## Scottish Power's proposed modification of their use of system charging methodology

**Response to Ofgem Consultation 86/08 by**
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### *Introduction*

We welcome the opportunity to respond to Ofgem consultation on the proposed use of system charging methodology proposed by Scottish Power (SP). Whilst we have been proponents of the LRIC approach to distribution use of system charging that has to date been implemented only by WPD for its EHV connected customers, we believe that consideration of the SP proposal will help the industry develop its thinking on finding a robust and enduring charging methodology that will support wider policy objectives concerning the environment and a transition to a lower carbon economy.

The proposed SP charging methodology raises a number of complex issues. It has proved difficult to fully understand some of these from the modification proposal published by SP Energy Networks on 9th May 2008. The paper by Frontier Economics, which has clearly been written following extensive discussions with the G3, is helpful in increasing our understanding. However, it is possible that some of our comments may be based on a misconception of what is intended.

### *Generally*

In addition to posing a number of specific questions Ofgem's consultation also seeks views on whether the approach represents an appropriate balance of the charging principles. These state that a use of system charging methodology should be cost reflective, transparent in its construction, produce charges that are predictable and simple at the point of use, and facilitate competition in supply and generation. Whilst a balance will need to be struck between these principles, since inevitably there will be tensions between them, our view is that the principle of cost reflectivity is paramount.

As the paper by Frontier Economics discusses cost reflection can be construed in two ways; either as being reflective of total costs, or as reflecting incremental or marginal costs. The former construction has been used in the past to justify an equitable allocation of cost amongst users, but economic theory indicates that there is a more efficient use of resources if prices reflect incremental costs. Paragraph 6.19 of the Scottish Power modification proposal indicates that the fundamental concept that supports the Forward Cost pricing approach (FCP) is that the costs of reinforcement are recovered between an initial time T prior to reinforcement and the time of reinforcement. This implies that the cost reflection that is being sought is in respect of total costs rather than the marginal costs of adding new demand. For HV load this basis is even more explicit.

We believe this to be a fatal flaw in the approach that has been developed. The purpose of introducing locational signals into distribution charges is to encourage the efficient use of the system and thus facilitate competition in the supply of load, and particularly in the connection of distributed generation, which is likely to demonstrate the strongest price elasticity. For locational signals to be fully effective they should be derived on a basis that reflects the incremental or marginal costs of serving generation and demand. An average or total cost approach is unlikely to properly reveal the cost of adding demand or generation at any specific location.

A key feature of a network charging methodology should be to create symmetry between generation and demand, so that the system can appropriately recognise the contribution from generation and demand reduction. Unless this approach is taken there will be distortion in competition between demand management (supply) and generation.

Developing an appropriate network charging methodology must also meet a number of competing objectives, some of which may conflict. Most obviously the requirement to reflect the costs of meeting incremental demand or generation may not align with the revenue recovery permitted under the price control. The conventional approach of allocating operational and maintenance costs allowed under the price control directly to customer groups reduces the quantum of the charge that will need to be scaled to deliver the target revenue. However it could also exacerbate the scaling that is required of the capital related component of the charge since this now represents a smaller base.

***Specific Questions (from the body of the report, not Schedule 7)***

*The use of Network group aggregation and different increments*

*The extent to which SP's approach to demand charging is an acceptable trade off between cost reflectivity and stability.*

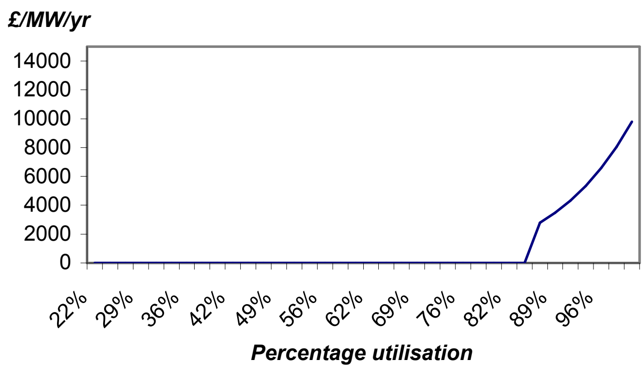
*The extent to which the use of network aggregation and separate increments are equitable and capable of producing economic signals which can lead to more efficient use of the system.*

*The appropriateness of the charging function*

As we have noted above our view is that the capital related component of the charge should reflect the marginal costs of adding an increment of generation or demand. To the extent that the SP methodology is seen as being "cost reflective" it would appear to introduce an unnecessary instability. We understand from the description of the methodology that future reinforcement costs are only recognised when the utilisation of a circuit exceeds 87% of its maximum power flow. This will create a step change in the charges when this threshold is crossed, thus reducing stability of charges. It also masks any forward message of how reinforcement might be delayed if the circuit has yet to reach its capacity limit.

The step change in the charging function that emerges with changing utilisation is vividly illustrated in the diagram below:

Figure: FCP demand charges with changing circuit utilisation




The selection of a charging group as a preliminary step prior to conducting the load flow analysis that establishes the horizon for the reinforcement of circuits risks masking the incremental costs that might otherwise emerge at individual nodes on the network. Furthermore we understand that the maximum allowed power flow for each circuit is derived from a whole-system contingency analysis, which implies that a circuit within the network group might carry additional contingent power flow from circuits outside the group. This would seem to negate much of the locational signal that would otherwise be apparent. In devising reinforcement schemes planning engineers are likely to transfer load between nodes, which might be an argument for averaging nodal prices across a group of nodes in close proximity. However, it would be better to make this judgement after the incremental cost at each node has been established rather than pre-empt the nodal calculation and subsequent averaging process.

The SP proposal uses different pricing functions for generation and demand at both EHV and HV/LV. Thus the FCP model is really a collection of four models rather than a single model. The advent of active management of distribution networks and the impact of smart metering at the lower voltages could bring anomalies between the various pricing functions into even sharper relief. We would expect a distributor's charging methodology to use the same pricing function for demand and generation at each voltage level, although the costs addressed by the pricing function could be different. SP's recognition of fault level costs, which will be more significant for generation than demand, is a useful step forward in this latter respect.

*The use of a test size generator and standard probability in EHV/HV generation charges*

*We ask for views on the extent to which the use of the test size generator represents an appropriate trade off between a forward looking, cost reflective methodology and a methodology which produces predictable, stable prices.*

*We ask respondents to consider the fact that EHV demand growth is also likely to be lumpy. Respondents may also wish to consider the anticipated growth of small scale distributed generation which is likely to flatten and "lumpy" connection of generation.*

As the Frontier paper notes the approach taken to deriving GDUoS charges at the EHV level is reflective of the total cost of adding a quantum of new generation rather than an incremental cost that might be used to reveal the marginal cost or benefit to the network. We would have concerns about the approach on this basis alone but whilst the approach may produce charges that are “predictable” it may have little relevance for the reality of what might happen.

Our view is that charges from a pricing model should provide an economic message that will influence the future location of generation and demand. The probability of generation connecting should be shaped by the locational signals in the network charges instead of by the underlying assumptions. In the SP approach new generation capacity is taken to be 30% of the current peak demand within a network group, and new generation is apportioned to different voltage levels on the basis of the proportion of the existing generators connected to the network. This would appear to be a backward-looking rather than forward-looking approach.

In using historic data to derive the size of the test generator, and its probability of connection, the SP approach draws on data reflecting in situ technologies rather than those that might be employed in any future schemes. This could be particularly misleading where there are older industrial processes, and it would not reflect the anticipated growth in renewable generation or CHP. Even if an average cost approach was appropriate it might not produce stable prices in the event that a large generator were to close (perhaps as the result of the impact of emissions legislation) and produce a step change in the nature of the generation connected to a charging group.

A charging methodology based on a change in total costs will be sensitive to the assumption made about the quantum of generation or demand that is connected. An electricity system might be said to live on the diversity between different loads and generators. If a marginal cost approach is adopted then the locational cost signal will be derived as a tangent to a continuous cost curve. Such an approach does not deal with the lumpiness of the addition of load or generation that might connect at EHV, but any use of system methodology will need to be seen in conjunction with a connection charging methodology which would help address the “lumpiness” issue.

*Varying the size of the test size generator*

*We welcome views on the extent to which it is appropriate for generator charges to go up when smaller generation connects to the network, and down when larger scale generation connects to the network*

*We also welcome views on whether the substantial differences between test-size generators at different voltage levels may influence connection decisions i.e. a generator may connect at 33kV rather than 132kV.*

The result from Ofgem’s analysis does appear somewhat perverse and would seem to result mainly from the simplifying assumptions used in the pricing function, such as assuming a linear relationship between the probability of generation connecting and the probability of network reinforcement costs being incurred.

*Revenue reconciliation*

*We welcome views on the extent to which SP’s proposed scaling approach is appropriate both in terms of the ‘COG’ model and voltage level scaling.*

*We also welcome views on whether the different scaling approaches to demand and generation are appropriate.*

A use of system methodology that seeks to provide locational signals for demand and generation should endeavour to minimise any distortion to those signals as the result of scaling of the charges for the purpose of meeting the permitted price control revenue. Frontier Economics has expressed concern at the substantial degree of scaling that is used at the EHV level. However, the magnitude of this factor may be a consequence of the second concern they express regarding the application of a different scaling factor at each voltage level depending upon the MEA value of the assets at each voltage level.

The scaling of charges effectively represents a tax on users to recompense shareholders for past investments that may now be partially stranded or technologically obsolete. Whilst it may appear inequitable to load costs that have resulted from, for example, an over-planted EHV network from which energy intensive industries have now departed, it might be held to be equally inequitable to charge the residual customers connected at EHV for these costs. Our view would be that any scaling that is necessary should not discriminate between different voltage levels so as not to distort the underlying price signals.

The SP methodology also applies different scaling factors for generation and demand. This may be simply a consequence of separate price control targets. Although Ofgem has still to opine on the matter we think it unlikely that this practice will continue under DCPR5. Since generation is the most price elastic of all users it may be considered appropriate to apply any scaling that is needed solely to demand. If generation has to bear the scaling "tax" then it will simply result in higher costs that will eventually be borne by demand and create an inefficient route for this charge to the end user.

*Use of historic RRP data in HV/LV charging*

*We welcome views on the extent to which the use of historical RRP data represents an appropriate trade off between cost reflectivity and simplicity, and whether this approach is transparent given that RRP data is not published.*

*We also invite views on whether a backward looking average technique is appropriate given the presence of developed forward looking models, particularly for the calculation of HV and LV reinforcement costs.*

The use of historical RRP data as the basis for determining the capital component of HV/LV charges would seem to be fraught with difficulties. Whilst undoubtedly simple in construction the approach cannot be considered transparent since the RRP data is not published. Once again the approach is founded on the idea of the reflection of total costs rather than incremental costs which we believe would better encourage economic efficiency.

Notwithstanding this, RRP data may provide the most relevant source of operating costs for incorporation in any charging model. If this information is not in the public domain then Ofgem may want to give consideration to how it could be published in order to aid transparency.

The approach would also appear to fail on its use of retrospective data rather than being forward looking, which should be a key principle of the methodology. By being a "business as usual model" it would appear to conflict with the significant anticipated growth in distributed and micro-generation. The established DRM would seem a better basis for deriving forward looking charges than that proposed by SP, albeit it does not incorporate the sophistication of a methodology that encompasses power flow modelling of the network.

*Coincidence with system peak*

*We welcome views on the extent to which SP's proposal incorporates customer coincidence to peak demand and incentivises higher utilisation of the network based on time of day and seasonal influences.*

*We also welcome views on the extent to which SP are correct in using four time periods for HV/LV customers while only one time period for EHV customers.*

The description of the allocation of costs to the various tariff yardsticks indicates that SP proposes to allocate the EHV FCP derived capital charges to each of the four chosen time periods for HV and LV connected load depending upon the demand profile of customers connected at these voltages. If the cost driver for reinforcement of the system is the demand at times when the system is under stress then it would seem more appropriate for these costs to be focussed into these times. It is imagined that this would usually be times of winter peak demand although parts of the system may be under stress at other times. For example city centres may demonstrate local peak demand on summer business days when air conditioning load predominates, and remoter rural networks may peak at winter nights if there are substantial quantities of storage heating load connected.

The sophistication with which cost signals can be passed to the end customer will generally depend upon the sophistication of the metering that is employed. For NHH customers there is little scope other than to introduce a day/night differential in the charges. However, for customers that have half-hourly metering a more precise linkage of costs to time should be possible. It is a little curious therefore that the time period for EHV customers are not more disaggregated than for HV/LV customers.

*Different approaches between demand and generation*

*We welcome views on table 1 and the extent to which there are substantive differences between demand and generation which warrant an asymmetric approach.*

*Do respondents consider that SP's approach is appropriate?*

As noted earlier for a charging methodology to encourage efficient use of the network and ensure future investment that is economic, it should be capable of revealing the relative merits of demand management and distributed generation. This would argue for incremental charges for demand and generation to be derived from the same pricing model. Inevitably the cost consequence of adding load and generation to the distribution network may be different because their impact on the system could be different, but the pricing approach should be the same so that an economic comparison can be made. The FCP approach uses four different models which have quite different attributes, as is illustrated by table 1.

In summary we do not think the SP approach is appropriate for the following reasons:

- It is based on a total cost approach instead of an incremental costs approach which would encourage economic efficiency
- It employs four pricing models which have a lack of symmetry between generation and demand
- The HV/LV demand model appears to be backward rather than forward looking.

*Use of a ten year recovery period*

*We welcome views as to whether it is appropriate to only consider demand reinforcements which will occur within a ten year period. Does this represent a practical trade off between a forward looking model and a simplistic approach?*

*We welcome views on whether it is appropriate to only assess the benefit generation can have in deferring demand reinforcements due within ten years. Does this adequately reflect the benefits which generation can provide to the distribution network?*

*We welcome views on the potential for the use of a ten year period to lead to tariff jumps as lumpy demand connection brings forward reinforcement by a number of years.*

The ten year cut off and the 87% threshold in the utilisation before reinforcement is recognised both introduce discontinuities in the pricing functions that have the potential to pervert the economic signals in the use of system charges and confuse investors. Rather than being a trade off between a forward looking model and a simple approach these features would seem to introduce uncertainties that will make the prediction of charges more difficult, albeit it may reduce the computational burden. These cut-offs in the evaluation period may add to the complexity of the approach rather than enhance its simplicity.

Both networks and generation are long-lived assets. Investors in them recognise the associated uncertainties but truncating the forecasts because of these uncertainties is inappropriate and is likely to introduce an even more significant distortion that an erroneous forecast. We would suggest that the projection behind the charging methodology should extend for a period where the discounting of the future costs renders the forecast irrelevant.

*Recognition of intermittent generation*

*We welcome views on the extent to which it is appropriate to use F factors to calculate the benefit LV generation can provide to the network.*

It is important to recognise that the F factors in P2/6 are contribution factors in terms of energy and may not reflect the contribution a generator can make to the network at times of system stress. It would be better to use a realistic forecast of the support a generator can bring, but in the event of the lack of any data then the F factor may provide a default value.

*Reactive power charging*

*We welcome views on the extent to which SP's proposal encourages EHV customers to make the most of their power factor as well as on their changes to HV/LV reactive power charging.*

The reliance on kVA capacity charges for recovering the costs of reactive power seems too blunt an instrument for dealing with a charging issue where the subtleties could be particularly profound, especially on the EHV network. Loads and generators connecting at EHV will be bound by the terms of their connection agreements to keep their power factors within a specified range and generally close to unity. Network design and users equipment will reflect these requirements.

Users will usually install capacitor banks or a reactor to achieve the design requirement but such equipment can occasionally fail. When it does the user should see a strong signal to reinstate the reactive compensation but there should be no underlying assumption that additional system reinforcement has to be provided. It would therefore appear that a kVArh charge is the more appropriate mechanism for charging for poor power factor at the EHV level rather than relying on a kVA capacity charge.