tariffs available, without presenting such complexity as to make application impractical. DNOs have typically achieved this compromise by offering different tariffs for each voltage of connection (usually also differentiating between network and substation connections) and for lv customers also offering domestic and non-domestic variations for exit points that have only simple kWh metering. Within any tariff class there will be variations in cost around the average used for tariff design. These may often include positive and negative variances under specific cost headings. It is a matter of judgement as to when these should be recognised in greater complexity.

Our assessment of the variability of margins available to IDNOs on the basis of our experience to date does not suggest that our current structure of tariffs is inappropriate. However, in common with ScottishPower we have found evidence that the impact of availability charges based on anticipated final capacity requirements can have a damaging effect on margins in the start up period. We have encouraged IDNOs to consider more carefully the way they specify their requirements to us in order to mitigate this effect.

For your information, I attach an analysis of our network use of system tariffs in the same form as shown in your Annex 4.

3. Tariff design and capacity charging

As I have explained above, the key driver of network costs is the capacity requested by each connecting party. We therefore believe that capacity charges are an essential feature of good tariff design for all except the smallest of connections. It is important, however, that data collection and processing costs do not become excessive and we now recognise that it is not desirable to insist on half hourly metering for all IDNO sites. We would also expect to be able to agree billing arrangements that could rely on the use of estimates between meter readings that may be taken at less frequent intervals by an IDNO's staff or agents.

4. Reactive power

Whilst measures of demand are taken in kW we believe it is appropriate to also indicate to all connected parties, the additional costs that arise from poor power factor. This means that those customers who draw additional power through our network are charged accordingly. The argument that most IDNO networks operate at a power factor close to unity seems to miss the point. If this is the case they will not pay for reactive power. Where this is not the case, and power factors are markedly different from unity, it would not be cost reflective to ignore the fact.

5. Metering

We are aware of the significant volume of debate around metering of IDNO networks. We believe it is important to maintain the principle that all (bar the very smallest) connections should be measured. This will secure consistency with other network users connecting at a similar pointing the network and properly establish the boundary of risk between two distinct commercial organisations. Without metering at the boundary, any failings in the performance of the IDNO (whether in registering and ensuring measurement of all connected load or generation, providing and maintaining assets with appropriate loss characteristics within and efficient design) would fall on the DNO. This would work to the long term detriment of all customers, since costs falling inappropriately on the DNO would in the fullness of time be reflected in price controls, and these would, in turn, affect the charges the IDNO made to its own customers. Regulatory incentives would have been distorted and all customers would be worse off.

Our research has indicated that the installed cost of boundary metering should be less than £100, which could normally be spread over a life of at least ten years. With suitable agreement on estimated billing, data collection costs could be close to zero, with readings scheduled to fit with other visits to sites by the IDNO or its agents.

6. Capacity increases

As mentioned above we accept that this is an issue which needs to be addressed. The problem is not just one for IDNOs but may also apply for other customers whose load is likely to build up gradually (as with a new factory or commercial complex where construction or fitting out is in phases). However, as ScottishPower point out, this is about tariff application, not tariff design.

7. Asset adoption payments

We have been working on a modification to our Connection Charging statement, required under Condition 4B of our licence. Given the nature of our charging models it seems right for us to offer a payment to connection providers who are willing to pass assets to us for adoption. This is consistent with our understanding of the arrangements that IDNOs will offer. In our view adoption payments should be published by all distribution licensees in their condition 4B statements. This would help all connection providers and customers to better evaluate the alternatives available to them.

I hope that you find these comments helpful. I would be pleased to discuss them with you further if that would be of assistance.

Yours sincerely

Mike Boxall
Electricity Regulation Director

Illustrative examples of IDNOs' Gross Margin for Connections in UU

This table shows figures for comparison with those of Annex 4 of Ofgem's 'Consultation on use of system charges to new electricity distribution licencees: WPD and SP proposals'.

	All the way income IDNO collects	IDNO income per plot	Site boundary charge by DNO to IDNO	Site IDNO gross margin	IDNO margin per plot	% of total of all the way charge
UU Apr '07 LV MD tariff	3021	67	2270	751	17	25
UU Apr '07 HV MD tariff	10070	67	6463	3608	24	36
UU Sep '07 LV MD tariff	3245	72	2469	777	17	24
UU Sep '07 HV MD tariff	10818	72	6970	3848	26	36

Assumptions:

	LV	HV	
Number of houses	45	150	
Average household consumption	3900	3900	kWh
Average household capacity	2	2	kVA
Capacity diversity factor	1	1	
Diversified site capacity	90	300	kVA
Day unit %	75	75	
Night unit %	25	25	