To generators, distributors,
suppliers, customers and other
interested parties

*Promoting choice and
value for all customers*

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17 June 2008

Dear colleague,

Consultation and impact assessment on Scottish Power's (SP) proposed modifications to their use of system charging methodology: longer term methodology for EHV and revised approach to HV/LV demand and generation charging

Electricity Distribution Network Operators (DNOs) have licence obligations[1] to have in place three charging statements: the statement of use of system (UoS) charging methodology, the statement of UoS charges and the statement of connection charging methodology and charges. The statement of UoS charging methodology outlines the method by which distribution UoS charges are calculated.

DNOs are required to keep their UoS charging methodologies under review and to bring forward proposals to modify the methodology that they consider better achieves the relevant objectives[2].

Before making a modification to a UoS charging methodology a DNO must submit to the Gas and Electricity Markets Authority (the 'Authority')[3] a proposal to modify their methodology stating how the proposal better achieves the relevant objectives. The DNO then makes the modification unless within 28 days the Authority either directs the DNO not to make the modification or notifies the DNO that it intends to consult and then within three months of making that notification directs the DNO not to make the modification.

SP have submitted a proposal to modify their UoS Charging Methodology in order to introduce a long term UoS charging methodology. The proposal represents substantive changes to the existing methodology for calculating UoS charges across LV, HV and EHV connected demand and generation customers in both SP Distribution Ltd and SP Manweb plc's Distribution Services Areas (DSAs). The Authority has decided to consult on the proposed modifications and informed SP of this on 6 June 2008.

[1] Standard licence conditions (SLC) 13 and 14.

[2] The relevant objectives for both the connection and use of system charging methodologies, as contained SLC 13(3) of the distribution licence:

- that compliance with the use of system charging methodology facilitates the discharge by the licensee of the obligations imposed on it under the Act and by the licence;
- that compliance with the use of system charging methodology facilitates competition in the generation and supply of electricity, and does not restrict, distort, or prevent competition in the transmission or distribution of electricity;
- that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable (taking account of implementation costs), the costs incurred by the licensee in its distribution business; and
- that, as far as is consistent with the sub-paragraphs above, the use of system charging methodology, as far as is reasonably practicable, properly takes account of developments in the licensee's distribution business.

[3] Ofgem is the office of the Authority. The terms 'Ofgem' and the 'Authority' are used interchangeably in this letter.

Background

In May 2005 we published a consultation on the longer term charging framework[4] . This called for DNOs to overhaul their charging methodologies to make them significantly more cost reflective and provide a baseline methodology which will endure for years to come. These new charging frameworks were to replace interim arrangements put in place at the beginning of the current price control period[5]. The document stated that the methodology should be:

- Cost reflective;
- Transparent;
- Predictable;
- Simple (at the point of use); and
- Facilitate competition

An update detailing the progress of the structure of charges project was published in April 2007[6] outlining areas for development along with each DNO's progress and target implementation for a long term framework. To date, one distribution company (Western Power Distribution (WPD)) has submitted and implemented a long term framework based on the high level principles above[7].

In April 2008 we published a consultation inviting views on the way forward for the structure of charges project[8]. The consultation document stressed the importance of all DNOs putting in place long term charging methodologies ahead of the start of the next price control period in April 2010 and offered two alternative licence modifications to achieve this deadline. We set out the role long term charging methodologies play in facilitating the efficient development of the network and ensuring that networks do not provide a barrier to meeting climate change targets. In the document we also suggested how the high level principles in our May 2005 document could be amplified in order to guide the DNOs as they develop their methodologies. A DNO working group is currently discussing the drafting of these clarifying principles and the associated licence conditions.

Scottish and Southern (SSE), Central Networks (CN) and Scottish Power (SP) (G3) have been working together to develop a long term methodology. G3's development process has included both informal consultation[9] and independent review[10]. SP's submission is based on the resulting G3 methodology applied to both DSAs owned and operated by SP. The submission excludes Independent Distribution Network Operator (IDNO) charges. We understand that SSE and CN intend to put forward G3 proposals for implementation in April 2009.

Proposed modifications

SP's proposed modification attempts to put in place a long term methodology in line with the principles described above. SP is proposing a Forward Cost Pricing (FCP) methodology to calculate EHV demand and generation reinforcement costs, and the development of a method[11] for the calculation of other costs, the allocation of all costs to customer groups and the scaling of charges to allowed revenues.

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[4] Structure of electricity distribution charges: consultation on the longer term charging framework, May 2005.
[5] Interim charging arrangements took effect on 1st April 2005 based on the outcome of a consultation process which begun in December 2000. A decision document was published in November 2003 proposing that by April 2005 the clearest problems with the current structure would be addressed through interim arrangements, while work would continue in parallel on the development of a longer term solution.
[6] Structure of electricity distribution charges: Update on progress and next steps, April 2007.
[7] WPD were informed of the decision not to veto their proposed methodology on 1st February 2007. The decision letter can be found at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/16857-20a07.pdf.
[8] Delivering the structure of charges project 36/08. Available on our website at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=396&refer=Networks/ElecDist/Policy/DistChrgs.

[9] Structure of electricity distribution charges – G3 consultation paper, which can be found together with the responses at http://www.scottishpower.com/StructureOfChargesProjectG3.htm.
[10] Independent review by Reckon LLP and Frontier Economics which can be found at the same SP link as above.
[11] This method is sometimes referred to as the COG methodology.

The proposal is described in detail in SP's formal submission which is published on our website[12] and is summarised in **Annex 1** to this letter.

In **Annex 2** we set out our assessment of the main issues in relation to the mechanics of the proposed modification. The consultation process is designed to seek views on the modification proposal, whether we have captured the full range of issues raised by the proposal, and the views respondents have in respect of these.

The proposed modifications represent substantive changes to the existing methodologies and as such have an impact on all end-user tariffs.

Due to the number and complexity of the modifications being proposed, we have attempted to simplify the proposals through diagrams and additional explanation. In addition, we have provided supporting analysis to help respondents understand the wider impact of the proposals, presented as part of an Impact Assessment which can be found in **Annex 3** and its supporting schedules.

Initial assessment

Our initial assessment is that this proposal represents a significant step forward in SP's charging arrangements. In particular, it seeks to introduce:

- More cost reflective generator charging arrangements which take account of generator costs and benefits;
- Revised EHV charging arrangements for demand and generation customers; and
- The allocation of certain costs to different customer groups prior to more generic scaling.

We have some initial concerns over some of the effects of SP's proposal. These are detailed in Annex 2. In summary these are centred on:

- Averaging across customer groups and the extent to which this provides adequate economic signals to influence users' decisions;
- The use of a ten year period in EHV charging and whether an alternative period might better reflect asset lives;
- Different treatment between demand and generation (in terms of the size of increments used in the modelling) and the extent to which this is appropriate;
- The lack of IDNO-specific yardsticks in this proposal and the potential conflict with an earlier proposal concerning IDNO charging (see below); and
- The charging volatility within the new approach to HV/LV demand charging, and the extent to which this is an improvement on SP's current approach.

Views sought

We welcome views on the extent to which the issues and effects we have highlighted are material and whether, overall, SP's G3 methodology represents an appropriate balance of the charging principles to provide a baseline methodology for years to come.

In particular, we note and invite views on:

- The transparency of the model and the level of cost reflectivity;
- Whether the model treats distributed generation in an appropriate manner;
- The extent to which the proposals take account of long term, marginal, avoided costs from distributed generation and demand side management[13];

[12] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=419&refer=Networks/ElecDist/Policy/DistChrgMods.

- Whether the degree of averaging in the model is compatible with incremental cost pricing;
- The omission of IDNO-specific yardsticks from this proposal (see below);
- Whether the proposals facilitate the discharge by the licensee of the obligations imposed on it under the Act and by the licence[14];
- The extent to which the proposals are more cost reflective[15]; transparent, predictable and simple than the current methodology;
- Whether SP demonstrate that its proposals facilitate competition in generation and supply and do not restrict, distort or prevent competition in transmission and distribution[16]; and
- To what extend the proposals take account of developments in the licensee's distribution system[17].

Consultees are also asked to consider whether we have correctly captured the main issues raised by, and the impacts of, SP's modification proposals in Annex 2 and 3. We welcome any quantification of impacts as part of responses where possible.

Where in this document we refer to Ofgem or Authority views, this is a reference to our provisional views, and this is subject to further consideration of any points raised in response to this consultation

IDNO charging

SP has already submitted a separate modification proposal concerning IDNO charging and we are currently consulting on this proposal[18]. SP have not identified how their IDNO proposal is linked to this current proposal and the proposal makes no provision for IDNO charging. We understand that SP are now considering submitting an individually considered separate proposal which deals with longer term charging under the jointly developed G3 model and IDNO charging. If we were to receive such a proposal we would be likely to consult on the differences in the interaction of IDNO charging in a G3 model compared to IDNO charging under SP's current model.

We would urge all DNOs to continue developing their UoS charging methodologies to take account of IDNO and longer term charging arrangements. We would also stress that these should not be seen as completely separate projects. If DNOs wish to submit separate proposals dealing with each of these, they should ensure that they have given full consideration to the interaction of the two, both in terms of the mechanics of this process and the timing of implementation.

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[13] We consider this to be a relevant factor in considering whether the proposal better meets the relevant objectives under SLC 13(3)(d). Consultants are asked to note that recital 18 of Directive 2003/54/EC concerning common rules for the internal market in Electricity (the IMED) which provides that distribution charging methodologies should account for marginal and avoided costs.
[14] Standard condition 13(3)(a) of the electricity distribution licence.
[15] Standard condition 13(3)(c) of the electricity distribution licence.
[16] Standard condition 13(3)(b) of the electricity distribution licence.
[17] Standard condition 13(3)(d) of the electricity distribution licence.
[18] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=418&refer=Networks/ElecDist/Policy/DistChrgMods. This consultation closes on 17 June 2008.

Responses to this consultation letter

Views are invited on the issues raised by SP's charging methodology modification proposals from interested parties, including DNOs, IDNOs, suppliers, customers, generators and their representatives.

Views are invited **by Tuesday 29 July**. Where possible responses should be sent electronically to Colette Schrier via e-mail to distributionpolicy@ofgem.gov.uk.

The process associated with modifications to the charging methodologies is detailed within the electricity distribution licence (SLC 13). As the Authority's decision is time bound, please ensure that your comments are received by the date indicated so that they can be fully considered. It may not be possible to consider responses that have been received after this date.

All responses will be held electronically by Ofgem. They will normally be published on our website unless they are clearly marked confidential. Respondents should put confidential material in appendices to their responses where possible. We prefer to receive responses electronically so that they can easily be placed on the website.

Copies of this document are available on our website under the distribution charging modifications area of work[19].

Please contact Mark Askew on 0207 901 7022 if you have any queries in relation to the issues raised in this letter.

Yours faithfully

Rachel Fletcher
Director, Distribution

[19] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx.

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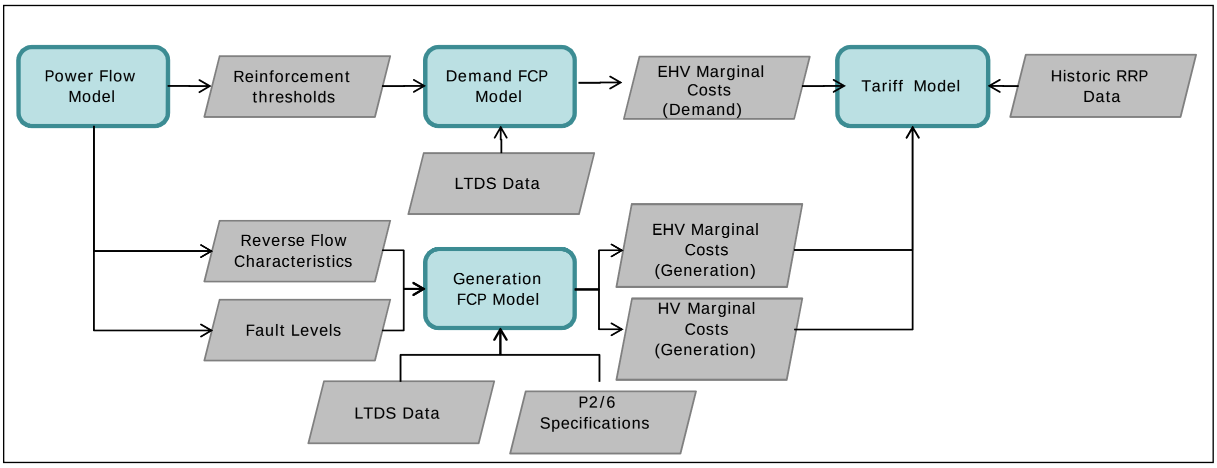
Annex 1 - Proposed modifications

SP are proposing to modify their UoS charging methodology which is used to calculate demand and generation charges for customers connected at EHV, HV and LV levels. These changes represent an attempt to implement a new, long term UoS charging methodology.

SP are proposing to structure their model into four modules, shown in Figure 1.1. A power flow model generates outputs which are combined with LTDS[20] data to calculate the EHV demand induced reinforcement cost and the EHV and HV generation induced reinforcement costs. The remaining costs (HV and LV demand induced reinforcement costs, operations and maintenance (O&M), refurbishment and administration, customer service and billing) are calculated in the tariff model using historic RRP data[21].

Figure 1.1



<u>Power flow model</u>

A power flow model is used for each network group to establish the existing maximum baseline demand, and to increase this by 1% increments until 115% of this maximum baseline. At each increment, the assets requiring reinforcement are identified. The outputs of the power flow model are therefore, the current maximum baseline demand, and for each asset requiring reinforcement, the capacity at which reinforcement is needed and the reinforcement cost.

<u>Demand FCP model</u>

EHV Forward Cost Pricing (FCP) demand and generation charges are calculated at an aggregated network group level.

- *FCP EHV demand reinforcement*

G3 propose that the FCP charges must be such that the total revenue recovered over the ten year period must equal the forecast reinforcement cost.

Initially, the outputs of the power flow model are fed into the demand FCP model, and combined with the LTDS annual growth rate for each network group. The growth rate is used to calculate the number of years until reinforcement is needed. Only those reinforcements projected to occur within ten years are considered.

[20] Long term development statement which is prepared by DNOs in accordance with SLC 25. The statement contains information about the future planning design of the network.
[21] SP state that LV generation will not have a cost impact on their network.

A charging function then calculates a £/kVA/annum charge rate for each component's reinforcement. The charging function works by ensuring that the total recovered by the time of reinforcement is equal to the change in the NPV of the cost of reinforcement i.e. the difference in the cost of reinforcing the asset today and the cost of reinforcing the asset in the year when reinforcement is triggered. The function uses the entire demand of the network group at the time of requiring reinforcement. This function is applied to all assets which require reinforcement in each of the ten years.

SP employ a time banded approach to recognise the potential for demand profiles other than peak demand to contribute to reinforcement. For EHV demand charging, SP only use the time period of peak demand to calculate the FCP charge rate.

- *FCP input for HV/LV demand reinforcement*

For HV/LV charging, the model calculates asset reinforcement charge rates for four time periods. The probability of a given time period contributing to the period of peak demand is based on existing network group demand profile. This probability is then applied to each capacity at which reinforcement is required. The relevant proportion of that capacity is used to calculate a charge rate for each of the four time periods. The four single period charge rates are scaled to ensure that the total revenue recovered via their sum total is equal to the revenue recovered with the single period of maximum demand. The rates for each network group's time periods are averaged across all network groups and used to calculate the tariff rates for HV and LV. The model takes total FCP charge for each time period as the sum of the rates for all forecast reinforcements for that time period.

<u>Generation FCP model</u>

- *EHV / HV generation reinforcement*

EHV generation reinforcements are calculated using a separate model to EHV demand but use inputs from the EHV demand model. The model retains the 10 year forecast period for reinforcement costs used in the FCP demand model and also continues to calculate EHV charges at an aggregated network group level. As for the EHV demand model, total generation induced reinforcement costs are spread across total expected generation to derive a set of network group annual £/kVA charges.

However, beyond these high-level similarities, there are significant differences between the generation and demand FCP models. The key differences are as follows:

- To capture the 'lumpiness'[22] of generation connections, the generation model forecasts required reinforcement costs by adding a test size generator (TSG) to each network group;
- The TSG is the same for each voltage level across all network groups. The generation model does, however, scale the reinforcement costs induced from a TSG connection by the probability of such generation actually connecting to a network group. This gives a measure of the expected reinforcement costs for the network group incurred by generation over the next ten years. To derive the probability of the TSG connection, it is assumed that total new generation capacity will be equivalent to 30% of current demand; and
- The generation model calculates when expected reinforcements will be required based on a TSG connecting within the next ten years. The model assumes a linear growth rate for the TSG connection over the ten year period based on an equal probability of the TSG in each of the ten years. This is also used to derive total network group generation over the ten year period.

The generation model and its key features are considered in more detail in Schedule 6 below.

[22] By lumpiness we mean the potential for a new generator to connect which will increase the generation capacity in a step phase, rather than gradually.

Generation benefits are calculated by multiplying the demand costs for that network group's voltage level, as well as the voltage levels above the point of connection, by the P2/6 Generation Contribution Factors at the voltage of connection. Where the benefit is greater than the cost, then SP's model allows for negative charges for generation.

- *LV generation reinforcement*

LV generators are not charged for connecting to the network and will therefore only recognise the benefit in line with the method used for EHV and HV generation (including negative charging).

<u>Tariff Charging Model</u>

The tariff model identifies relevant customer yardstick groups, where each yardstick group relates to either demand or generation, and is associated with a specific voltage level. The model then allocates all appropriately identified costs to the various yardsticks and uses this to derive the final tariffs.

Specifically, the tariff model consists of three stages:

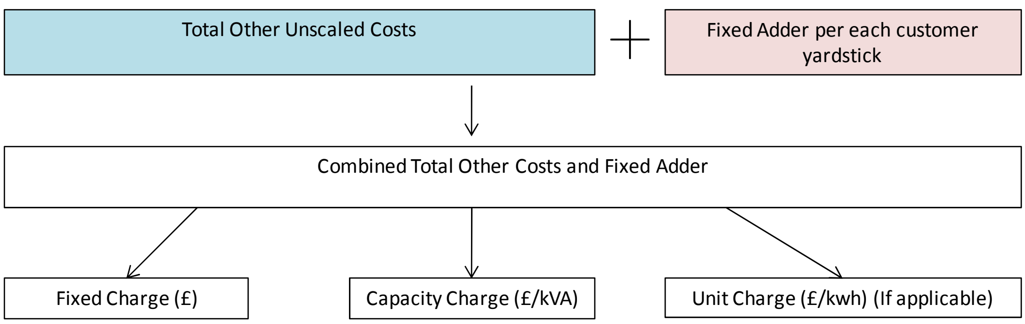
a) Calculating other costs for all voltage levels, to be recovered for demand and generation, including operations & maintenance, administration and customer service, and then allocates these to the customer yardsticks;

Total Other Unscaled Costs =
O&M + Refurbishment + Pass-Through + Customer Service
(In addition, FCP charges for all voltage levels other than EHV)

b) Calculating a fixed voltage level adder by scaling to recover the total allowed revenues; and

Fixed Adder per each customer yardstick (including EHV)

c) Setting the final tariffs by combining the total other unscaled costs and the fixed adder;



Therefore, the final tariff consists of fixed, capacity and unit charges per each customer yardstick.

a) *Calculating and allocating other costs*

A demand profile is used for each customer yardstick with estimates for the group's forecast peak demand at each voltage level and time period. These demand estimates are scaled up by Loss Adjustment Factors to estimate the demands placed on higher voltage levels by each yardstick group.

Operations & Maintenance costs (O&M) – These include inspection, maintenance and fault costs. The model uses a rolling average of historical figures from the Regulatory Reporting Packs (RRP), and adjusts these for RPI. These costs are attributed to each customer yardstick based on

Demand Estimation Coefficients (DECs) to determine their contribution to the forecast maximum demand from the demand profile.

Refurbishment costs – The model takes a rolling average of historical RRP refurbishment cost data, and adjusts for RPI. These are attributed to each customer yardstick based on DECs to determine their contribution to the forecast maximum demand from the demand profile.

Pass-Through costs – These include NGET exit charges and licence fees. Each customer yardstick is allocated its equitable share of exit charges based on their contribution to the maximum demand at the NGET boundary. Licence fee cost are attributed based each customer group's forecast customer numbers.

Customer Service costs – These use the RRP table figures and are attributed to customer yardsticks based on forecast customer numbers.

In addition, the FCP costs from the Demand Cost model are also used in the Tariff model. For EHV customers, the FCP costs are used on a network group basis e.g. a customer connecting to a given network group will use that network group's FCP charge. For HV and LV, the FCP costs are averaged over all network groups and allocated to four time periods using the customer yardstick demand profile.

Therefore:

Total Other Costs for HV/LV = O&M + Refurbishment + Pass Through + Customer Service + FCP Charges

Total Other Costs for EHV = O&M + Refurbishment + Pass Through + Customer Service

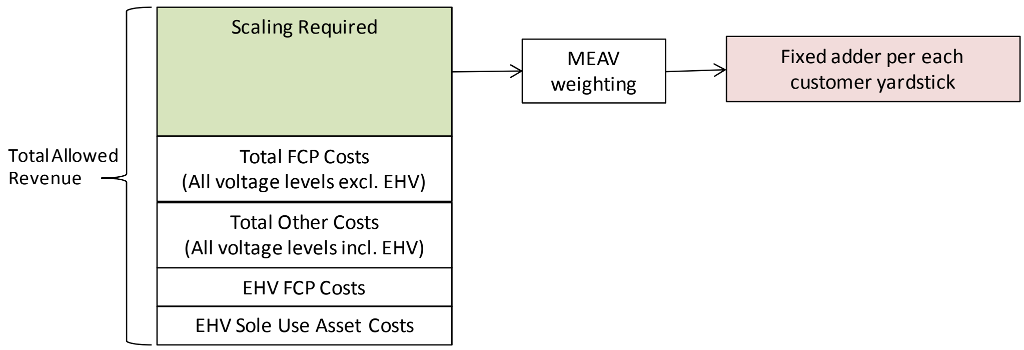
Analysis on the impact of allocating costs in this manner can be found in Schedule 3 and figure A.7.

b) Scaling

There are separate allowed revenue amounts for demand and generation, and SP reconciles the costs obtained for each of these with their corresponding allowed revenues.

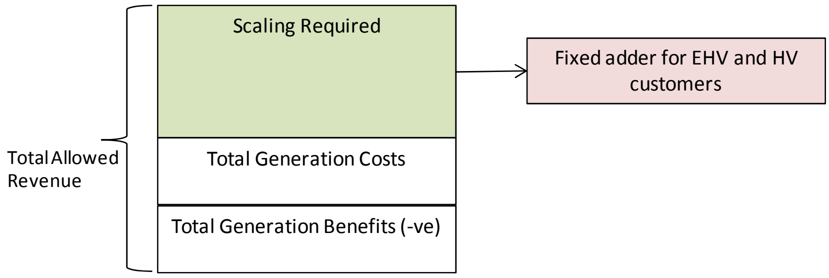
For demand, scaling of the modelled output to allowed revenue is achieved by calculating a 'per kVA, per voltage level' adder. Initially, total model costs are calculated by combining the following costs: FCP charges for all customer yardsticks voltage levels (excluding EHV), other cost charges for all customer yardstick voltage levels as well as a EHV FCP and sole use asset costs for all network groups. The difference between this and the allowed revenue provides the amounts of scaling required. The scaling required is then apportioned on the basis of the estimated Modern Equivalent Asset Value (MEAV) of the assets at the various voltage levels. This results in a different per kVA adder at each customer yardstick network voltage level. The impact of this is illustrated in schedule 3.

Figure 1.1 *Demand scaling*



For Generation, a fixed kVA adder is also used to scale generation output to allowed revenue using an approach similar to demand, but without the weighted MEAV allocations.

Figure 1.2 *Generation scaling*



Total net costs are calculated by the summation of generation costs and benefits for all EHV and HV customers. The difference between this value and the total allowed revenue provides the necessary scaling required. This difference is then apportioned based on demand for the EHV and HV levels to provide a fixed kVA adder.

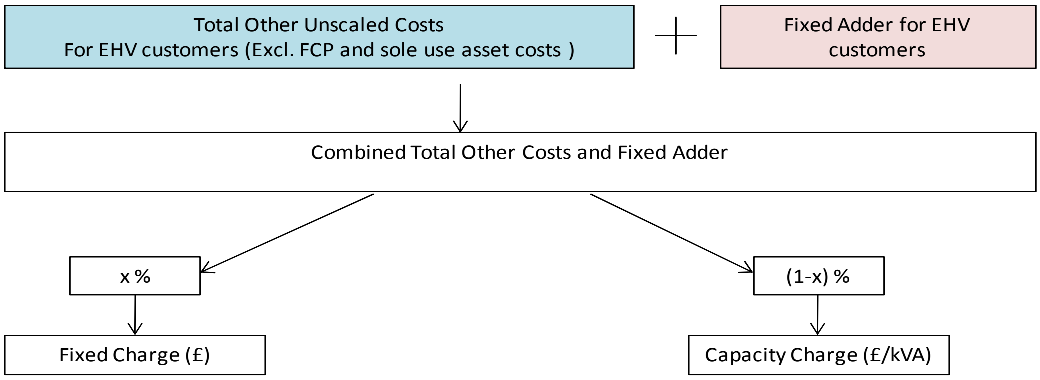
c) Setting the final tariffs

Final tariffs are set by aggregating the different cost elements within each customer yardstick, and dividing this proportionately to create the different tariff elements.

For EHV, total other costs (excluding the site-specific FCP and sole use asset charges) is combined with the fixed adder and then shared between the fixed and capacity charges, as shown in Figure 1.3 below.

The percentage allocation (x%) to the fixed charges is determined by the fixed costs' contribution to the total unscaled costs. The fixed charge recovers customer service costs, and the capacity charge recovers all other business costs. Both these charges are divided by the number of customers connected at the EHV voltage level, and the Capacity charge further divided by the average capacity of the EHV voltage level.

Figure 1.3



Therefore, all EHV network customers will have the same fixed (£) and capacity (£/kVA) charge. In addition, each customer has site-specific £/kVA/annum FCP charge and a sole use asset charge, which are not scaled.

Similarly, for HV/LV customer yardsticks, total costs (including FCP costs) are combined with the relevant fixed adder. This is then allocated between the fixed, capacity and unit charges for each customer group. Therefore, all network groups within a given customer yardstick all have the same fixed (£), capacity (£/kVA) and unit charge (£/kwh).

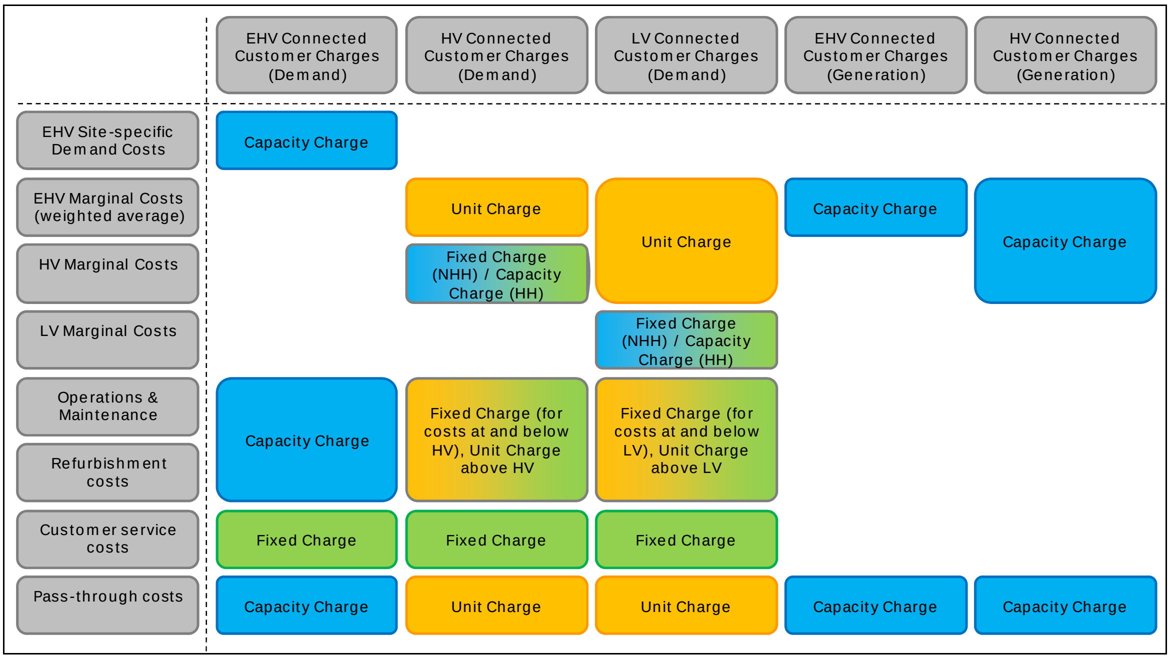
Figure 1.4 shows a high level summary of each customer yardstick's tariff elements. HV and LV demand sites have fixed, capacity and unit tariff charges whereas generation sites have only capacity charges.

EHV customers have site-specific fixed and capacity charges, as they are made up of the following components:

Final Capacity Charge (£) = Customer Capacity * (Capacity Charge + FCP Charge)

Final Fixed Charge (£) = Fixed Charge + Sole Use Assets Charge

Figure 1.4



Annex 2 – Issues

2.1 SP's proposals represent a number of fundamental changes to the UoS methodology. These have been designed in an attempt to implement a methodology which better meets the relevant objectives[23]. The Authority has identified a number of areas where we feel that the methodology may raise certain issues. This consultation seeks views from consultees on the materiality or otherwise of the issues we have identified, and any other relevant issue respondents would like the Authority to consider in reaching its final decision. Issues are set out in this annex along with analysis in the supporting schedules at the back of the document.

2.2 As set out in our cover letter, we also see this consultation as an opportunity to gather views from industry on the trade off between the charging principles which are the basis of the structure of charges project[24]. We have identified the following areas as being pivotal in the debate over the practical application of these charging principles:

1) Cost reflectivity, including averaging

- The use of network group aggregation and 'different increments'
- The use of a test size generator in setting EHV/HV generation charges
- Varying the size of the test size generator
- Revenue reconciliation
- The use of historic RRP data for HV/LV demand charging
- Coincidence with system peak

2) Different approaches to setting demand and generation charges

3) The extent to which the use of a ten year recovery period impacts limits the forward looking aspect of the model

4) Other issues

- IDNO charging
- The use of P2/6 in recognising the benefit of intermittent generation at LV
- Reactive power charges.

Cost reflectivity and the extent to which the model makes 'averaging' assumptions

2.3 As part of our 2005 Consultation on the longer term charging framework Ofgem outlined the merits of an incremental marginal charging approach which is forward looking[25]. Consultees should note that the IMED provides that distribution tariffs should be non discriminatory[26], which provisions are reflected in SLC 13 and SLC 14 of the distribution licence. Recital 18 of the IMED also provides that in approving tariffs, or the methodologies underlying the calculation of tariffs, national regulation authorities should ensure that distribution tariffs are non-discriminatory and cost reflective[27] and should take account of the long term, marginal, avoided costs from distributed generation and demand side management measures.

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[23] See footnote 2 detailing the relevant objectives.

[24] In referring to charging principles we principally mean cost reflectivity, simplicity (at point of use), transparency, predictability, facilitating competition as well as accurately reflecting forward looking costs, incentivising the efficient use and development of the network and accommodating the introduction of generator use of system charges better than existing models. As noted previously these principles are detailed within various documents, for example the April 2008 'Delivering the electricity distribution structure of charges project' document (36/08). http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=396&refer=Networks/ElecDist/Policy/DistChrgs

[25] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/10763-13505.pdf.

[26] EU IMED Article 23 recital 18.

[27] This aspect of the IMED is reflected in the relevant objectives – SLC 13(3)(c)

2.4 We seek views on whether a number of aspects in SP's proposal provide a practical balance between cost reflectivity Vs stability and cost reflectivity Vs transparency and predictability.

i) The use of Network group aggregation and different increments

2.5 SP's proposal calculates an FCP £/kVA charge rate. This rate is based on the total cost of reinforcements that the total network group capacity will trigger at 1% increments of current demand. Their first step in calculating this rate to take the change in the NPV (Net Present Value) of that reinforcement from the base year, to the NPV in the year when the power flow model indicates reinforcement will be needed. This value is then divided by the total demand on the network group in order to aggregate across the network group. Schedule 5 outlines the difference in this approach from an approach which provides a £/kVA charge rate for each asset or node within the network group[28]. Figure A.8 in Schedule 5 illustrates the range of charges which may exist within a network group SP instead chose to aggregate.

2.6 We note that Reckon's report[29] concludes that SP's proposed approach is capable of providing locational signals that encourage loads to locate where they can supported with less network investment. However, the report also goes on to conclude that SP's approach is likely to understate these locational signals. Reckon suggest that this could lead to insufficient pressure on customers to locate load where total cost would be minimised.

2.7 We also note that Frontier's report comments that the use of zones (rather than nodes) represents a sensible boundary for the derivation of locational charges for the EHV network. More granular locational signals, would in their view, substantially increase the complexity and unpredictability of the charging regime.

2.8 We note that a different increment of demand is used for each network group rather than taking a set increment of demand. The increment used is dependent upon the total demand within the network group and therefore the increment used for each network group will be different in terms of its MVA value. Schedule 2 includes illustrations showing the different increments used across network groups.

2.9 We note that SP use a charging function which comprises the second step in their FCP model. This function is used to impute the result of the first step into a pricing function. This function ensures that charges change year on year and increase as time to reinforcement decreases. We note that Frontier Economics' report[30] comments that the charging function is used to shape the pricing over the period of cost recovery. They also comment that this seems sensible and has a number of desirable properties including stability. However, Frontier comment that the use of the charging function to recover the change in the NPV of reinforcement has no clear economic ground.

We welcome views on the issues in this section:

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

- ***The extent to which the use of network group 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 charge pricing function.***

[28] This nodal charging approach was employed by WPD. WPD's longer term methodology proposal was approved by the Authority in February 2007.
[29] Reckon LLP undertook a report on the Locational signals of an FCP methodology. The report is available on SP's website at http://www.scottishpower.com/uploads/ReckonG3paper1Feb2008.pdf
[30] Report by Frontier Economics: "Review of distribution use of system charging methodology". Available at http://www.scottishpower.com/uploads/FrontierEconomicsG3DUoSChargesFinal250308.pdf.

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

2.10 SP's approach to generation is discussed in more detail in Schedule 6. However, SP have stated that the addition of generation to the network tends to be lumpy and that generation can not be adequately reflected by an average growth rate. Consequently, SP have chosen to take the increment of a test size generator (split over 10 years) in assessing when assets require reinforcement.

2.11 SP use the 85th percentile of all generation capacities at each voltage level to calculate the size of the test size generator. We note that this includes all generation, including that which was connected pre-2005 under a deep connection charging regime.

2.12 SP's approach also assumes the same probability of a test size generator connecting at every network group within each voltage level. This has an averaging impact on the FCP aspect of the charge. The approach assumes that there is an equal chance of a generator connecting to each network group. It also assumes the probabilistic increment is appropriate for all network groups.

2.13 We note that Frontier outline the strengths of test size generator and probability analysis, commenting that it constitutes a sensible way of accounting for the inherent uncertainty that exists about 'lumpy' future generation connections. They comment that the approach is transparent and provides a simple solution to a complex area.

- ***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 any 'lumpy' connection of generation.***

iii) Varying the size of the test size generator

2.14 Under SP's proposals the size of the standard test size generator at each voltage level will vary according to where the 85th percentile of current and planned generation capacities lies. We undertook analysis to assess the impact of varying the size of the test size generator. Table A.6 in schedule 6 illustrates the variations between the size of the test size generator at each voltage level.

2.15 Our analysis suggests that as the size of the test size generator increases, the charge rate falls, whilst as the size of the test size generator falls, the charge rate increases. The full analysis of this is available in Schedules 1 and 2.

2.16 The results of this analysis appear to be counter-intuitive. As the increment used i.e. the size of the test size generator decreases, the charge rate should fall, and as the increment increases we would expect the charge rate to rise. The result is a consequence of reinforcement costs being spread across total generation for a network group and by the scaling of reinforcement costs in the generation model by the probability of the test size generator connecting (described in Annex 1 and Schedule 6). As larger size generation connects, the probability that the TSG will connect falls and total generation for a network group increases, therefore the charge rate decreases.

- ***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.***

iv) Revenue reconciliation

2.17 SP apply some form of revenue reconciliation (or scaling) on the output of their Demand model to ensure that their total revenue matches up with allowed revenue. This is set out in Annex 1.

2.18 Firstly, the COG model allocates various costs, including O&M and refurbishment costs, to the different customer groups. These costs are then aggregated to create a final total cost for each customer yardstick. This total cost is scaled by applying a fixed adder, and then proportionately divided into the fixed, capacity and unit charges as relevant. The impact of this is shown in Schedule 3. To calculate the fixed adder, demand scaling uses a weighted MEAV approach, whereas generation scales directly to allowed revenue based on the proportionate demand at EHV and HV levels.

2.19 The COG model allocation results in different fixed adders for each customer yardstick. Consequently, the actual scaling approach varies between demand and generation. We note that Frontier state there are two potential concerns with the scaling approach. First, they highlight that large amounts of revenue are being recovered through scaling. Secondly they observe how weighting scaling factors for demand charges by MEAV at each voltage level may result in distortions between charges at different voltages.

- ***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.***

v) Use of historic RRP data in HV/LV charging

2.20 SP propose to use historic data RRP data as the basis for calculating charges for HV and LV demand customers. We note that in using historic averages to calculate current charges, the model is not forward looking. The proposal results in customers paying for the historic use of the distribution system, rather than calculating how a set increment can impact upon the distribution system given its current use.

2.21 SP state that they will use a rolling average of RRP data in order to smooth out fluctuations between years and deliver stable predictable charges. It is not clear how many years SP will use in their rolling average of RRP data. At present only 2 years' comparable data is available. We note the potential for fluctuations between yearly RRP data which may lead to volatility. This may be more prevalent over the first few years of the model when there is not a large pool of RRP data to average out any anomalies.

2.22 We note that SP consider that the use of RRP data increases the transparency of their model and Frontier recognise this in their report. Frontier also raises concerns over the reliance on recent historical trends to forecast future network developments but stresses that it is simple, transparent and minimises the scope for subjective decision making.

- ***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.***

vi) *Coincidence with system peak*

2.23 Distribution charging frameworks can potentially have an important role in encouraging energy demand management. Charging structures that reflect customers' coincidence to peak demand and which incorporate time of day and/or seasonal influences can help encourage more efficient utilisation of the network.

2.24 For HV/LV customers, SP are proposing to create four time period FCP rates using average network group level demand profiles. In contrast, they are proposing to use only the period of system maximum demand for EHV customers.

- ***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.***

Different approaches between demand and generation

2.24 Ofgem considers symmetry[31] between charging methodologies for demand and generation network users to be important where cost drivers are the same.

The descriptions in Annex 1 and Table 1 below suggest that cost drivers are inconsistent between demand and generation FCP models, but also highlight:

- the modelling mechanics used to derive demand and generation network user charges; and

- the costs and benefits that are included in final network charges.

2.25 We consider that at a detailed level the manner in which charges are formulated for demand and generation are different. In particular we wish to highlight the different size of increment and probability used in calculating reinforcement costs for generation but not demand.

Table 1

	Demand	**Generation**
Increment	1% of existing demand within the network group	A test size generator for each voltage level
Growth rate	Varies across network group but generally 1%. Constant increment used	Probabilistic approach based on forecast growth in generation from a DTI/Ofgem report and the cumulative probability of a test size generator connecting at each voltage level in every one of the ten years. Increment will vary depending upon the size of generators which connect on to the network
Aggregation	Charges on a network group basis	Increment determined at voltage level but applied on a network group basis
Locational	At EHV	At EHV
Model period	10 yrs	10 yrs

[31] By symmetry we mean the same treatment of equal and opposite increment.

Cost drivers	Thermal capacity	Fault Levels; Reverse power-flow
Negative charging	No account taken of where demand could defer generation reinforcements	Account taken of how generation can defer demand reinforcement in a ten year period. Benefits are 'added back' to derive final charge
Scaling	Weighted by MEAV	Not weighted by MEAV

2.26 Schedule 6 outlines the differences in how a 10MW demand and generation customer is treated and different steps used in the calculation of the charges for each. It appears that customers may not be treated consistently because:

- generation benefits are 'added back' to derive final generation charges rather than reducing reinforcement costs in a more holistic manner relative to demand;
- the demand and generation charges reflect different forward looking increments to the network group.

- ***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?***

Use of a ten year recovery period

2.27 For demand and generation at EHV SP state that they will use a 10 year period to recover the cost of reinforcements[32]. Any reinforcement where power flow analysis indicates will occur after ten years is not considered and therefore produces a zero FCP charge rate. We note that this limits the forward looking aspect of the model.

2.28 Frontier state that a more cost reflective approach might be to take a 20 year horizon. However SP suggest that beyond ten years growth rates may not be known. SP also stress that the economic signals the model should send surround those assets which are close to full capacity (i.e. which will require reinforcement within 10 years).

2.29 As described in Annex 1, the benefit an EHV or HV generator can have on the network is assessed by looking at the demand reinforcement which it can defer. As SP's model only recognises demand reinforcements which will occur within 10 years, it can only recognise the benefit generation can have where demand reinforcement is needed within 10 years. Where no demand reinforcement is due within ten years, the generator benefit becomes zero.

2.30 We also wish to highlight the potential for tariff jumps within the model as the connection of lumpy demand may cause an asset to jump from being for example 11 or 12 years away from reinforcement (and therefore having no FCP charge) to being 6 or 7 years away from reinforcement which will then produce an FCP charge.

- ***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?***

[32] SP's modification report is not clear whether they cap generation cost at 10 years, but our analysis of their model indicates that they cap generation to 10 years.

- ***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.***

<u>Further issues</u>

2.31 We view the issues above as being fundamental in assessing the balance between charging principles. In addition to these we have identified some further issues with SP's proposal that we would like consultees to consider and provide views on.

IDNO charging

2.32 SP's proposal does not include details of how they would charge IDNOs. They state that the principles of the current IDNO charging proposal are fully compatible with the G3 methodology but do not demonstrate how the two proposals interact[33]. Given that the Authority has recently consulted upon an SP IDNO charging proposal, we are very concerned that should the IDNO proposal be approved, that the effect of this proposal may be to strip out the IDNO charges.

Recognition of intermittent generation

2.33 Annex 1 outlines how SP propose to take into account the benefit which LV generation can have on the network. This benefit is multiplied by the P2/6 factor (F factor).

2.34 We note that other distributors current development work on generator charging employs a coincidence factor rather than an F factor to assess the benefit of the generator will provide at LV. The coincidence factor takes account of when an intermittent generator may not be generating.

- ***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.***

Reactive power charging

2.35 SP propose to alter their approach to charging for reactive power at HV/LV. They have moved to an approach which is "broadly similar" to that of ENW. SP highlight that they propose to charge EHV customers on a purely kVA basis. The FCP charge is fed into the kVA capacity charge. SP state that this provides EHV users with an incentive to make the most of their power factor and therefore do not levy reactive charges on EHV customers.

- ***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.***

[33] SP's IDNO modification report and Ofgem's subsequent consultation are available at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=418&refer=Networks/ElecDist/Policy/DistChrgMods

Annex 3 – Impact Assessment

Objectives

3.1 The Authority will make its decision on SP's modification proposal in light of the relevant licence objectives set out in the electricity distribution licence (SLC13), the Authority's principal objective and its statutory duties and obligations. The purpose of this consultation is to seek views on the proposed modification and the associated impacts. To assist this process, we have included analysis of the impact of this proposal to help respondents understand the potential consequence of the modification. The schedules attached to this document provide some context and analysis to build upon the issues highlighted in Annex 2.

Background

3.2 SP's proposed modifications are designed to implement a methodology which better meets the relevant objectives. It also recognises and responds to the need to replace the existing UoS charging methodology with a long term solution in line with the high level principles:

- Cost reflectivity;
- Facilitation of competition;
- Predictability;
- Simplicity at the point of use; and
- Transparency.

3.3 In designing modifications in line with these principles, we assume that SP are hoping to implement a methodology which more accurately attributes costs to and recovers costs from each customer whilst at the same time allowing competition and allowing customers to reasonably estimate what their UoS charges will be.

3.4 SP state that their methodology is more cost reflective due to the introduction of locational EHV charging, their approach to time periods and the use of RRP data for HV and LV reinforcement costs, refurbishment, O&M and Admin, Customer Service and Billing. The cost allocation methodology as part of the cost allocation (COG) model and the approach to revenue scaling is also claimed to be more cost reflective. SP also state that the use of RRP data makes the methodology more transparent. Predictability is said to be improved by the FCP methodology and averaging approach used on the RRP data.

3.5 The Authority has taken the decision to consult on a number of issues to establish the extent to which the methodology achieves what it sets out to do in terms of the high level principles and ultimately the relevant licence conditions. These issues are set out in Annex 2 with further analysis provided in the schedules to this Annex.

Options

3.6 We have an obligation to respond to SP's proposal within a decision to veto or not to veto the modifications. There is no scope to amend or apply conditions to the proposed changes. Following this consultation, the Authority will therefore need to decide to either:

- Veto the proposal and maintain the existing UoS charging arrangements;
- Not veto the proposal and allow the implementation of the proposed changes from 1 April 2009.

3.7 This Impact Assessment provides the analysis which has led to the identification of the issues which have been raised as part of Annex 2. A summary of this analysis is presented here as a starting point aiming to help respondents begin to understand the implications of the proposed modifications.

Impacts, Costs and Benefits

Competition Assessment

3.8 The proposed modifications will have an impact on suppliers, generators and ultimately end customers. Charging methodologies should be developed and designed to encourage and efficient use of the network. In Annex 2 we have asked for views on whether SP's proposal achieves this. Developments in the methodology may cause suppliers to offer more innovative products to customers. SP have also proposed not to include LV generator costs whilst the P2/6 generation contribution factor remains at zero and are recognising generation benefit through negative generation charges. More cost reflective charging for distributed generation connected at EHV, HV and LV should act to encourage competition amongst generators.

3.9 Some of the proposed changes may to lead to more volatile price signals than currently. Some suppliers and generators have claimed that volatility could have a negative impact on competition. Whilst SP's approach may reduce price swings by charging across network groups, we note that the proposed methodology has the potential to cause tariff jumps. Where new demand connects onto the network group, it may cause a steep rise in total demand. For example (as noted in Annex 2) this could have the effect of bringing forward reinforcement not due for 11 or 12 years (and therefore not producing a FCP charge) to 7 years. At 7 years the reinforcement will trigger an FCP charge and existing customers may experience a tariff jump.

3.10 Transparency and predictability are key elements in allowing generators and suppliers to calculate and quote costs to their existing and potential customers and therefore in promoting competition. SP propose using averaged RRP data to calculate a large portion of their costs in order to increase the transparency and predictability of inputs (and therefore outputs) to their model. This is another area on which we welcome views as part of Annex 2.

Environment

3.11 Whilst we have not attempted to quantify the environmental costs and benefits of the proposed modifications a qualitative evaluation suggests that charging frameworks which accurately reflect locational costs and a customer coincidence to peak demand encourage high utilisation of the network at all times and at all locations. This in turn would generate benefits to the environment and should also lead to lower fixed losses associated with network equipment. We have welcomed views on the extent to which SP's proposed modifications accurately reflect both coincidence and locational charges.

3.12 Similarly, more cost reflective charges for generators and the recognition of generation benefit is expected to encourage more distributed generation, a large proportion of which is expected to come from renewable, low carbon sources. In Annex 2 we raise the question of whether SP's proposal provides sufficient recognition of the benefit generation can have on the distribution system.

Security of supply

3.13 Electricity distribution networks are designed to meet security standard P2/6. Where possible, SP's proposed methodology uses P2/6 in the power flow model to both determine reinforcement needs and identify the reinforcement types. The P2/6 generation contribution factor is also used a proxy for a generators coincidence with the production driving the reinforcement need.

Health and Safety

3.14 We consider that the effects of this proposal have no health and safety implications.

Customer Costs

3.15 As the proposed modifications represent significant changes to SP's charging methodology for EHV, HV and LV connected customers there will be an impact on tariffs for all customers. This includes domestic tariffs, small and large businesses. An analysis of current and proposed charges is set out in figures 3.1 and 3.3 (below)[34].

***Figure 3.1* – Tariff Analysis for SPD**

SPD		Fixed Charge 1 (p/MPAN/day)	Day Unit Charge 1 (p/kWh)	Night Unit Charge 1 (p/kWh)	Capacity Charge 1 (p/kVA/day)	Reactive Power Charge 1 (p/kVArh)	Sample Tariff (£)	
Current charges[35]	Domestic Unrestricted	5.71	1.64	1.64			£54.54	
	Domestic Day/night	7.68	1.86	0.56			£59.31	
	12hr Off Peak			1.00			£5.34	
	Business Single rate	23.40	1.78	1.78			£121.99	
	Business Evening & Weekend	27.99	3.02	0.87			£157.38	
	NHH MMD LV <100kW (PC5-8)	84.93	1.65	0.26			£374.42	
	NHH MMD HV<100kW (PC5-8)	655.63	0.76	0.76	1.02		£20,571.45	
	HH LV	44.38	1.30	0.16	1.88	0.28	£206,371.59	
	HH HV	655.63	0.76	0.18	1.02	0.17	£249,051.45	
								% Swing
Proposed charges	Domestic Unrestricted	10.87	1.21				£58.08	6.48
	Domestic Day/night	7.74	1.72	0.06			£54.73	-7.72
	12hr Off Peak			0.91			£4.86	-9.00
	Business Single rate	51.79	1.23				£207.74	70.29
	Business Evening & Weekend	42.55	1.64	0.04			£205.39	30.50
	NHH MMD LV <100kW (PC5-8)	269.18	0.91	0.98			£1,028.92	174.80
	NHH MMD HV<100kW (PC5-8)	295.01	0.24		0.00		£4,628.79	-77.50
	HH LV	15.23	1.07	0.06	4.50	0.27	£174,675.59	-15.36
	HH HV	16.96	0.36	0.00	4.13	0.16	£118,681.50	-52.35

3.16 Substantive changes in tariffs for both SPM and SPD include those for NHH HV customers due to a much higher fixed charge and flatter profile applied to the calculation of day and night unit charges. Restricted business customers also see large tariff changes, the extent and direction of which varies between SPD and SPM. Domestic unrestricted tariffs increase whilst restricted tariffs go down under the proposals. Schedule 4 demonstrates the swing between individual components of the tariffs in both the SPM and SPD regions.

3.17 Some EHV customers can expect increases in their tariffs whilst others can expect decreases. SP's modification report (p.57 and p.59) sets out the change in charges for site specific customers under their proposal. The range of charge changes is set out in figure 3.2 below:

[34] Assumptions in this analysis are based on a NHH LV consumption of 4110kW, a NHH MMD LV consumption of 10,000kW and HH consumption at LV of 100,000kW and at HV of 200,000kW. All LV capacities are taken as 100kVA and all HV capacities are taken as 800kVA.

[35] Charges from 1 April 2008.

Figure 3.2 – EHV tariff analysis

	Range of % change current vs. proposed	
	EHV demand	EHV generation
SP Manweb	-85.07% to 102.32%	N/A
SP Distribution	-36.39% to 22.37%	-11.17% to 25.75%

It should be noted that for SPD's network in particular only a small proportion of EHV customers are in network groups requiring reinforcement and therefore benefit from a zero reinforcement (FCP) charge.

Figure 3.3 **– Tariff analysis for SPM**

SPM		Fixed Charge 1 (p/MPAN/day)	Day Unit Charge 1 (p/kWh)	Night Unit Charge 1 (p/kWh)	Capacity Charge 1 (p/kVA/day)	Reactive Power Charge 1 (p/kVArh)	Sample Tariff (£)	
Current Charges	Domestic Unrestricted	3.63	1.49	1.49			£43.87	
	Domestic Day/night	4.17	1.64	0.54			£43.05	
	Off Peak C			0.67			£3.58	
	Business Single rate	8.43	1.42				£52.36	
	Business Evening & Weekend	14.14	1.57	0.37			£77.46	
	NHH MMD LV <100kW (PC5-8)	51.02	1.25	0.24			£235.59	
	NHH MMD HV<100kW (PC5-8)	413.33	0.83	0.13	1.28	0.3	£18,206.25	
	HH LV	29.05	1.07	0.19	1.37	0.3	£172,346.43	
	HH HV	413.33	0.83	0.13	1.28	0.2	£264,446.25	
								% Swing
Proposed Charges	Domestic Unrestricted	8.16	1.19				£47.88	9.14
	Domestic Day/night	9.21	1.45	0.12			£56.31	30.81
	Off Peak C			1.31			£7.00	95.52
	Business Single rate	31.6	1.2				£133.59	155.12
	Business Evening & Weekend	50.51	1.16	0.13			£202.70	161.67
	NHH MMD LV <100kW (PC5-8)	187.68	0.97	0.11			£722.35	206.61
	NHH MMD HV<100kW (PC5-8)	125.45	0.3	0	0	0.29	£4,897.89	-73.10
	HH LV	8.9	0.9	0.08	2.98	0.29	£146,094.09	-15.23
	HH HV	9.1	0.39	0.39	2.84	0.19	£125,432.63	-52.57

DNO Costs

3.18 It is not expected that there will be significant costs associated with SP implementing the proposed modifications. The models have already been developed and applied to SPD and SPM and need to be re-run in setting indicative and final charges. We are not aware that any costs would be associated with implementing the new tariffs in the settlement system.

Benefits

3.19 In attempting to build a model which better meets the relevant licence objectives a number of benefits are expected in line with what the licence conditions and structure of charges project is striving to achieve. A more cost reflective methodology would mean customers and generators pay charges which are more representative of the costs incurred by the DNO which result from their use of the distribution network. In addition, the way in which these costs are allocated and charged for are designed to create signals to customers encouraging a more efficient use of the network. A cost reflective methodology attempts to create a network which is efficiently utilised by influencing the behaviour of those for whom UoS charging is an active consideration in setting their demand profile and location. SP try to achieve this by encouraging the expansion of EHV demand in locations which will not trigger reinforcement. Annex 2 asks for views on the extent to which SP achieve such benefits in their proposals.

Risks and unintended consequences

3.20 The main risk comes from the possibility that the proposed modifications are implemented and do not better meet the relevant licence objectives. It is for this reason that a full consultation and analysis has being carried out as part of this consultation. This process allows the Authority to consider all issues in an informed way ahead of making a decision based on the licence objectives. In this way, this risk is minimised.

3.21 Risks can arise if methodologies containing assumptions regarding emerging industry trends are implemented and these trends are subsequently not realised. Where possible, the G3 methodology has based such assumptions on industry standards such as P2/6, the LTDS and RRP data. We also note in Schedule 6 the assumption used by SP concerning total generation growth. As these sources change, it is expected that the methodology would be updated to reflect these changes. Therefore risks in this area may be limited under the proposal. It is also desirable that a methodology attempts to account for expected future developments by adopting a forward looking approach. We have requested views in Annex 2 on the extent to which the methodology is forward looking.

3.22 We welcome views on whether we have adequately captured the risks associated with this modification proposal.

Schedule 1 – Generation test size generator (TSG)

The TSG is the driver of costs in SP's proposed generation charging methodology. We have analysed the sensitivity of EHV generation charges to the size of the TSG. We have considered a sample of network groups at the 33kV voltage level for the SPD network and analysed the impact on network group charges (£/kVA) once compounding 5% increments and decrements are applied to the size of the TSGs. For the purposes of the analysis, we have assumed that the reinforcement solution cost to accommodate the TSG remains constant as the size of the TSG is varied[36].

Figure A.1 below shows the impact of compounding 5% decrements to the size of TSG. The key point to note is that as the size of the TSG *falls* the network group charge *rises*.

Figure A.1: *Five percent decrements in size of TSG on sample SPD network*

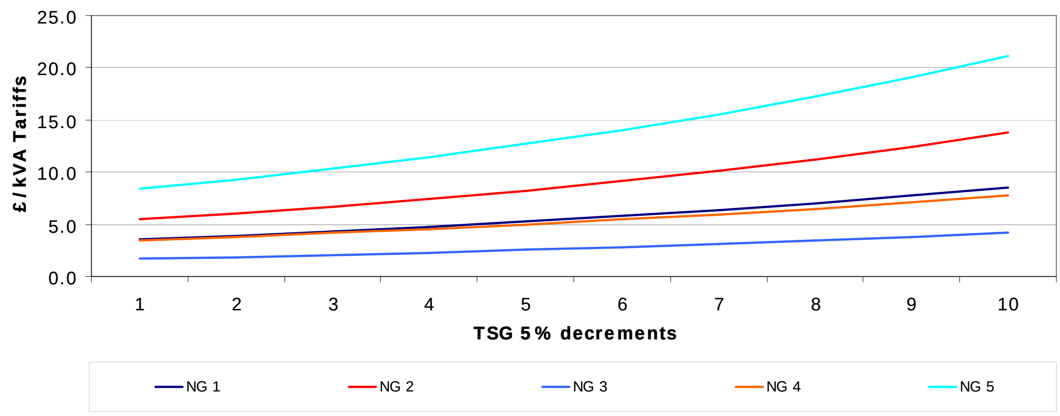
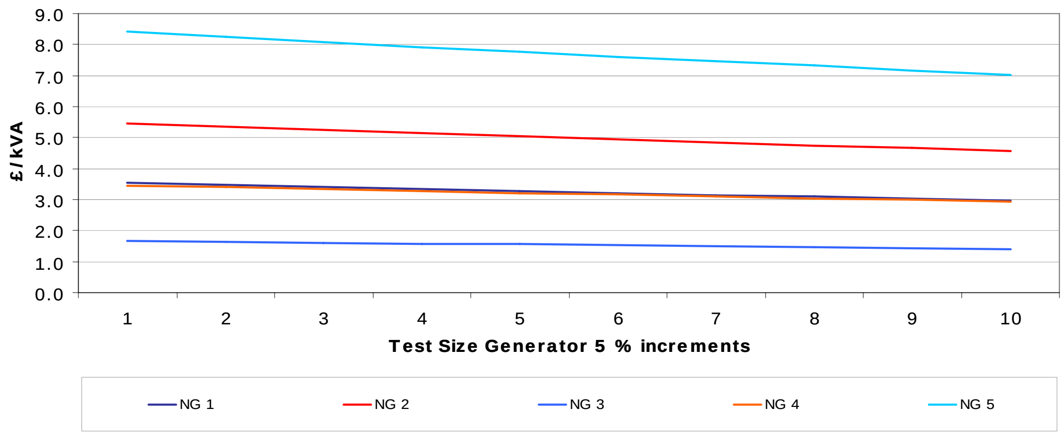


Figure A.2 below shows the impact of compounding 5% increments in the size of the TSG. The key point to note is that as the size of the TSG *rises* the network group charge *falls*.

Figure A.2 *Five percent increments in size of TSG on sample SPD network*



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[36] This is a simplifying assumption. Reinforcement costs in SP's methodology are based on typical costs incurred to accommodate the TSG at a given network group level. Reinforcement costs might therefore be expected to vary as the size of the TSG changes. However, we might also expect this variation to be minimal given the lumpy nature of required reinforcement to accommodate additional generation once network group headroom has been breached.

The analysis above shows an inverse relationship between the size of the TSG and the network group £/kVA generation charge. The analysis appears counter intuitive: as the size of the TSG increases, the years to reinforcement (Y) will fall as a larger generation increment is connected to the network group over a 10 year period.

The discounted expected reinforcement cost at a given network group will therefore be expected to increase and to result in a corresponding *increase* in £/kVA generation charges for a given network group - i.e. we would expect a *proportionate* relationship between TSG and £/kVA charges.[37]

The observed inverse relationship is driven by a number of different elements of the final charging formula (see schedule 6) relating in different ways to changes in the size of the TSG. As the size of the TSG increases:

- The probability (Pv) that the TSG connects across a given voltage level will *fall* reducing expected reinforcement costs;

- The years to reinforcement (Y) will *fall* but *increase* the discounted expected reinforcement cost; and

- Total network group generation over the 10-year period (the denominator from the final charging formula) increases also causing the charge to fall as reinforcement costs are spread across a larger network group generation base.

The points to note from this analysis are as follows:

- Averaging of discounted expected reinforcement costs dilutes the expected impact of changes to the TSG on the years to reinforcement and contributes to the counter intuitive results observed for charges.

- The probability (Pv) that the TSG connects, based on a different generation growth rate to that used to calculate years to reinforcement, is shown to distort the expected charging relationship between the TSG increment and £/KVA charge.

In summary, the use of a TSG increment, in combination with a probabilistic approach to derive expected reinforcement costs, derives a counter intuitive result that *greater* generation growth on the network drives *lower* generation network charges.

[37] As discussed above, this assumes that the reinforcement solution cost to accommodate the TSG remains constant as the size of the TSG varies.

Schedule 2 – Analysis of different size demand and generation increments

Generation

We have developed a worked example of SP's generation charging methodology based on a hypothetical network group. The worked example assumes:

- Fault level driven reinforcement costs;
- Reinforcement costs to accommodate the test size generator (TSG) remains constant as the size of the TSG changes;
- A fault level headroom (MVA) for the 132kV network group;
- A fault level reinforcement solution for a TSG connection at 132kV voltage level; and
- Increasing quantities of small scale generation connect to the distribution network *reducing* the size of the TSG[38].

The inputs and assumptions for the worked example are summarised in Tables A1 and A2 below. These are used to calculate the network group charge by applying SP's charging formula as follows:[39]

A * Pv exp(-iY) / (10(G+Sv/2)

***Table A1**: Inputs to produce worked example of SP generation charging methodology*

Variable	Formula	Charging function	Value
Asset	C1		132kV Outdoor CB Bay
Cost of asset	C2		£850
Assets required	C3		10
Cost of capital	C4	i	6.9%
Initial generation	C5	G	170 MVA
Base year	C6		2008
Headroom	C7	H	38 MVA
Total reinforcement cost	C8 = C2*C3	A	£8,500

Source: Ofgem

To determine the probabilities (Pv) of the TSG connecting to the network group, we have made assumptions for total DG expected to connect to distribution networks over the next 10 years, total demand on the distribution networks and demand requirements at each voltage level of the networks.

[38] The worked example considers eight scenarios for the TSG.
[39] Where A is the total cost of the reinforcement, Pv is the probability of the TSG connecting, i is the discount rate, Y is the years to reinforcement, G is the level of existing generation for the network group and Sv is the size of the TSG.

Table A2: Generation probabilities

Generation Probabilities	Value
10 year growth as % of demand	30%
Total MVA	3500
New Generation	1050

	Voltage	Existing MVA	New MVA	Network Groups	Test Size	Test (MW)	Pv
Scenario 1	132kV	817	599.3	15	71.5	1072.5	0.6
Scenario 2	132kV	817	599.3	15	69.5	1042.5	0.6
Scenario 3	132kV	817	599.3	15	60.0	900.0	0.7
Scenario 4	132kV	817	599.3	15	59.4	890.6	0.7
Scenario 5	132kV	817	599.3	15	56.6	849.4	0.7
Scenario 6	132kV	817	599.3	15	47.8	716.3	0.8
Scenario 7	132kV	817	599.3	15	34.5	517.5	1.2
Scenario 8	132kV	817	599.3	15	21.0	315.0	1.9

Source: Ofgem

The results from applying SP's generation methodology to this hypothetical network group are shown in Table A3 below. The table shows the years to reinforcement and the final £/kVA charge given the TSG assumption for each of the eight scenarios. We have also summarised the years to reinforcement under each scenario in Figure A3.

Table A3: *Results from TSG Scenarios*

	TSG assumption	Years to reinforcement	Year of reinforcement	£/kVA
Scenario 1	71.5	5.3	2013	1.60
Scenario 2	69.5	5.4	2013	1.64
Scenario 3	60.0	6.3	2014	1.83
Scenario 4	59.4	6.4	2014	1.84
Scenario 5	56.6	6.7	2014	1.91
Scenario 6	47.8	7.9	2015	2.12
Scenario 7	34.5	11.0	2018	0.00
Scenario 8	21.0	18.0	2026	0.00

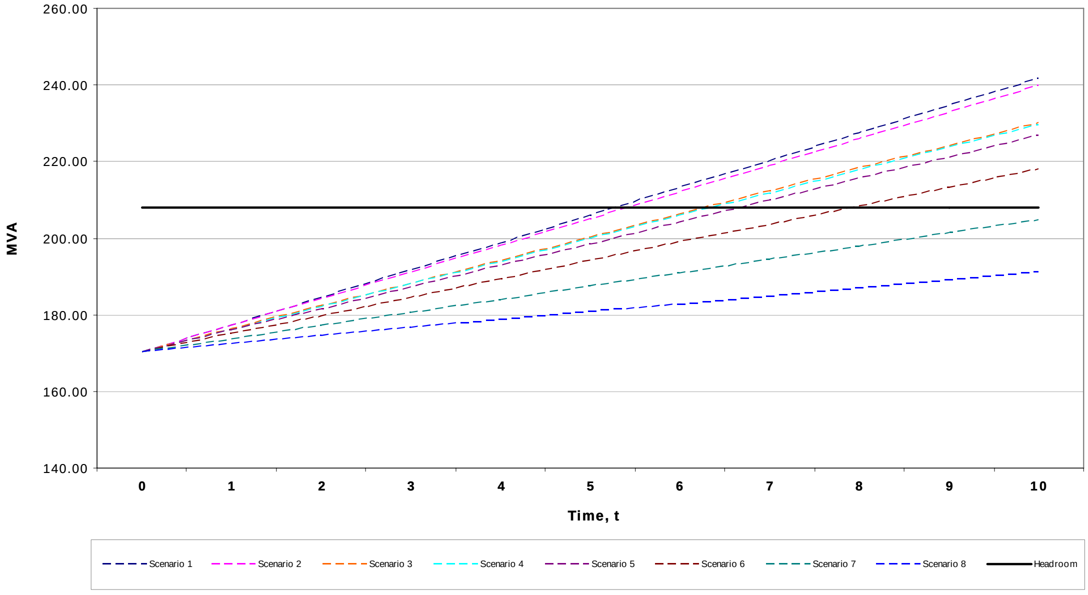
Source: Ofgem

The key points to note from the worked example are as follows:

- We observe a counter intuitive inverse relationship between £/kVA charges and the TSG increment as increasing quantities of small distributed generation connects to the system. This is partly based on the assumption that reinforcement costs to accommodate the TSG remain constant as the size of the TSG changes for each scenario.

- As increasing quantities of small distributed generation connect to the network, the years to reinforcement move out of the 10 year period and cause network charges to fall to zero.

Figure A.3*: Years to reinforcement under TSG scenarios*

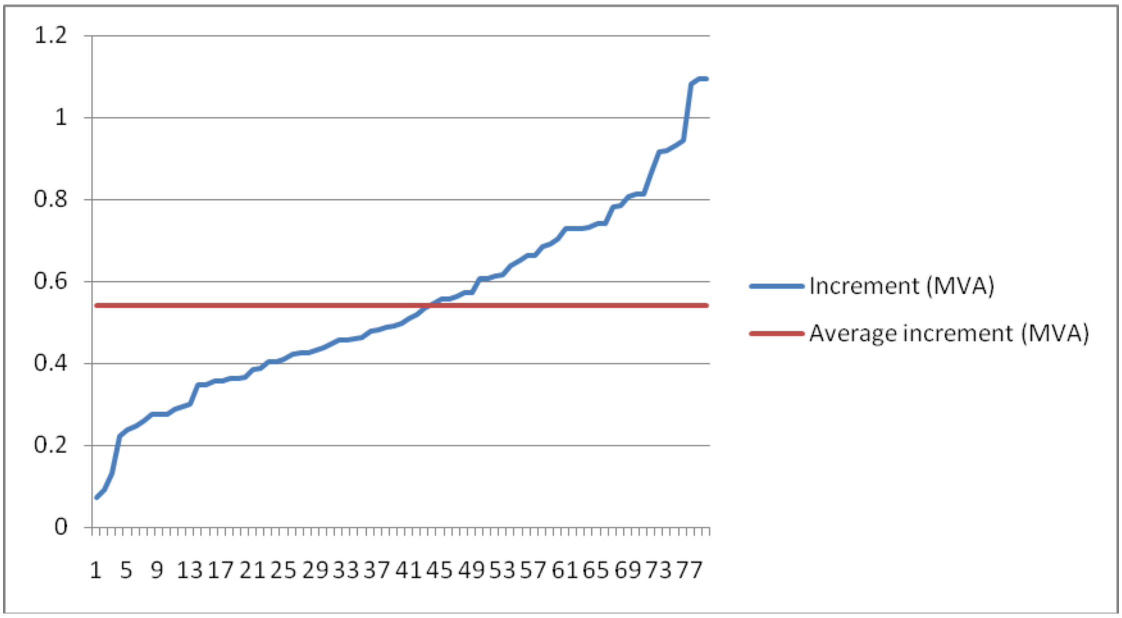


Demand

SP's proposed Demand model uses increments of 1% of the total current capacity in each network group. This results in different increments being used for each network group. Annex 2 asks for views on the extent to which this approach is appropriate.

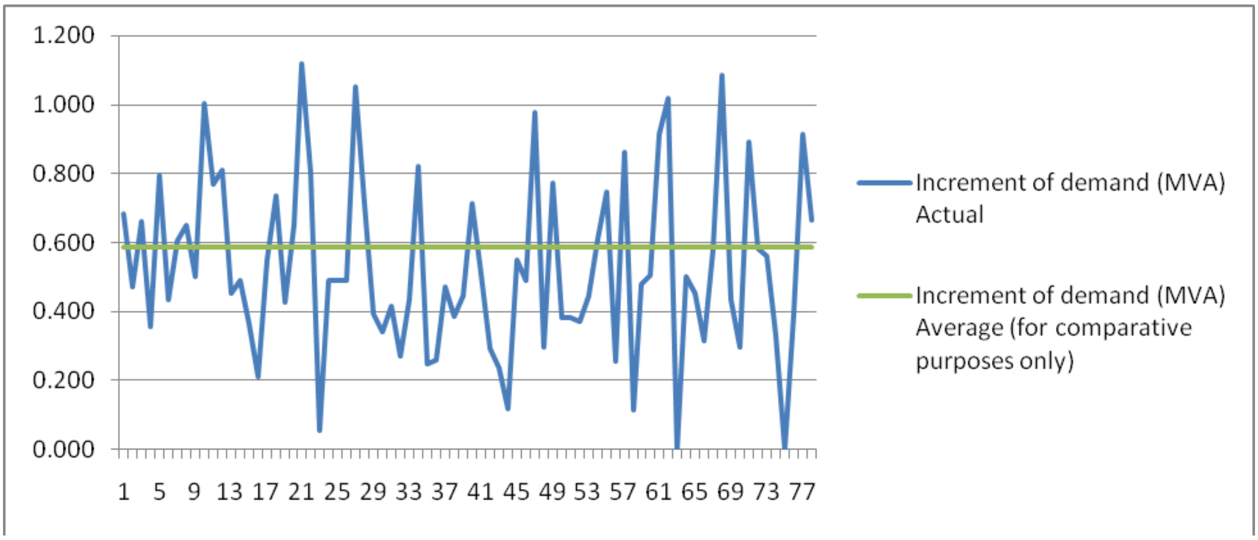
Our analysis has shown that the actual increment used in terms of MVA can very dramatically between network groups as figures A.4 and A.5 demonstrate[40];

Figure A.4



[40] Figure A.4 illustrates the increment used for a network groups (network groups are shown along the x axis). The order was set at random. The average line is merely to illustrate the extent of variation between network groups.

Figure A.5



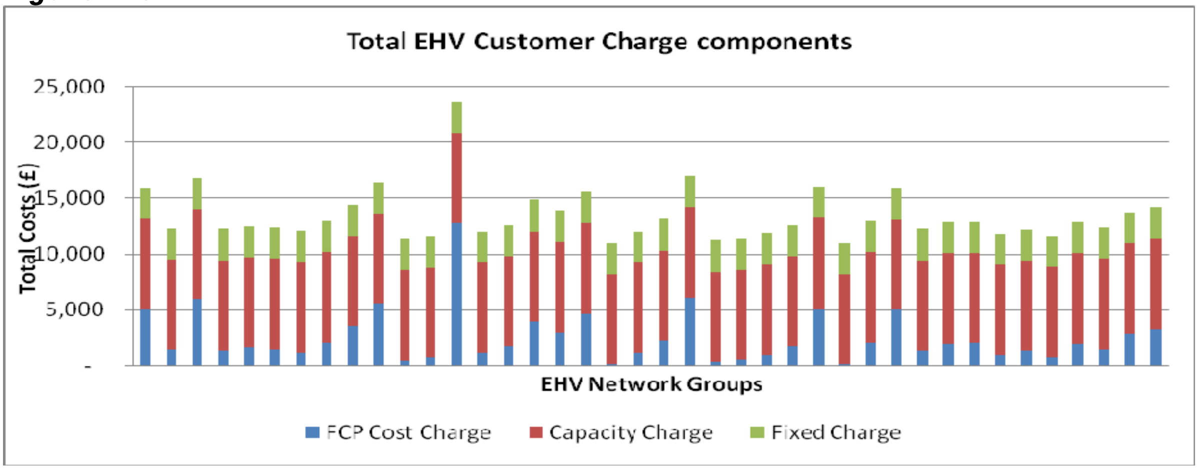
Both figures A.4 and A.5 show the same data. Figure A.4 merely has the network groups placed in size order along the x axis, whilst Figure A.5 has the network groups placed at random along the x axis. Both graphs demonstrate the fact that the increment used at each network group is different and can vary considerably between network groups.

The second point we wish to make on increment, is that SP's model identifies the percentage increment of total network group demand at which an asset will break. As the increment used is 1%, the model can only identify that an asset will break at, say, 7% of network group demand. If we imagine that this 7% represents 47MVA. In reality, the asset could have broken at anywhere between 6.01% (46.56MVA) or 6.99% (46.99MVA). The model does not recognise this due to the 1% granularity used. A model which used a smaller increment would be able to greater reflect the capacity at which the asset broke and reflect this in charges.

Schedule 3 – Scaling analysis

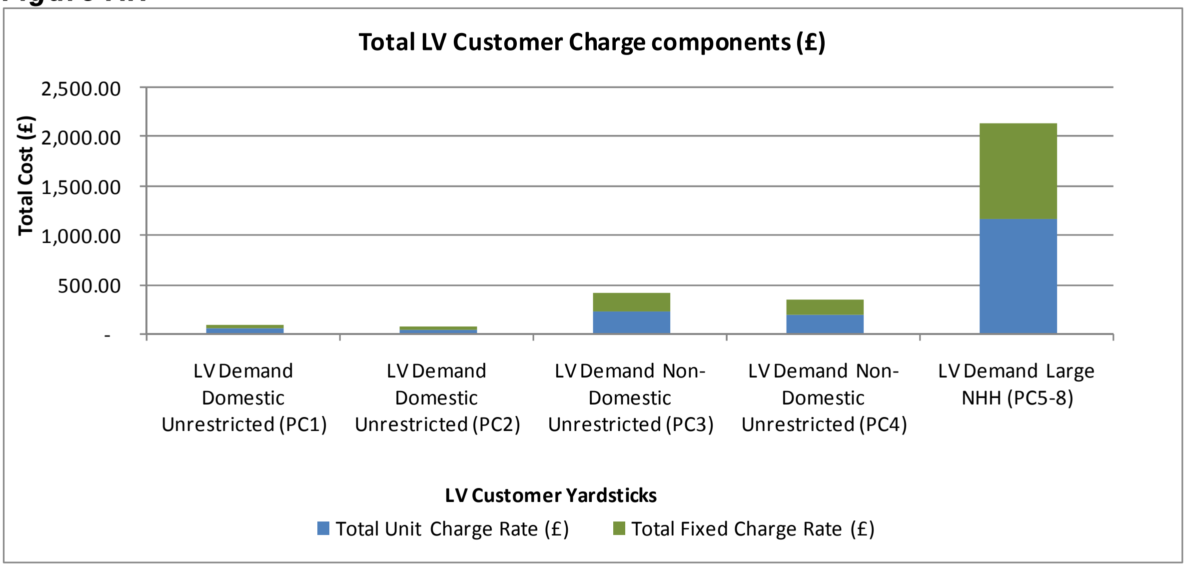
Figure A.6 below shows how the EHV total charge is made up of the various cost components (excluding sole use assets). This chart includes only those network groups with a charge rate greater than £0.00. A customer capacity of 1MW has been assumed for all network groups, so the only variable is the single FCP charge rate. This graph illustrates how the same fixed cost adder is used for all network groups within a customer yardstick.

Figure A.6



LV voltage level tariff charges have only fixed and unit charges. Figure A.7 below shows the total LV charge components per customer yardstick. The graph illustrates that fixed charges vary between customer yardsticks within a given voltage level. The reason for this difference arises from the fact that total costs for each customer yardstick are uniquely divided into fixed and unit costs. The actual percentage contribution of fixed cost to the total cost is determined by the cost allocation model.

Figure A.7



Schedule 4 – Further tariff analysis -Table A.4 (SPM)

No.	Tariff Description	LLFC	Market	PC	Fixed Charges	Unit Charges		Capacity/ Demand Charges	Reactive Power Charges
					Fixed Charge 1 (p/MPAN/day)	Day Unit Charge 1 (p/kWh)	Night Unit Charge 1 (p/kWh)	Capacity Charge 1 (p/kVA/day)	Reactive Power Charge 1 (p/kVArh)
T01	Domestic Unrestricted	101, 102	NHH - import	1	124.79%	-20.13%			
T02	Domestic Heating	111, 131,	NHH - import	2	120.86%	-11.59%	-77.78%		
T03	Domestic Control	104, 106,	NHH - import	2&4		-77.78%			
T04	Metered Cyclocontrol	155	NHH - import	2	120.86%	39.68%			
T05	Off Peak A	135, 140,	NHH - import	2&4		31.30%			
T06	Off Peak C	136, 141,	NHH - import	2&4		95.97%			
T07	Off Peak D	137, 142,	NHH - import	2&4		39.68%			
T08	Business Single Rate, LVN & LVS	201, 202,	NHH - import	3	274.85%	-15.49%			
T09	Business Two Rate, LVN & LVS	205, 231,	NHH - import	4	257.21%	-26.11%	-64.86%		
T10	Business Peak, LVN & LVS	203, 209	NHH - import	3	274.85%	-15.49%	-15.49%		
T11	Business Control, Credit, LVN	212	NHH - import	4		-64.86%			
T12	Business MD, LVN	401, 402	NHH LVN - import	5-8	267.86%	-22.40%	-54.17%		
T13	Business MD, LVS	403, 404	NHH LVS - import	5-8	218.78%	-40.63%	-61.90%		
T14	Business MD, HVN	405	NHH HV - import	5-8	-69.65%	-63.86%	-100.00%	-100.00%	0.00%
M16	Business HH, LVN	501	HH LVN - import	0	-69.36%	-15.89%	-57.89%	-100.00%	0.00%
M17	Business HH, LVS	503	HH LVS - import	0	-54.92%	-39.81%	-66.67%	-100.00%	0.00%
M26	Business HH, LVN	511	HH LVN - import	0	-69.36%	-15.89%	-57.89%	117.52%	0.00%
M27	Business HH, LVS	513	HH LVS - import	0	-54.92%	-39.81%	-66.67%	280.65%	0.00%
M36	Business HH, LVN Generator import	591	HH LVN - import	0	-69.36%	-15.89%	-57.89%	117.52%	0.00%
M37	Business HH, LVS Generator import	592	HH LVS - import	0	-54.92%	-39.81%	-66.67%	280.65%	0.00%
M18	Business HH, HVN	505	HH HVN - import	0	-97.80%	-53.01%	200.00%	84.38%	0.00%
M19	Business HH, HVS	507	HH HVS - import	0	-55.65%	-64.52%	144.44%	-100.00%	0.00%
M28	Business HH, HVN	515	HH HVN - import	0	-97.80%	-53.01%	200.00%	121.88%	0.00%
M29	Business HH, HVS	517	HH HVS - import	0	-55.65%	-64.52%	144.44%	262.50%	0.00%
M38	Business HH, HVN Generator import	593	HH HVN - import	0	-97.80%	-53.01%	200.00%	121.88%	0.00%
M39	Business HH, HVS Generator import	594	HH HVS - import	0	-55.65%	-64.52%	144.44%	262.50%	0.00%
T15	UMS, good inventory	900, 901,	NHH - UMS	1&8	-100.00%	-4.79%			
T16	UMS, poor inventory	904, 905,	NHH - UMS	1&8	-100.00%	-17.19%			
	132kV connected	801+	HH EHV - import	0	-90.09%			-100.00%	0.00%
	33kV connected	801+	HH EHV - import	0	-88.82%			-100.00%	0.00%
	LV connected generators with non-half-hourly metering		NHH - export	1-8					
E01	LVN connected generators pre April 05	795	HH LVN - export	0					0.00%
E02	LVS connected generators pre April 05	796	HH LVS - export	0					0.00%
E05	LVN connected generators post April 05	791	HH LVN - export	0					0.00%
E06	LVS connected generators post April 05	792	HH LVS - export	0					0.00%
E03	HVN connected generators pre April 05	797	HH HVN - export	0					0.00%
E04	HVS connected generators pre April 05	798	HH HVS - export	0					0.00%
E07	HVN connected generators post April 05	793	HH HVN - export	0				0.00%	0.00%
E08	HVS connected generators post April 05	794	HH HVS - export	0				0.00%	0.00%
	EHV connected generators ANGLESEY	601+	HH EHV - export	0				-100.00%	-100.00%
	EHV connected generators NORTH WALES EXCLUDING A	601+	HH EHV - export	0				-100.00%	-100.00%
	EHV connected generators MID WALES	601+	HH EHV - export	0				-100.00%	-100.00%
	EHV connected generators MERSEYSIDE, CHESHIRE ETC	601+	HH EHV - export	0				-100.00%	-100.00%

Table A.5 (SPD)

No.	Tariff Description	LLFC	Market	PC	Fixed Charges	Unit Charges			Capacity/ Demand Charges	Reactive Power Charges
					Fixed Charge 1 (p/MPAN/day)	Day Unit Charge 1 (p/kWh)	Day Unit Charge 2 (p/kWh)	Night Unit Charge 1 (p/kWh)	Capacity Charge 1 (p/kVA/day)	Reactive Power Charge 1 (p/kVArh)
T01	Domestic Unrestricted	100, 101,	NHH - import	1	90.37%	-21.95%				
T02	Domestic Heating	110, 111,	NHH - import	1	0.78%	-7.53%				
T03	Heating	112, 113,	NHH - import	2				-89.29%		
T04	Domestic Day/night	114, 115,	NHH - import	2	0.78%	-7.53%		-89.29%		
T05	HWR Domestic Heating	160, 161		1	101.56%	-7.53%				
T06	12hr Off Peak	132, 241, 133	NHH - import	2				-9.00%		
T07	16/20hr Off Peak	134, 242, 135	NHH - import	2				-24.79%		
T08	Storage Boiler	136	NHH - import	2				-28.91%		
T09	12hr Crop & Air Conditioning	243	NHH - import	3		-8.70%				
T10	16hr Crop & Air Conditioning	244	NHH - import	3		-24.55%				
T11	Crop Conditioning	245	NHH - import	3		-8.70%	-100.00%			
T12	Catering	246	NHH - import	3		-30.83%				
T13	12hr Off Peak HV	301	NHH - import	4				-98.15%		
T14	Business Single rate	200, 201,	NHH - import	3	121.32%	-30.90%				
T15	Business Evening & Weekend	220, 221,	NHH - import	3&4	52.02%	-45.70%		-95.40%		
T16	Business Heating	223, 225	NHH - import	4				-95.40%		
T17	NHH MMD LV <100kW (PC5-8)	400, 402	NHH LV & HV - import	5-8	-49.90%	-44.85%		276.92%		
T18	NHH MMD HV<100kW (PC5-8)	401, 403	NHH LV & HV - import	5-8	-100.00%	-68.42%			-100.00%	
M03	HH LV	500	HH LV - import	0	506.53%	-17.69%		-62.50%	-100.00%	-2.91%
M07	Embedded Generation Import LV	504	HH LV - import		564.74%	-17.69%		-62.50%	139.36%	-2.91%
M04	HH HV	501	HH HV - import	0	-97.68%	-52.63%		-100.00%	304.90%	-5.88%
M08	Embedded Generation Import HV	505			-97.68%	-52.63%		-100.00%	304.90%	-5.88%
T19	UMS Good Inventory	900, 901,	NHH - UMS	8&1	140.23%	-53.33%				
T20	UMS Poor Inventory	904, 905,	NHH - UMS	8	140.23%	-57.58%				
T21	UMS Public Lighting Good Inventory	908	NHH - UMS	1&8	-100.00%	-20.51%				
T22	UMS Public Lighting Poor Inventory	909	NHH - UMS	1&8	-100.00%	-27.74%				
	33kV Connected	801+	HH EHV - import	0	-100.00%					1825.00%
E06	LV Connected Generators with NHH metering		NHH - export	1-8						
E07	LV Connected Generators pre April 2005	604	HH LV - export	0						
E05	LV Connected Generators post April 2005	607		0						-100.00%
E08	HV Connected Generators pre April 2005	605	HH HV Export	0						
E04	HV Connected Generators post April 2005	606		0						-100.00%
E01	EHV Connected Generators Borders	601+	HH EHV - export	0					-100.00%	-100.00%
E02	EHV Connected Generators SouthWest	601+								
E03	EHV Connected Generators Central	601+								

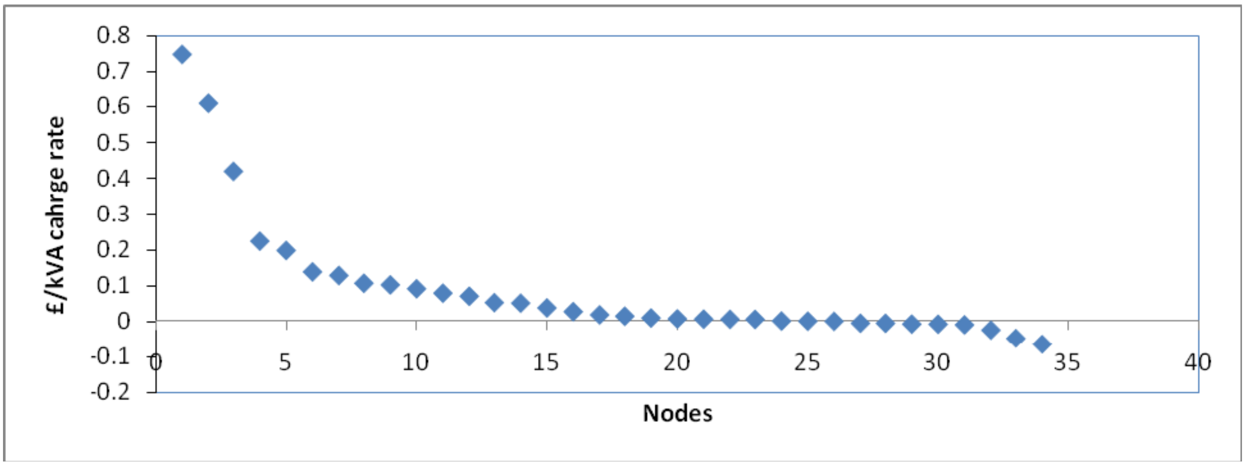
Schedule 5 – Network group aggregation

As discussed in Annex 2, SP propose to produce a specific charge rate for each time period across a whole network group. SP define a Network group as "part of the distribution system that, under normal system conditions, is not connected electrically to adjacent Network Groups at the same voltage level".

SP's power flow model shows where assets within the network group will break at different increments of current total demand. These costs are then allocated into a charge rate which is applied across the network group. In Annex 2 we ask whether it is appropriate to smear the cost of reinforcement across a network group and if all customers connected within that network group will have contributed equally to the need to reinforce that asset.

Other DNOs have chosen to charge at a nodal rather than network group level. The graph below shows the full range of costs of marginal costs at different nodes within a network group of another DNO. SP's proposal would not be able to take account of these variations as it adds the cost of reinforcing all network group assets together. Consequently, no signal is provided of the high marginal cost of some nodes (top left of Figure A.8) as these are aggregated within a network group.

Figure A.8[41]



[41] Figure A.8 illustrates the different nodal marginal costs which exist within a network group for another DNO.

Schedule 6 – Detailed explanation of EHV/HV FCP generation model

Discussion of the generation model is divided into five steps.

Step 1 – Reinforcement costs incurred by installation of TSG

In Step 1, the FCP generation model calculates the reinforcement costs that will be incurred by the installation of a standard test size generator (TSG).

The TSG is chosen to be the 85th percentile of existing connected and planned generator sizes for each voltage level. Table A6 below shows the TSG sizes that SP currently proposes to use for its respective networks.

Table A6: Test size generator

Voltage Level	SPM	SPD
132kV	136.1	N / A
33kV	36.1	32.2
HV	5.0	8.2
LV	0.7	1.5

Source: Scottish Power Energy Networks

For each EHV network group[42] (network sub-group at HV) power flow analysis is used to assess the fault level and reverse power flow headroom (H) which can be accommodated by the network before reinforcement would be required.

Where the TSG exceeds the headroom (TSG > H) reinforcement costs incurred by the installation of the TSG are allocated to the FCP rate. Where the TSG is less than the headroom (TSG < H), then the FCP rate is set to zero.

Step 2 – Expected reinforcement costs over 10 year horizon

In Step 2, the generation cost model scales the reinforcement costs from a TSG connection by the probability (Pv) of such generation actually connecting to a given network group. This gives a measure of the *expected* reinforcement costs for the network group (sub-group) incurred by generation over the next ten years.

The probability (Pv) of a TSG attaching to a network group is calculated by matching the total capacity of a TSG connecting to each network group at a given voltage level, against the forecast generation growth for that given voltage level. The forecast generation growth for a given voltage level is derived by assuming total new generation capacity over the next 10 years will be 30% of current demand, and is applied to all the network groups within that voltage level.[43]

Step 3 – Forecasting expected total EHV / HV generation over 10 year horizon

In Step 3, the generation model calculates the years when generation induced reinforcement will be required (Y) and forecasts total EHV generation over the ten year period given the connection of a TSG.

The years to reinforcement is calculated based on an assumed EHV generation growth path based on the size of the TSG and the probability of the TSG connection. By assuming there is an equal probability of the TSG connecting in each of the ten years (with the probability of connection rising from zero at time zero, to the test size at the end of the ten years) the generation model derives a linear generation growth rate for the ten year period. Given this growth rate and the

[42] The EHV network is split between 132kV and 33kV.
[43] Forecast generation growth is based on DTI/Ofgem forecasts for Great Britain DG capacity and National Grid electricity demand projections.

fault level and reverse power flow headroom (H) derived from power flow analysis in Stage 1, the number of years until reinforcement (Y) is derived.

Step 4 – Derive final £/kVA EHV / HV generation costs

In Step 4, £/kVA generation charges are calculated by spreading the discounted total reinforcement costs across total expected EHV generation for the 10 year period. The generation FCP rate is set to: [44]

$$A * Pv \exp(-iY) / (10(G+Sv/2)$$

The key points to note from the EHV / HV generation cost model and its final charges are as follows:

- EHV generation charges are calculated by spreading total generation induced reinforcement costs across total EHV generation over the 10 year period. This approach allows reinforcement costs to be recovered in total and, all things being equal, we believe charges would be the same over the 10 year period. Charges are set equal to costs averaged across total generation over the 10 year period.
- Generation charges are driven by fault level and reverse power flow induced costs (rather than thermal capacity) and these reinforcement costs are recovered in total from the final £/kVA per annum charge. A probabilistic approach is used to derive total expected generation induced reinforcement costs and the years when generation induced reinforcements will be required.

Step 5 – Derive EHV / HV / LV generation net benefit

In Step 5, the benefit that additional generation brings to the network – in terms of the reduced requirement for network reinforcement due to offset demand - is calculated.

Generation benefits are set equal to the demand costs (for the voltage of connection as well as the voltages above the point of connection) scaled by the P2/6 generation contribution factor (F-Factor) at the voltage of connection. Generation benefits are therefore cumulative from the point of connection up to the highest network voltage level.

For the EHV and HV levels, the generation benefits are added to generation costs to derive net generation costs for final DUoS charges.

For the LV voltage level, generation costs are assumed to be zero and so only benefits are recognised for final DUoS charges.

Generation Vs Demand

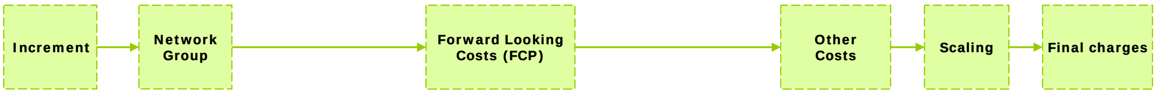
In order to analyse the effects of the proposed differences between demand and generation FCP models we have defined a scenario for a similar sized demand and generation connection.

The scenario involves a new 10 MW load and a new 10 MW generation customer wishing to connect to a given network group. The scenario then aims to consider whether consistent price signals – allowing for probable differences in costs - are provided to both the new demand and the new generation customers.

Figure A.9 below summarises the process that is used to derive a hypothetical 10MW demand customer's final charge.

Figure A.9

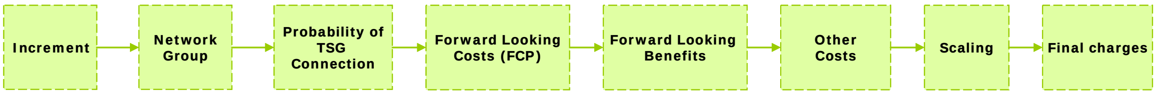
[44] Where A is the total cost of the asset reinforcement, Sv is the size of the TSG, i is the discount rate and G is the level of existing generation for a given network group.



The 10 MW demand customer's final charges will reflect the discounted reinforcement cost from the forecast incremental demand growth at the given network group (the FCP marginal cost reflecting in a unit charge) and other costs related to O&M / refurbishment / customer services (reflected in a final fixed charge).

Figure A.10 below summarises the process that is used to derive a hypothetical 10MW generation customer's final charge.

Figure A.10



The 10 MW generation customer's final charges will reflect the *expected* discounted reinforcement cost from a TSG connection at the given the network group (the FCP marginal cost), the benefit that generation confers on the network at each voltage level (set equal to demand costs scaled by P2/6 F-Factors) and other costs that are reflected in a final fixed charge.

Schedule 7 – Consultation Questions

i) The use of Network group aggregation and different increments

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

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

3. ***The appropriateness of the charge pricing function.***

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

4. ***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***.

5. ***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 distributed generation which is likely to flatten any 'lumpy' connection of generation.***

iii) Varying the size of the test size generator

6. ***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.***

7. ***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.***

iv) Use of historic RRP data in HV/LV charging

8. ***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.***

9. ***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.***

v) Time banding

10. ***We welcome views on SP's use of time bands and whether it is appropriate to have time bands reflected for LV/HV charges but not at EHV.***

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

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

13. ***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?

14. ***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?***

15. ***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.***

vi) *Recognition of intermittent generation*

16. **We welcome views on the extent to which SP are correct in using F factors to calculate the benefit LV generation can provide to the network.**

vii) Reactive power charging

17. **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.**