METHODOLOGY STATEMENT DETAILING THE BASIS OF SP MANWEB PLC'S USE OF SYSTEM CHARGES APPLICABLE FROM 1 APRIL 2009

This statement has been approved by the Gas and Electricity Markets Authority (GEMA)

SP Energy Networks
New Alderston House
Dove Wynd
Strathclyde Business Park
Bellshill
ML4 3FF

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1 Introduction

1.1 This statement describes the Use of System Charging Methodology under which authorised users will be charged for use of SP Manweb's electricity distribution system.

1.2 Words and expressions used in this statement have (unless specifically defined herein) the definitions given to them in the Electricity Act 1989, as amended ('the Act') or SP Manweb's Distribution Licence ('the Licence') and shall be construed accordingly.

1.3 This statement has been approved by the Gas and Electricity Markets Authority (the Authority). Copies of this statement can be obtained free of charge via our website; http://www.scottishpower.com/ConnectionsUseMetering.htm.

Who we are

1.4 SP Manweb Plc is the licensed electricity distribution business which owns and operates networks in Merseyside, Cheshire and North Wales. ScottishPower EnergyNetworks (SPEN) is the public facing identity of SP Distribution Ltd (SPD), SP Manweb Plc (SPM) and SP Transmission Ltd (SPT).

Licence Obligations

1.5 This statement describes the Use of System Charging Methodology under which authorised persons will be charged for use of SPM's electricity Distribution System. The methodology applies to charges that become effective on or after 1 of April 2009.

1.6 SPM is obliged, under Licence Condition 4, paragraph 1(a), of its Electricity Distribution Licence, to prepare a statement approved by the Authority setting out the methodology upon which charges will be made for the provision of Use of System. We are also obliged to review our Use of System Charging Methodology annually in accordance with Licence Condition 4, paragraph 2(a) and in order to comply with paragraph 2(b) make such modifications to the Use of System Charging Methodology that better achieve the Relevant Objectives.

1.7 "…the Relevant Objectives are:

a) 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 this Licence;

b) 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;

c) 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

d) that, so far as is consistent with sub-paragraphs a), b) and c), the Use of System Charging Methodology, as far as is reasonably practicable, properly takes account of developments in the licensee's distribution business."

1.8 Words and expressions used in this statement have (unless specifically defined herein) the definitions given to them in the Act or the Licence and shall be construed accordingly.

Price Control

1.9 SPM is a licensed distribution business and is regulated by the Gas and Electricity Markets Authority through the Office of Gas and Electricity Markets (Ofgem). The regulation is applied via the Distribution Licence and the price control mechanism. The price control period is five years and Ofgem prescribe the amount of revenue that SPM is allowed to recover from its customer base annually and over the price control period. Use of System charges may vary from time to time, with appropriate notice, as SPM sets its Use of System Charges to recover its allowed revenue.

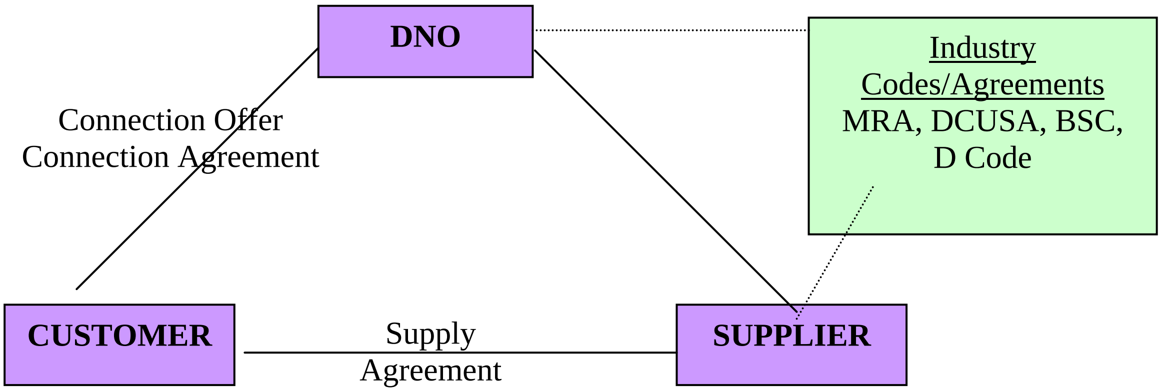
Connection and Use of System Boundary

1.10 SPM splits the recovery of costs between charges for connection to the Distribution System and on-going Use of System Charges for utilisation of the network. The boundary point at which this split occurs is common to both demand and generation customers. This statement details the charging methodology that is applied for the calculation of Use of System Charges. In addition our 'Use of System Charging Statement' details the Use of System Charges that are applied, whilst the 'Connection Charging Methodology' details the methodology used to calculate connection charges. The latter statement also contains indicative charges and examples to aid understanding of connection charges. Copies of these statements can be obtained free of charge via our website; http://www.scottishpower.com/ConnectionsUseMetering.htm. .

The Contractual Framework

1.11 Users entitled to use SP Manweb's electricity distribution system are those who are authorised by Licence or by exemption under the Act to supply, distribute or generate electricity. In order to protect all Users of the system, SP Distribution will require evidence of authorisation before agreeing terms for use of the system. NOTE: In the rest of this commentary, requirements applying to authorised Users or Authorised Electricity Operators should be taken to mean Licensed Suppliers, Licensed Embedded Electricity Distributors or Licensed Generators.

High Level Contractual Framework



1.12 Users seeking to use the system will be required, prior to using the system, to enter into an agreement with SP Distribution setting out the obligations of both parties. The party seeking use of the system will be required to:

- pay all charges due in respect of use of the system as described in this statement and the accompanying schedules;
- be a party (where the person is a Licensed Supplier) to the Master Registration Agreement (MRA) for the provision of metering point administration services within SP Distribution/SP Manweb's authorised area;
- enter into the National Grid Electricity Transmission's (NGET) Connection and Use of System Code and any necessary Bilateral Agreement, governing connections to and use of NGET's transmission system, unless SP Manweb is informed by NGC that this is not required in any particular case;
- be a party to the Distribution Connection and Use of System Code (DCUSA);
- be a party to the Balancing and Settlements Code (BSC); and
- comply with the provisions of the Distribution Code (DC).

If the applicant and SP Manweb fail to agree contractual terms, or any variation of contractual terms proposed by SP Manweb, either party may request settlement by the Office of Gas and Electricity Markets (OFGEM).

1.13 While the terms and conditions in the agreements will be consistent with those in this statement, the agreement will take precedence. Where a User, having entered an agreement for use of SP Distribution's electricity distribution system, ceases for whatever reason to be a User with respect to that use of the system, then the entitlement to use of the system will cease forthwith, but the User will continue to be liable under the agreement unless and until the agreement is terminated. In order to avoid any liability in this regard, a User wishing to terminate his agreement or wishing to notify a change should give SP Manweb no less than 28 days' notice. SP Manweb will normally respond within 28 days of a notification of change.

1.14 Terms and conditions for connection of premises or other electrical systems to SP Manweb's electricity distribution system are contained in the Connections Statement, which is available from SP Manweb on request. Persons seeking use of the system with respect to a new supply, must apply for connection in accordance with the terms and conditions described in that statement.

1.15 Where a person requires a connection to SP Manweb's electricity distribution system pursuant to Section 16 of the Electricity Act (as amended), the provisions of this statement are without prejudice to the provisions of sections 16 to 22 of the Electricity Act (as amended) (those sections which deal with the rights, powers and duties of SP Manweb, as an electricity distributor), in respect of the distribution of electricity to owners or occupiers of premises.

Contact Details

1.16 This statement has been prepared in order to discharge SPM's obligation under Condition 4 of the Licence. If you have any questions about this statement please contact us at the address shown below. Also given below are contact details for the Office of Gas and Electricity Markets should users and prospective users need to enquire separately on matters relating to this statement.

SPM	Ofgem
Pricing Team, Regulation	9 Millbank
SP Energy Networks	London
New Alderston House	SW1P 3GE
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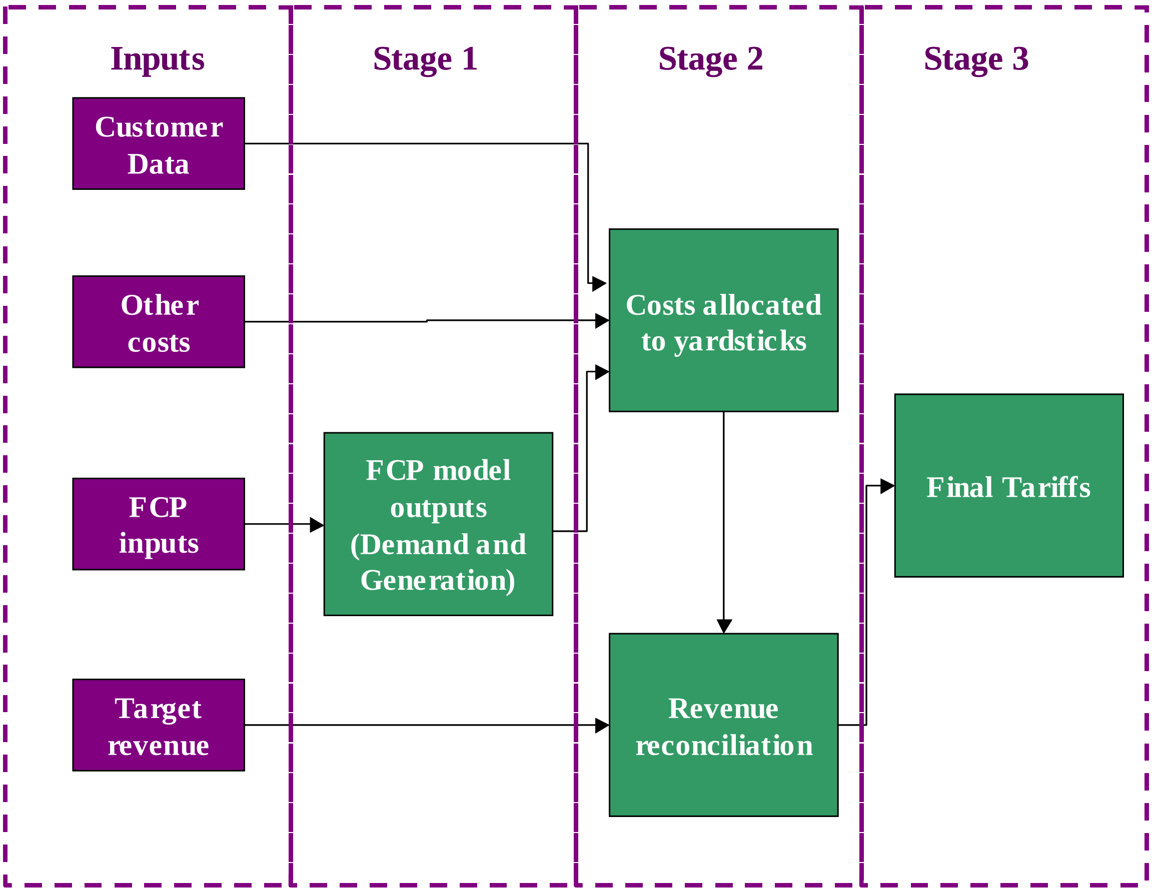
Email: commercial@sppowersystems.com	
Tel: 0151 609 2359	

2 Overview of Methodology

2.1 The Use of System methodology can be described as a three stage process, as set out in the diagram below[1].

Flowchart - High level architecture of methodology



2.2 In the first stage, forward-looking FCP rates (£/kVA/annum) for reinforcement of the network are determined by the Forward Cost Pricing (FCP) methodology. For demand, the FCP methodology forecasts future reinforcement using load flow contingency analysis based on the actual configuration of the network, demand data and growth assumptions for EHV, down to the EHV/HV level of the network. These forecasted reinforcements are then converted into the forward-looking costs for these voltage levels, which provide economic locational signals to current and prospective EHV customers. For the High Voltage (HV) and Low Voltage (LV) levels of the network the FCP methodology uses historic reinforcement data to build a forecast of future

[1] The use of system methodology was developed jointly by ScottishPower EnergyNetworks, Scottish and Southern Energy Power Distribution and Central Networks working together as the G3 group.

reinforcement costs. The EHV proportion of costs which is allocated to HV and LV costs is cascaded from the FCP costs on an averaged basis.

2.3 The FCP methodology for generation identifies both the generation costs and generation benefits. The costs are determined by performing a fault level and reverse power analysis of the real network, down to the 33/11 kV level. Benefits are calculated in relation to the demand costs that generation would offset.

2.4 The second stage is the application of the tariff model. This model brings together the FCP rates and benefits determined by the FCP methodology in the first stage of the process, and all other relevant costs (such as O&M, refurbishment, NGET Connection (Exit) and Licence costs). It then uses other inputs such as demand and volume data to profile these costs and allocate them to the appropriate customer groups, producing yardstick costs. These yardstick costs are then put together with other costs, such as site-specific sole-use asset costs and scaled to match the target revenue.

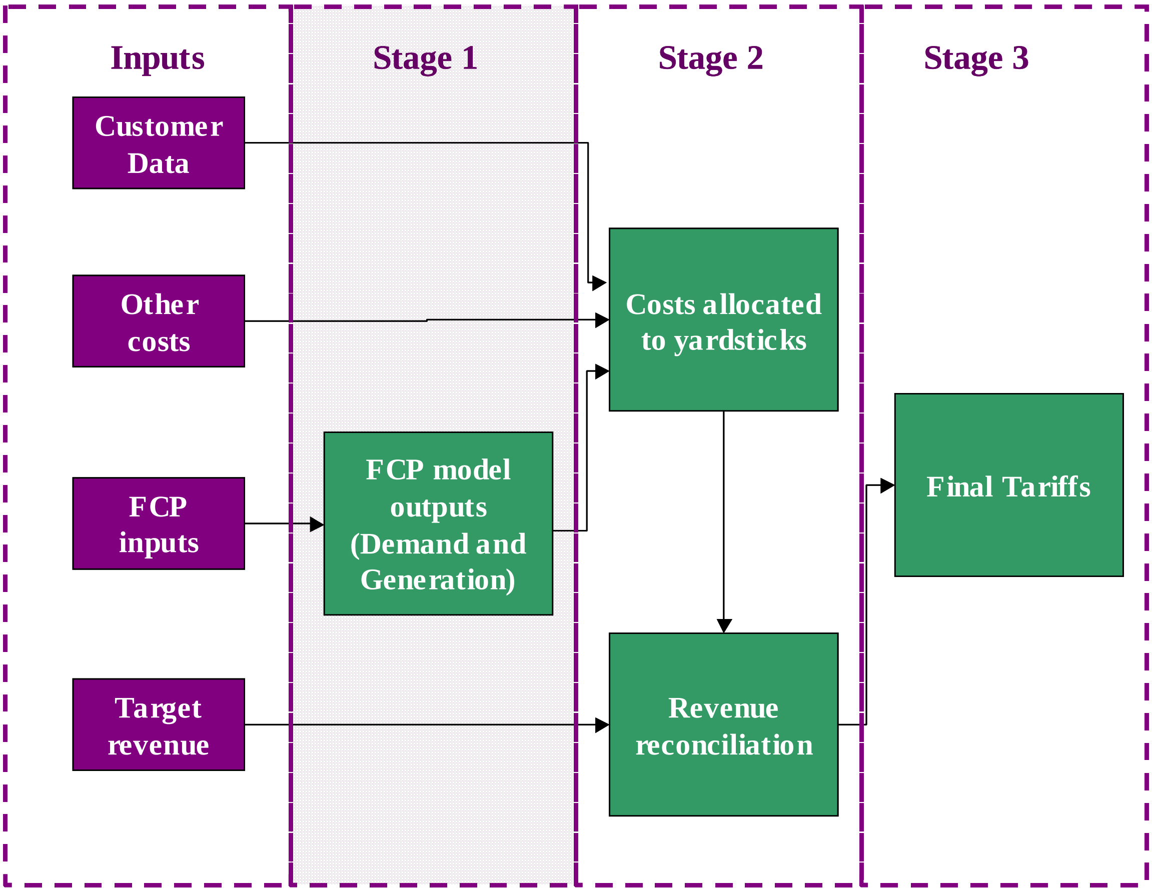
2.5 From the yardstick costs, the final tariffs are produced in the third stage of the process according to a predetermined allocation method.

2.6 Wherever possible the methodology makes use of auditable data such as the Long Term Development Statement (LTDS), regulatory reporting information and other publicly available data, in order to comply with the principle of transparency.

2.7 The following sections explain the methodology in more detail.

3 Forward Cost Pricing (FCP)

STAGE 1: FCP MODEL

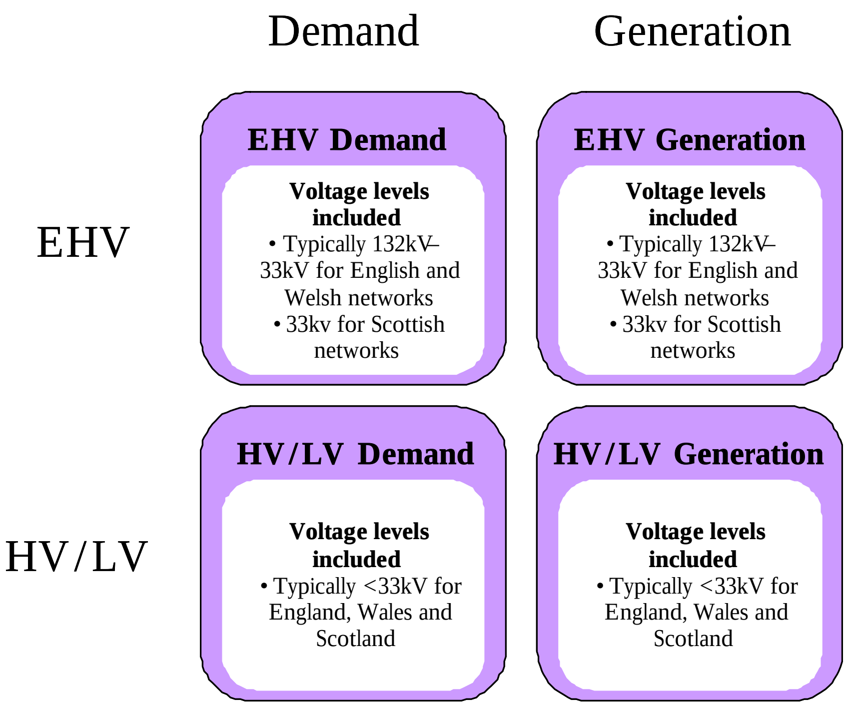


3.1 The FCP approach constitutes the core of the charging methodology: it generates estimates for reinforcement costs over the next 10-years for different Network Groups and then uses these estimates to generate the pre-scaling £/kVA/annum charges that are later converted to final output tariffs in stages 2 and 3.

3.2 The FCP model is a combination of four semi-autonomous sub-models, which separately generate £/kVA/annum estimates for:

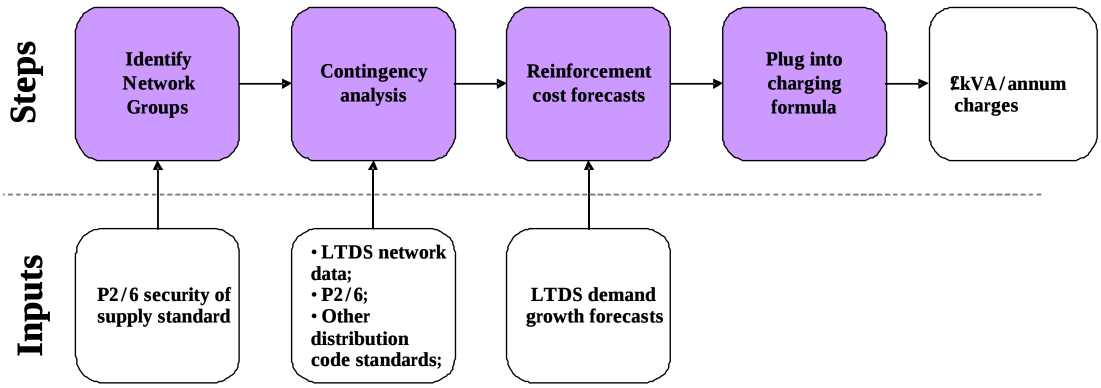
- Demand connected at EHV levels;
- Generation connected at EHV levels;
- Demand connected at the HV and the LV levels; and
- Generation connected at the HV and the LV levels.

3.3 The diagram below illustrates the four sub-models of the FCP:



EHV Demand

3.4 The approach set out below is used for forecasting future reinforcements at the EHV levels (132kV and 33kV). The following diagram illustrates how for EHV demand, the FCP model derives £/kVA/annum charges in four steps:



3.5 For the purpose of forecasting future reinforcement the network is broken down into a number of Network Groups. The use of Network Groups for analysis is an important stage in assessing Security of Supply requirements and is consistent with the security of supply standard, P2/6, which also defines the required network capability in terms of the same 'demand groups'. Each Network Group is a part of the distribution system that, under normal system conditions, is not connected electrically to adjacent Network Groups at the same voltage level.

3.6 A Network Group is the distribution network normally supplied by a Grid Supply Point (GSP), or Bulk Supply Point (BSP). In situations where GSPs or BSPs are operated in parallel, these are considered as a single Network Group. Two layers of Network Groups are considered (GSP to BSP and BSP to 33/11kV substation).

3.7 Within a Network Group, all the circuits, transformers and substations are modelled and individual reinforcements are identified for each asset.

3.8 The method of determining the need for future reinforcement is based on Alternating Current (AC) load flow analysis of each Network Group. This takes into account network security requirements[2] by analysing each Network Group under both normal operating conditions (intact network), and various combinations of network component outage. This 'Contingency Analysis' essentially seeks to identify the weakest links in each Network Group – i.e. to identify which components exceed their capability at various demand levels. Planning processes then identify the reinforcement requirements of these overloaded circuits, transformers and switchgear.

3.9 Analysis is based on mechanistic and deterministic processes using planning information published annually in the LTDS. This information includes network data, demand forecast tables and embedded generation data (the inclusion of embedded generation data is a voluntary additional submission, commonly made by DNOs in the LTDS). The analysis also utilises publicly available planning standards such as ER P2/6.

3.10 The analysis is first carried out using present loading conditions to produce a set of baseline data. For demand, the baseline is assessed using current maximum loading conditions, while for generation the baseline is assessed using current minimum loading conditions. The base network demand is then incremented in small steps, up to a level that is able to encapsulate the expected growth in the network over the nest ten years above their current maxima. At each increment the various contingency analyses are repeated to identify limiting components.

3.11 The contingency analysis identify which network components require reinforcement. Reinforcements are provided by adding suitably sized standard components in a mechanistic way, according to current engineering practice. Reinforcements are sized to remove the limitations as identified and are assumed to have no effect on the need for other reinforcements.

3.12 For the very largest Network Groups, P2/6 also requires contingency analysis under second circuit outage conditions, such as might occur typically during periods of maintenance outage. Contingency analysis assesses network capability under these conditions using the peak maximum demands scaled to 67% and incremented as before.

3.13 Once the network contingency analysis has been performed, the resulting levels of demand at which various network components require reinforcement are used to estimate the length of time when the reinforcement will be needed from the present day, by reference to the relevant network group's demand growth rate. The demand

[2] Network security is a licence condition embodied in Engineering Recommendation P 2/6 (ER P2/6)

growth rates are taken from the LTDS data and are specific to each individual network group.

3.14 All reinforcements found to be required within the time horizon of ten years are included in forward cost estimates. Reinforcements beyond a time horizon of ten years are considered too speculative to be included in realistic forward cost estimates.

3.15 The cost of each standard reinforcement is estimated using the same available design data currently used by the engineers to prepare connection offers, and this is used to derive the FCP rate per kVA for each Network Group as described later.

3.16 The process for forecasting future reinforcement for EHV networks is set out in greater detail in Appendix 1.

3.17 The output from the network load analysis consists of asset reinforcement costs, A (£); current demand, D (kVA); capacity at which reinforcement would be required, C (kVA); and annual growth rate as a proportion of the demand, g (this final variable being taken from the LTDS data, as mentioned above). In the following analysis i represents the discount rate.

3.18 The fundamental concept behind the FCP approach for the EHV level is that the cost of the reinforcement is recovered between initial time T prior to reinforcement and the time of reinforcement.

3.19 The FCP formula is:

$$FCP = i(A/C)(D/C)^{2i/g-1}/(1-\exp(-iT))$$

This is zero when reinforcement is not required within 10 years.

3.20 The above FCP formula is that for a single time period. The same principle is applied when there is more than one time period, but the multiplying factor is adjusted to ensure that the annual revenue from charges applied to all time periods is equal to the revenue that would be recovered by charging only the period of maximum demand.

3.21 The FCP formula for multiple time periods is:

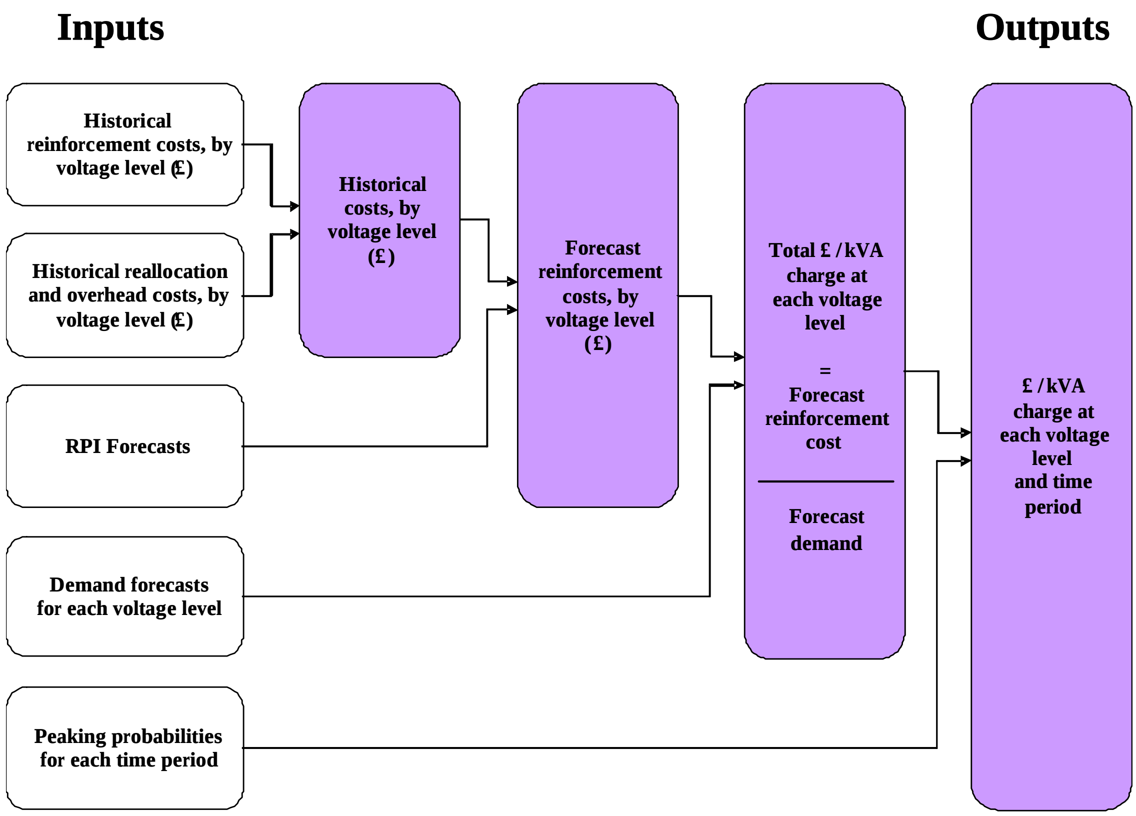
$$FCP(D_j) = [FCP_{single}(D_j)\ FCP(D_{max})\ D_{max}] / \Sigma\ (FCP_{single}(D_j)\ D_j)$$

Where j indicates the individual time period, FCP_{single} is the charge rate for each individual time period, D_i is the demand in time period j. The scaling formula for multiple time periods above ensures that the total revenue recovered through a multi-period approach is equal to the revenue recovered with a single charge rate calculated at the time of maximum demand.

3.22 When setting EHV charge rates, the charge rate calculated for the single period of maximum demand is used. The rates for the separate time periods averaged over all network groups are used in calculating rates for HV and LV within the Tariff model. The total charge rate for each Network Group is the sum of the rates for all forecast reinforcements in that Network Group within the 10-year period. Note that the algorithm uses the current forecast growth rate to estimate the cost recovery period and hence the amount of revenue already assumed to have been recovered.

HV/LV Demand

3.23 A simpler approach is used for determining reinforcement costs at HV and LV levels. The following chart outlines the process to derive the £/kVA/annum charges, for HV/LV demand.



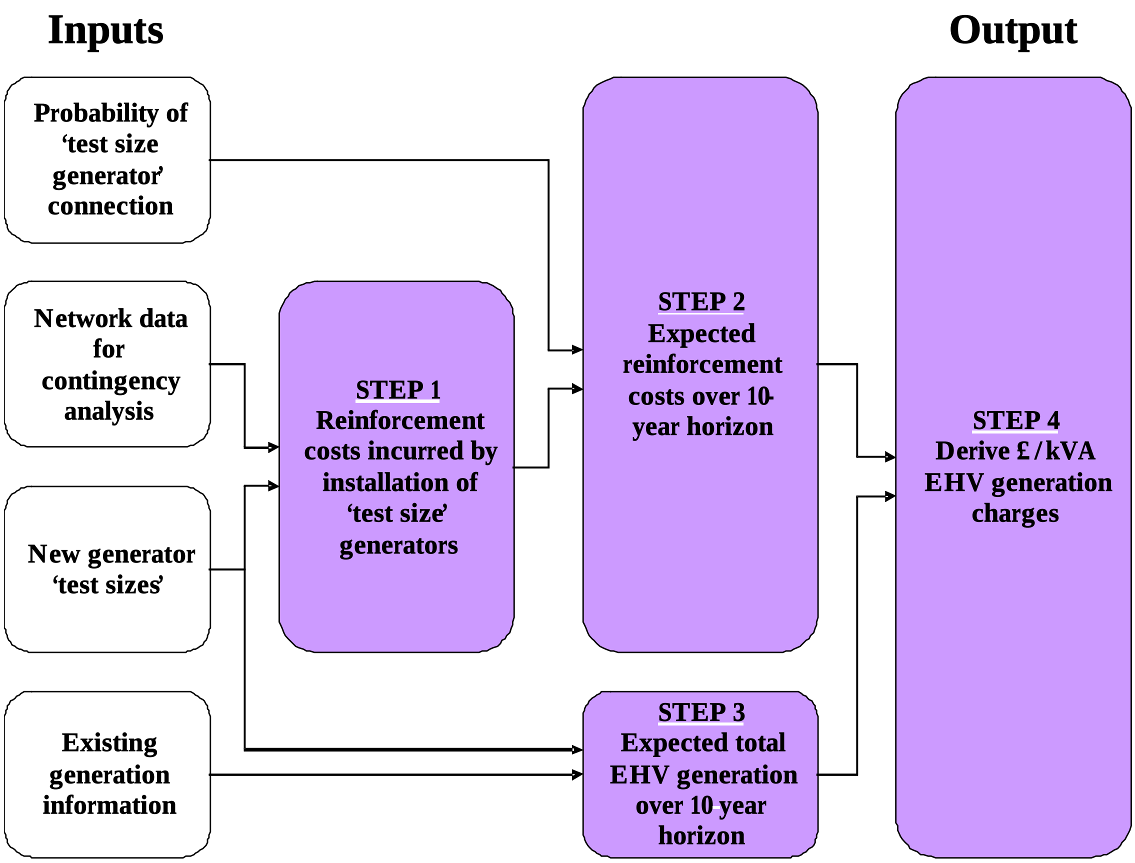
3.24 The annual run rate of reinforcement expenditure is obtained from transparent and auditable information included in the Regulatory Reporting Pack (RRP) sent to the Authority annually, as required by our Distribution Licence[3]. This information is used to project the annual reinforcement expenditure for future years. The most recent available HV and LV reinforcement data is used on a rolling average basis to forecast future years.

3.25 The forward-looking costs are derived from the expected annual reinforcement expenditure at the lower voltage levels typically 11kV, 11/LV and LV. This approach is explained further in the tariff model section below.

[3] Distribution Licence Condition 52: "Price Control Review Information".

EHV and HV – Generation Costs

3.26 The following chart outlines the process to derive the £/kVA/annum Generation costs.



3.27 For generation the 'lumpiness' of connections is captured in the charging model by a 'test size' generator for each voltage level. The probability of such a generator being attached to a Network Group is based on forecasts for total GB DG capacity used in the joint DTI/OFGEM report titled "Review of Distributed Generation", published in May 2007 together with the Energy White Paper[4] and an estimate of the total ratio of DG as a proportion of demand. National Grid's electricity demand projections as per their 7-year statement[5] are used to provide the GB future demand data.

3.28 Once this probabilistic approach has been used, the resultant methodology is similar to that for demand. A test size generator is used per voltage level, and it is chosen to be the 85th percentile of existing and committed future generation[6]. The probability P_V of a 'test size' generator attaching to a Network Group is evaluated by matching the total forecast increase in generation over the next 10 years with this distribution of generation. Appendix 2 shows the calculation of P_V based on the forecast that new generation capacity will be equal to 30% of current demand.

4 "Review of Distributed Generation Report, May 2007", para 152 & 153. Available at http://www.berr.gov.uk/files/file39025.pdf
5 http://ww.nationalgrid.com/uk/sys%5F07/default.asp?sNode=SYS&action=&Exp=Y
6 "Committed future generation" is defined as generators that have accepted a connection offer.

3.29 The output from the network Contingency Analysis gives the headroom, H (kVA), which can be accommodated by the network before reinforcement would be required. If this is greater than the 'test size', $S_{V,}$ then the FCP rate is set to zero. Otherwise the methodology determines the probability that a test size generator will be connected to a Network Group within the next 10 years. It is assumed that there is an equal probability in each of the 10 years. This gives a linear (or stepwise) function of the amount connected multiplied by the probability of connection rising from zero at time zero to the Test Size at the end of the 10 years. On this basis reinforcement is required at $Y = 10\ H/S_V$ years.

3.30 Choosing the FCP rate to be proportional to $k\ \exp(-iY)$, where k is a constant of proportionality, gives equal contributions to the final cost and hence a total cost recovery of :

$$10k(G + S_V/2)$$

where G is the level of existing generation.

3.31 To recover the total cost, allowing for the probability of connection, the FCP rate is set to:

$$A\ P_V \exp(-iY)/(10(G + S_V/2))$$

Where A is the cost of the asset reinforcement.

3.32 For EHV Network Groups the existing generation is that pertaining to the specific Network Group. Since only average generation costs are used in the Tariff model to calculate HV FCP rates, it is the average generation per HV generation location which is used in the above table.

LV Generation Costs

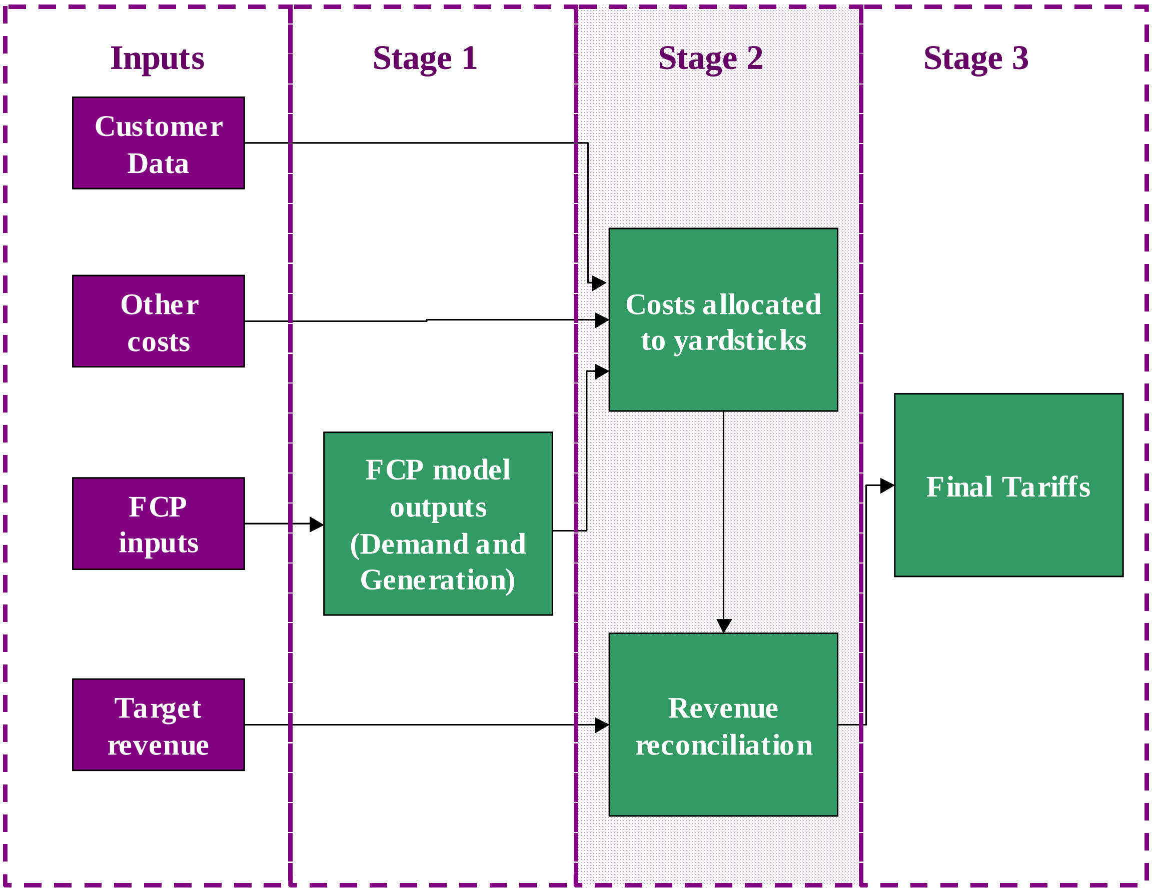
3.33 For LV generation, forward-looking costs are determined from the typical costs of reinforcing the network to connect generation at this voltage level. At the present time, we do not foresee any generator reinforcement costs due to generator connections at LV.

Generation Benefits

3.34 The addition of generation to the network can reduce the requirement for network reinforcement due to increases in demand. The generation benefit corresponds to the extent to which generation is considered to contribute to the reduction in demand when assessing system security at each voltage level. Generation benefits are calculated by multiplying together the demand costs for the voltage of connection as well as the voltages above the point of connection, and the P2/6 Generation Contribution Factors at the voltage of connection. The benefits of connecting generation include the benefits of all voltage levels above the point of connection up to the highest level at which generation can contribute to network security. The overall approach to the costs and benefits included in the generation yardstick is provided in Appendix 3.

4 The tariff model

STAGE 2: DERIVATION OF 'YARDSTICK' COSTS



4.1 The FCP model described in the previous chapter produces a series of £/kVA/annum charges for each network voltage and transformation level and for different times of use. The next step is to calculate yardstick £/kVA/annum charges for sets of customer groups. This is done within the tariff model.

4.2 The tariff model allocates all the appropriately identified costs to the various customer groups (yardsticks) using the most relevant cost driver. The model then applies a voltage-level fixed kVA adder (described in more detail later) to reconcile the overall tariff model revenue with the allowed revenue as per the price control.

4.3 The first step is to identify the relevant yardsticks or customer groups. The objective is to band together for charging purposes customers that exhibit broadly similar characteristics. Each yardstick customer group relates to either demand or generation and will be associated with a specific voltage of connection.

4.4 The following list shows the yardsticks which are used to determine tariffs.

- LV Demand domestic unrestricted (PC1)

- LV Demand domestic restricted (PC2)
- LV Demand Off Peak
- LV Demand non-domestic small unrestricted (PC3)
- LV Demand non-domestic small restricted (PC4)
- LV Demand non-domestic medium restricted (PC5-8) connected to Network
- LV Demand non-domestic medium restricted (PC5-8) connected to Substation
- LV Demand unmetered supplies
- LV Demand non-domestic large restricted (HH) connected to Network
- LV Demand non-domestic large restricted (HH) connected to Substation
- HV Demand non-domestic medium restricted (PC5-8)
- HV Demand non-domestic large restricted (HH) connected to Network
- HV Demand non-domestic large restricted (HH) connected to Substation
- EHV Demand 132kV - site specific
- EHV Demand 33kV - site-specific
- LV Generation (NHH)
- LV Generation(HH)
- HV Generation (HH)
- EHV Generation (site-specific)

Cost allocation to demand customer yardsticks

4.5 The tariff model identifies and allocates the following costs to each of the customer groups listed above:

4.6 **Forward-looking Costs.** These are the output of the forward cost pricing methodology. These costs, in £/kVA, are provided by network voltage and transformation level, as well by time of use. For EHV customers, the FCP costs used are those for the specific network group to which the customer is connected. For HV and LV yardsticks, the costs are allocated on an average basis (i.e. they are not locational). The multiple time period charge rates are used to allocate costs for day and night units for the relevant HV and LV customers. For EHV customers, the charge rate at the time of maximum demand is used. As demand is the cost driver, the forward-looking costs allocated to each customer group are derived by multiplying that customer group's forecast demand, for each of the specified time periods at each voltage and transformation level, by the cost calculated for that voltage level/time period.

4.7 **Operation & Maintenance Costs (O&M).** These consist of inspection, maintenance and fault costs. The historic cost information is taken from the Regulatory Reporting Packs (RRPs) that are submitted to Ofgem each year. The model uses a rolling average of historical O&M costs to smooth out year on year fluctuations, and then costs are uplifted using inflation to estimate the relevant year's costs. The applicable RRP tables also allow the total cost to be accurately split between each voltage and transformation level. The forecast O&M costs for each level of the network are converted into a £/kVA, by dividing this by the forecast maximum demand at each voltage/transformation level. These costs are then equitably attributed to each customer group by using their contribution to the forecast maximum demand.

4.8 **Refurbishment Costs**. These are identified for each level of the network in a similar way as O&M costs. A rolling average of historical RRP Refurbishment cost data (split by network voltage/transformation level) is uplifted for inflation to the relevant year. Similarly to O&M costs, these costs are converted into a £/kVA using the forecast maximum demand at each network level and the costs attributed to each customer group, by reference to their contribution to this forecast maximum demand.

4.9 **Pass-through Costs.** NGET Exit Charges and Licence Fees are both pass-through costs within the distribution price control. Forward looking estimates of NGET Exit Charges are used and converted into £/kVA by using the total calculated maximum demand at the boundary with the transmission system. Each customer group is then allocated its equitable share of exit charges by reference to their contribution to the maximum demand at the NGET boundary. Forward looking estimates of Licence Fee costs are used and converted into a £/customer, using the total number of customers connected and allocated to each customer group on the basis of their forecast customer numbers.

4.10 **Customer Service Costs**. These costs (e.g. call centre costs, MPAS costs) are also sourced from the RRP tables. They are converted into £/customer values for the main billing approaches/systems used by the DNO, and allocated to the customer groups based on their forecast customer numbers.

4.11 In order to allocate the costs above the tariff model also requires a range of other inputs. These include: -

4.12 **Peaking Probabilities.** These represent the likelihood that demand at each voltage level will peak in a particular time period. These are used to allocate FCP costs at the lower voltages to the different time periods.

4.13 **Demand Estimation Coefficients (DECs)**. These are profiling tools used to forecast a customer group's maximum demand in the different time periods from their forecast annual unit consumption. These forecast maximum demands are the basis for the kVA related cost allocations explained above. The DECs are obtained from analysis of historical HH kWh data (either actual or profiled) for each customer group. The formula for calculating a DEC is as follows:

$$\text{DEC} = \text{maximum demand in time period} / \text{total annual MWh}$$

A separate DEC is calculated for each time period and for each customer group. These can then be used to forecast the maximum demand in each time period for the relevant charging year given the forecast of total annual MWh for each customer group.

4.14 **Loss Adjustment Factors.** These are obtained from LAF models and published standard loss adjustment factors, as submitted to Elexon and published on their web site. The loss adjustment factors are used to uplift customer groups' demand at the various network levels, this will affect their allocation of kVA related costs as described above.

4.15 **Forecast Usage Data**. Customer Numbers, consumption (by time of use where appropriate) and maximum capacities (where appropriate) are obtained for each customer group using tariff forecasting techniques.

4.16 For each yardstick group a demand matrix is estimated, detailing the group's forecast kVA peak demand at each voltage level and each time period. These demand estimates are derived by multiplying forecast annual consumption by the Demand Estimation Coefficients, described in paragraph 7.15. This provides demand estimates for the voltage level at which each yardstick group is connected. These estimates are then scaled up by the appropriate published LAFs to estimate the demands placed on higher voltage levels by each yardstick group. The charge rates for each of the five sets of costs described in the paragraphs above are then multiplied by these demand forecasts to generate total cost forecasts for each cost component (marginal, O&M, refurbishment etc.). Finally, these costs are tallied to arrive at a total cost recovery target for each yardstick group. This analysis produces the total cost for each of the customer groups and also provides the split of this cost by network level.

EHV site-specific costs

4.17 The site-specific charges applicable to EHV connections for both demand and generation reflect the actual sole use assets comprising each particular connection. The other elements of EHV charges are calculated according to the same principles described for the other customer groups. The charges relating to sole use assets are calculated using the methodology explained later.

4.18 For EHV customers, the forward-looking costs are taken directly from the actual FCP costs for the Network Group to which they are connected.

Revenue reconciliation for demand

4.19 The next step in the tariff setting process is to reconcile the costs obtained using the approach described above with the allowed revenue forecast for the relevant year. The difference between modelled costs and allowed revenue reflects costs that are not taken into account in the modelling. These are principally network asset related historic costs, such as depreciation and return on capital employed. In order to allocate these costs, a 'per kVA, per voltage level' adder is used, calculated on the basis of the estimated Modern Equivalent Asset Value (MEAV) of the regulated assets at the various network voltage levels. The MEAV of assets deemed to be associated solely with the customers connected at each voltage level are excluded from this calculation, as these assets are likely to have been paid for up-front through connection charges. This results in a different per kVA adder at each particular network voltage level.

Cost allocation to generation customer yardsticks

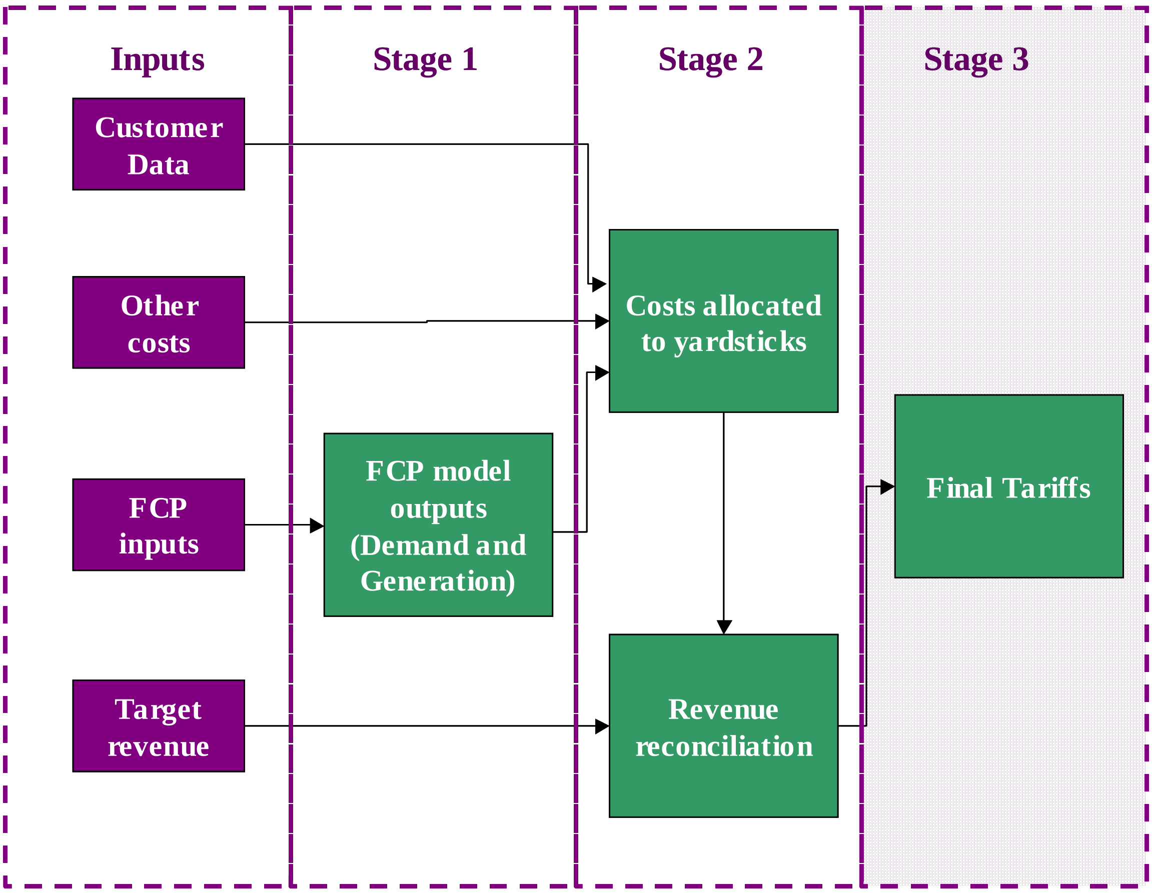
4.20 A yardstick cost is produced for each network group. This is determined by multiplying the appropriate FCP generator costs, determined in section 6, by the total amount of generation capacity forecast for that yardstick. As described, generator costs are only included at the voltage of connection whereas benefits include voltage levels above the point of connection. This produces a yardstick for each generator group. The other costs used in the demand yardsticks are not allocated to generation as these costs are recovered through the demand price control.

4.21 This analysis of generation costs and generation benefits produces the total net cost for each generator customer group.

Revenue reconciliation for generation

4.22 To reconcile the net costs obtained using the approach described above to the generation allowed revenue, a similar approach to revenue reconciliation for demand is used. A fixed kVA adder is applied to each voltage yardstick, with the exception of LV, until the allowed revenue is achieved. The LV yardstick is not included in the revenue reconciliation for generation.

Stage 3. Setting of final tariffs



4.23 Once the total costs per customer group are determined, they are converted into final tariffs by allocating each cost element to the most appropriate tariff component. The structure of the final tariffs are made up of the following elements:

For NHH demand sites:

4.24 Fixed charges. The proportion of pre-scaled costs attributable to the customer service costs and asset-related costs at the voltage of connection and the following level of transformation up is applied to the post-scaled total cost recoverable from the customer group and converted to a fixed charge by reference to the number of customers in the customer group.

4.25 Unit charges. The unit charge will represent the remaining cost. Where the tariff splits the unit rate into a day and night tariff the cost is apportioned between the day and night rates in the same proportion derived from the forward cost allocations.

For HH demand sites (LV & HV):

4.26 **Fixed charges**. The proportion of pre-scaled costs attributable to the customer service costs only is applied to the post-scaled total cost recoverable from the customer group and converted to a fixed charge by reference to the number of customers in the customer group.

4.27 **Capacity charges.** The proportion of pre-scaled costs attributable to the assets-related costs at the voltage of connection and the following level of transformation up is applied to the post-scaled total cost recoverable from the customer group and converted to a capacity charge by reference to the forecast chargeable capacities of the customer group.

4.28 **Unit charges.** The unit charge will represent the remaining cost. Where the tariff splits the unit rate into a day and night tariff the cost is apportioned between the day and night rates in the same proportion derived from the forward cost allocations.

For Generation sites:

4.29 **Capacity charges.** All of the net costs/benefits attributable to a customer group are converted to a capacity charge by reference to the forecast generation capacities of the customer group[7].

For EHV sites:

4.30 The process of setting the final tariffs for EHV sites is described in section 5.

Reactive charges:

4.31 The tariff model also derives the excess reactive power charges applicable to half-hourly LV and HV sites, as described in section 6.

4.32 The graphic below shows a summary of the tariff structure:

[7] Generator charges only apply to 'Relevant DG', as defined in the distribution licence. Further development may be necessary should charges be extended to cover all DG in the future.

NHH Demand Charges

Fixed
Recover proportion of pre - scaled costs attributable customer service and asset - related costs at the voltage of connection and one transformation up

Unit
Recover remaining costs

HH Demand Charges

Fixed
Recover proportion of pre - scaled costs attributable to customer service costs only

Capacity
Recover proportion of pre - scaled costs attributable to asset-related costs only at the voltage of connection and one transformation up

Unit
Recover remaining costs

HV/LV Charges

Capacity
Recover all of the net costs (or net benefits) attributable to each yardstick group

EHV Site -Specific Demand Charges

Fixed
Recover proportion of pre-scaled costs attributable customer service and sole-use assets maintenance costs (derived by applying the average EHV network maintenance cost % to Gross Asset Value of sole use assets)

Capacity
Recover remaining costs (marginal FCP demand and other business scaled costs)

EHV Site -Specific Generation Charges

Fixed
Recover proportion of pre-scaled costs attributable customer service and sole-use assets maintenance costs (derived in the same way as for EHV site-specific demand charges)

Capacity
Recover remaining costs (FCP generator marginal net costs and other business scaled costs)

Excess Reactive Power Charges

Applied only to HH demand where total kVArh exceeds 33% of total kWh

EHV customers do not require separate reactive power charges since they are charged on a kVA basis.

5 EHV site-specific charges

5.1 An EHV site is defined in our licence as being connected to the distribution system at a voltage at or higher than 22kV or at a substation with a primary voltage of 66kV or above. As the costs and circumstances of each EHV site are individual to itself, the use of system charges are determined on a site-specific basis. The site-specific charges are designed to recover the costs (other than those which are recovered through the connection charge) of providing, operating and maintaining the relevant assets between the Grid Supply Point (GSP) and the metered connection exit/entry boundary. The site-specific charge includes the FCP derived costs, which provide cost-reflective forward looking locational price signals to the customer to encourage better utilisation and efficient use of the network.

EHV demand site-specific charges

5.2 The site-specific charges for an EHV demand site are in general calculated as follows:

5.3 **Fixed charge -** This charge recovers customer service costs *(a)* and sole use assets maintenance costs *(b).* The customer service costs are derived on the same basis as for lower voltage customers and recovers customer service, billing and administration costs. The sole use assets maintenance charge is calculated by applying the average EHV network maintenance cost % to the Gross Asset Value (GAV) of the sole use assets. The GAV of the sole use assets is revised annually to take into account inflation (regulatory RPI July – Dec average) and any asset modifications.

Fixed charge (£ / year) = £ (a) + £ (b)

5.4 **Capacity charge -** This charge recovers FCP demand costs *(a)* and other business scaled costs derived on the same basis as for lower voltage networks customers *(b).* The capacity charges are applied to contracted maximum capacity.

Capacity charge (£/kVA) = (a) + (b)

EHV generation site-specific charges

5.5 The site-specific charges for an EHV Generator with registered export are calculated as follows:

5.6 **Fixed charge.** In general, fixed charges are recovered through import charges. However, in cases where there is no import connection or the import is done via a separate supply (i.e., with an LV or HV connection), the GDUoS will contain a fixed charge element calculated as per paragraph 8.2.

5.7 **Capacity charge.** This charge recovers FCP Generator cost(s) associated with the connection *(a),* FCP Generator benefit which is the FCP charge rate multiplied by the P2/6 F-Factor for site *(b)* and the Generation Scaling Adder cost *(c).*

Capacity charge (£/kVA) = (a - b) + (c)

Sole Use Assets

5.8 For existing EHV sites the methodology treats all sole use assets as being fully contributed in line with our current charging policy, unless there is evidence of assets not having been fully contributed. In the later case, the outstanding cost is also recovered from the customer over the nominal life of the assets through a charge comprising of: depreciation calculated on a straight-line basis from the Gross Asset Value of the outstanding sole use assets, a nominal life of 40 years; and a return on capital calculated from the depreciated value of the asset and the cost of capital. In these cases, the sole use charges are added to the fixed charges mentioned above.

5.9 EHV customers fund replacement of the sole use assets as and when required and the charges would be based on the connection charging policy as detailed in our connection charging statement prevailing at the time. SPEN's current connection charging statement is available from SPEN's website at: http://www.scottishpower.com/ConnectionsUseMetering.htm.

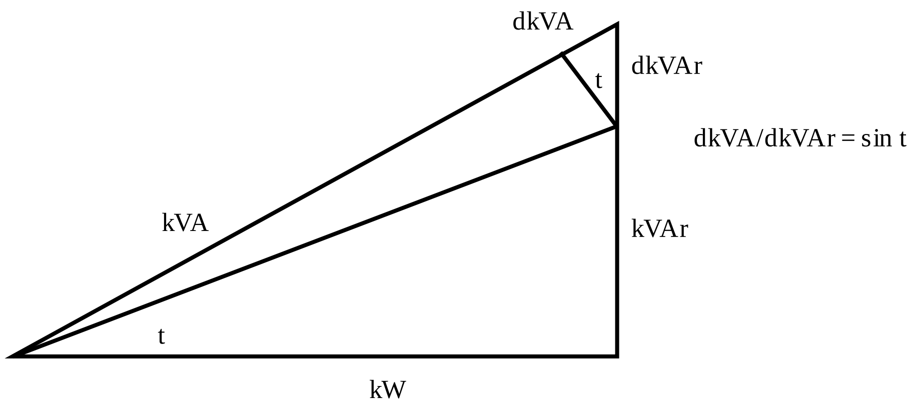
6 Reactive Power charges

6.1 Excess reactive power charges apply to half-hourly demand where total kVArh exceeds 33% of total kWh in a particular charging period (this boundary being equivalent to the average power factor of 0.95 assumed in the pricing model).

6.2 EHV demand customers and generators are charged on a per kVA basis and hence no separate reactive charges are to be levied as the costs are already reflected in the kVA capacity charge. The FCP locational based kVA charge provides strong incentive for the customer to better utilise his contracted capacity.

6.3 The methodology for HV and LV half-hourly metered customers broadly follows that already approved for another DNO[8]. For each customer class the Network Cost and Capacity charges are derived from the tariff model as £/kVA/year (as described in chapters 6 and 7). The Capacity charge is subtracted from the Network Cost as capacity charges (kVA) recover part of the reactive cost element. Furthermore, the Fixed Cost is also removed from the Network Cost.

6.4 The Load Factor for each voltage level is used to derive a cost in p/kVAh. The incremental cost of reactive power is calculated by multiplying this p/kVAh by the rate of increase of the kVA with kVAr. This is sin(t) where the power factor is cos(t). This defines the excess charge rate p/kVArh.



6.5 The power factor for which sin (t) is derived is the average power factor weighted by volume for that customer class for all months in which their power factor is worse than 0.95 based on a previous year's metered data (generators are excluded). The excess charge rate is then applied to all kVArh in excess of one third of the kWh.

6.6 The use of the incremental cost to set reactive charges for HV and LV half-hourly metered customers gives a clear and realistic signal of the costs and benefits of them changing their power factor. Customers may choose to install power factor correction equipment as an alternative to paying the reactive charges, thus diminishing the kVA imposed on the network.

[8] Electricity North West's methodology.

7 USE OF SYSTEM CHARGES

Where our Use of System Charges are published

7.1 SP Manweb's Use of System tariffs are published in our Licence Condition 4A Statement. This can be obtained from our web site, http://www.scottishpower.com/ConnectionsUseMetering.htm.

Appendix 1 - System planning methodology for Identifying the Forward-looking Cost of Reinforcement

Introduction

Forward-looking reinforcement costs are determined with respect to the following categories:
1. Load-related reinforcement costs
2. Generation-related reinforcement costs

Analysis is based on:
1. Publicly available planning information as published annually in the Long Term Development Statement (LC25 Statement), such as:
   - Network data
   - Demand forecast tables
   - Embedded generation data (this is a voluntary additional submission, commonly made in the LTDS)

2. Publicly available planning standards:
   - ER P2/6 Security of Supply standard (as specified in the Distribution Licence)
   - Other standards as specified in the Distribution Code

3. Mechanical/deterministic processes and procedures as identified in this document.

Costs are identified per Network Group and from analysis of the Base Network.

To Assess Load-Related Reinforcement Costs

Process

Load-related reinforcement
- For each Network Group, the impact of additional load is assessed by uniformly increasing the load of the Base Network by 15% in small incremental steps. - For each 1% increment, perform Contingency Analysis in accordance with P2/6 - For loadflow analysis, the Base Network is set with the maximum demand profile given the LTDS and with installed generation set with the appropriate P2/6 F-Factor. - For fault level analysis, the Base Network is set with the maximum demand profile given the LTDS and with installed generation set to nameplate output.
For each stage of reinforcement identify: 1. the percentage increase of load from the Base Network 2. the assets to be reinforced 3. the cost of reinforcement

Procedure

Load-Related Reinforcement of Transformers

1. Identify the firm capacity of each substation and the appropriate maximum demand as forecast in the LTDS (Gross demand).
2. Calculate net demand by subtracting the contribution of embedded generation (as modified by the appropriate P2/6 factor) from the gross demand.
3. Increment gross demand in small steps from 0 to 15% and compare net demand against firm capacity for each increment.

4. If net demand exceeds firm capacity, assume reinforcement is required at the first increment that demand exceeds capacity.

Load-Related Reinforcement of Circuits

1. Identify circuit outage combinations as directed by ER P2/6 for each Network Group.
2. Set the Base Network with the maximum demand profile given in the LTDS and with embedded generation modified by the appropriate P2/6 F-Factor.
3. Increment the demand in small steps from 0 to 15% and perform Contingency Analysis for each increment to identify circuit powerflows.
4. If circuit powerflow exceeds circuit rating then assume reinforcement is required at the first increment that powerflow exceeds rating.

Load-Related Reinforcement of Switchgear

1. For each Network Group identify the fault break and fault make switchgear ratings at the Principal Substation using information published in the LTDS.
2. Identify the existing fault break and fault make level at the Principal Substation using information published in the LTDS.
3. Increment the demand in small steps % from 0 to 15% and assess the contribution to fault current due to additional demand.
4. If fault break or fault make current exceeds switchgear rating then assume reinforcement is required at the first increment that fault current exceeds rating.

To Assess Generator-Related Reinforcement Costs

<u>Process</u>

Generator-related reinforcement
- For each Network Group, the impact of additional generation is assessed by identifying the headroom in the Base Network for additional generation before reinforcement. - New generation is assumed to connect directly to Principal Substation in the Network Group. - The headroom is assessed in terms of switchgear fault ratings and loadflow. - For loadflow analysis, the Base Network is set with the minimum demand profile given in the LTDS and with installed generation set to nameplate output. - For fault level analysis, the Base Network is set with the maximum demand profile given in the LTDS and with installed generation set to nameplate output.
Determine: 1. the existing fault break headroom for additional generation, the assets to be reinforced and the cost of reinforcement. 2. the existing fault make headroom for additional generation, the assets to be reinforced and the cost of reinforcement. 3. the existing reverse-powerflow headroom for additional generation, the assets to be reinforced and the cost of reinforcement.

Procedure

Generator-Related Reinforcement of Transformers

1. For each Network Group identify the minimum demand and maximum generator contribution to the Principal Substation using information published in the LTDS.

2. Calculate net demand by subtracting the contribution of embedded generation from the minimum demand.
3. Where generation is greater than demand, consider the transformer reverse power-flow capabilities.
4. Calculate the reverse-powerflow headroom by subtracting the existing net demand from the reverse-powerflow rating.

Generator-Related Reinforcement of Switchgear

1. For each Network Group identify the fault break and fault make switchgear ratings at the Principal Substation using information published in the LTDS.
2. Identify the existing fault break and fault make level at the Principal Substation using information published in the LTDS.
3. Calculate the fault break and fault make headroom by subtracting the existing fault levels from the switchgear ratings.
4. With respect to fault break contribution, calculate the maximum amount of additional generation that can be connected based on the typical fault current contribution from the generator at fault break time
5. With respect to fault make contribution, calculate the maximum amount of additional generation that can be connected on the typical fault current contribution from the generator at fault make time

Reinforcement Scheme and Costs

Reinforcement of sole-user assets are not considered

Transformers

1. To reinforce a transformer it is assumed an additional transformer of modern equivalent rating will be installed in parallel.
2. The cost of modern equivalent asset reinforcement is based on actual schemes of a similar nature.
3. The equivalence of scheme is assessed in terms of voltage level and transformer rating.

Circuits

1. To reinforce a circuit it is assumed an additional circuit of modern equivalent rating will be installed in parallel.
2. The cost of modern equivalent asset reinforcement is based on actual schemes of a similar nature scaled in respect to circuit length.
3. The equivalence of scheme is assessed in terms of voltage level, circuit rating and whether it is overhead or underground.

Switchgear

1. To reinforce switchgear, the numbers of limiting units of switchgear are identified and are assumed to be replaced with switchgear of modern equivalent rating.
2. The cost of modern equivalent asset reinforcement is based on actual schemes of a similar nature.
3. The equivalence of scheme is assessed in terms of voltage level and transformer rating.

Appendix 2 - Generation probabilities

Generation Probabilities

10 year growth as % of demand =	30%
Total MVA =	6000
New generation =	1800

Voltage	Existing MVA	New MVA	Network Groups	Test Size	Test (MW)	**Pv**
132kV	483.6	818.4	16	75	1200	**0.68**
33kV	330.1	558.6	110	25	2750	**0.20**
HV	244.8	414.3	457	3.4	1553.8	**0.27**
LV	5.2	8.8				
Total	1063.7	1800.0				

Appendix 3 - Overall approach to costs and benefits for generation

Site Specific

FCP Categories	Reinforcement Costs	Demand point of Connection: 132kV Network	Demand point of Connection: 33kV Network	Generation: 132kV	Generation: 33kV
132kV Switchgear	Demand (D1)	D1	D1	-f x D1	-f x D1
	Generation (G1)			G1	
132kV Circuits	Demand (D2)	D2	D2	-f x D2	-f x D2
	Generation (G2)				
132/33kV Transformers	Demand (D3)		D3		-f x D3
	Generation (G3)				G3
33kV Switchgear	Demand (D4)		D4		-f x D4
	Generation (G4)				G4
33kV Circuits	Demand (D5)		D5		-f x D5
	Generation (G5)				
33/11kV Transformers	Demand (D6)				
	Generation (G6)				
11kV Switchgear	Demand (D7)				
	Generation (G7)				

Tariff Model

Tariff Model Categories	Reinforcement Costs	Demand point of Connection: 132kV Network	Demand point of Connection: 33kV BSP Busbars	Demand point of Connection: 33kV Network	Demand point of Connection: HV Network	Demand point of Connection: LV Network	Generation: 132kV	Generation: 33kV	Generation: HV	Generation: LV
132kV Network	Demand	D1 + D2	D1 + D2	D1 + D2	D1 + D2	D1 + D2	-f x (D1 + D2)	-f x (D1 + D2)	-f x (D1 + D2)	-f x (D1 + D2)
	Generation						G1			
132/33kV Substation	Demand		D3 + D4	D3 + D4	D3 + D4	D3 + D4		-f x (D3 + D4)	-f x (D3 + D4)	-f x (D3 + D4)
	Generation							G3 + G4		
33kV Network	Demand			D5	D5	D5		-f x D5	-f x D5	-f x D5
	Generation									
33/11kV Substation	Demand				D6 + D7	D6 + D7			-f x (D6 + D7)	-f x (D6 + D7)
	Generation								G6 + G7	
11kV Circuits	Demand (D8)				D8	D8			-f x D8	-f x D8
	Generation (G8)									
11kV/LV Transformers	Demand (D9)					D9				-f x D9
	Generation (G9)									G9 *
LV Circuits	Demand (D10)					D10				-f x D10
	Generation (G10)									G10 *

* G9 and G10 = zero

Key:

- (white) = values from FCP Model
- (blue) = values derived from RRP data
- (hatched) = marginal cost N/A

Notes:

Nomenclature **Costs are denoted D if related to demand reinforcement and G if related to generation**
Benefits are shown as negative
Benefits are proportional to generation contribution 'f' and are determined using ENA Engineering Technical Report 130 (Application Guide for Assessing the Capacity of Network Containing Distributed Generation (ETR 130) Section 6 considering
('f' for LV generation is typically zero due to the requirement for loss of mains protection and isolation)

Demand

Costs: Demand costs are cumulative from the point of connection up to the highest network voltage
These costs include switchgear, circuits and transformers

Benefits: There are no demand benefits

Generation

Costs: Generation costs are associated with the substation busbar at the point of connection only
These costs include switchgear and transformers
(Circuit costs are not included since generators are assumed to connect directly to the lower voltage side of the transforming busbar)

Benefits: Generation benefits are cumulative from the point of connection up to the highest network voltage level
Benefits are equal to the demand costs, scaled by the generation contribution factor f and include upstream circuits and transformers

Appendix 4 - Statement of Loss Adjustment Factor Methodology for SP Manweb plc's Electricity Distribution Network

THE FOLLOWING SECTION IS NOT APPROVED, AND IS NOT SUBJECT TO APPROVAL BY THE AUTHORITY. IT IS INCLUDED HERE FOR CONVENIENCE ONLY, AND IS NOT PART OF THE APPROVED METHODOLOGY STATEMENT.

1. General Information

This appendix describes the methodologies applied by SP Manweb plc in the calculation of its loss adjustment factors[9] for authorised users of its distribution network in 2006/7.

SP Manweb plc is providing this statement as an appendix to the Use of System Charging Methodology. It details the methodology that is used for the calculation of its published loss adjustment factors and is made available in order to provide clarity and transparency for users of its distribution network. The statement is in addition to the Use of System Charging Methodology statement and is not subject to approval by the Authority.

SP Manweb plc is obliged under Standard Condition 4A of the Distribution Licence to publish a statement of charges for the use of the distribution system that is in a form approved by the Authority. The statement is required to contain "a schedule of adjustment factors to be made for distribution losses" in the company's Condition 4A statement. SP Manweb plc loss adjustment factors are made available to Elexon (and therefore all market participants) through the provision of the dataflow, D0265 for SVA loss adjustment factors and an Elexon prescribed data format for CVA loss adjustment factors. Elexon also make both the SVA and CVA loss adjustment factors available on their website.

Loss adjustment factors are determined through the application of two methodologies. Generic loss adjustment factors are calculated using data obtained from detailed network studies of the distribution system undertaken by external consultants. The site-specific loss adjustment factors are calculated using an electricity industry methodology using the recognised network planning tool. These methodologies are described in detail in sections 2 and 3 below.

2. Generic Loss Adjustment Factors

Generic loss adjustment factors are calculated for all SVA registered authorised users, and are reviewed annually.

A detailed study of distribution losses has been undertaken by external consultants on the SP Manweb network. This study produced theoretical calculations of network losses based on network data such as the number and size of transformers, network lengths etc. Actual network loading data, customer numbers and load factor profiles and loss load factor profiles derived from load research and temperature data were used to determine theoretical values. Loss percentages are calculated for each of the four voltage levels 132kV, 33kV, HV and LV and three transformation levels 132/33kV, 33/HV and HV/LV. The study also identified fixed and variable losses.

[9] Loss Adjustment Factors are sometimes referred to as Line Loss Factors and vice versa.

This information is used in a losses model which is populated with the metered volumes of energy per annum at the various network voltages, including the energy metered at the connection points with National Grid Electricity Transmission's system and the contribution from distributed generation within SP Manweb plc's distribution network.

The model calculates the energy needed to be passed from the next higher voltage level/ transformation point for users connected at different points on the network using the following empirical equation:

$$E_{in} = E_{out} / (1 - Loss\%)$$

Where E_{in} = Energy from higher voltage level,

E_{out} = Energy at lower voltage level,

Loss% = Derived losses relative to throughput.

This is illustrated by the following example:

Energy required at LV for users	9,800GWh
Losses on LV network	2%
Energy required from HV/ LV transformation	10,000GWh

This is repeated through the voltage and transformation levels to calculate the theoretical losses, based on the detailed study, at each voltage level and transformation level for customers connected at different points on the network. The total theoretical losses are then compared to the total measured losses and adjusted to match. To calculate the loss adjustment factor for a particular connection point, the losses associated with the connection are divided by the annual consumption. Day and night loss factors are derived from the detailed study which calculated ratios of day and night loss factor relative to the total losses.

The loss adjustment factors for generators connected at different points on the network are determined from the variable losses from the network above the voltage of connection.

3. Site Specific Loss Adjustment Factors

Site specific loss adjustment factors are calculated for all CVA registered authorised users and, where requested, EHV SVA registered authorised users. These loss adjustment factors are re-calculated following a material change to network data.

These loss adjustment factors are determined by the use of a network model on which the general network load and the site load is adjusted to be at its RMS value (over one year). RMS is used, rather than average as losses are proportional to the square of current. The method is to take the square root of the sum of the squares of average demand and the standard deviation of that demand. The kW variable (copper) loss so derived from the network model will be equivalent to that derived by calculating the sum of all the losses (for each hour) over the same period.

It is then possible to identify the fixed and variable losses attributable to a particular user by determining the total losses between connection point with National Grid Electricity Transmission's system (F.M.S. Metering) and the point of connection with the Customer by the method of substitution.

4. Generation Customers

The treatment of generation sites is in accordance with the principles set out in industry guidance document SSC (OP) 1390 (Revised) - “Guidance note for the calculation of loss factors for embedded generators in settlement”.

The guidance states that the accepted method of calculation should be by use of substitution. Load flow and energy loss calculations are carried out with the generator both connected to and disconnected from the network. The network and generation are set at their RMS values. The loss calculation itself is carried out exactly as for load customers, the difference in total system losses is then allocated to the generator.

Where more than one site specific generator exists locally on the network then the substitution method is carried out similarly with the generators being connected to the losses model in the order of their date of commissioning. E.g. For a network containing two generators the following calculations are performed:

- Total energy loss calculated with no generation (T)
- Total energy loss calculated with Generator 1 connected (TG1)
- Total energy loss calculated with Generator 2 connected (TG2)

Difference in loss attributable to Generator 1 = T – TG1

Difference in loss attributable to Generator 2 = TG2 – TG1

Loss adjustment factors for generation whose output causes an overall reduction in system losses will be > 1. Generation whose output causes an overall increase in system losses will have loss adjustment factors of < 1.

The loss adjustment factor is given by the losses attributable to the generator in each time period averaged over the number of units generated.

--------------------- END OF UNAPPROVED SECTION -------------------

Appendix 5 – Glossary of terms

AC	Alternating Current
Act	The Electricity Act 1989 as amended by the Utilities Act 2000.
Authority	The Gas and Electricity Markets Authority as established by the Utilities Act.
Base Network	This is used for determining costs and is as detailed in the Long Term Development Statement (published in accordance with Licence condition 25). The Base Network used is the existing and committed network that is expected to exist in the December of the year for which costs are calculated. The Base Network is a full model of the network from GSP to primary substation LV busbar
BSC	Balancing and Settlements Code – wholesale electricity trading arrangements introduced in England and Wales 2001 are designed to provide greater competition, while maintaining a secure and reliable electricity system.
BSP	Bulk Supply Point. Generally refers to 132/33kV, 132/11 or 66/22kV in England and Wales. The term BSP is not applicable in Scotland.
Contingency analysis	AC loadflow studies to model the effect of various outages on the Base Network.
DC	The Distribution Code, the document produced by each Distributor in accordance with Condition 9 of its Licence and approved by Ofgem to define the technical aspects and planning criteria of the working relationship between the Distributor and all those connected to its Distribution System.
DEC	Demand Estimation Coefficient. Profiling tool used to forecast a customer group's maximum demand in the different time periods from their forecast annual unit consumption.
DG	Distributed Generation. Generation connected to the Distribution networks (132 kV or lower in England and Wales and 33 kV or lower in Scotland).
Distribution Licence	Refers to the Electricity Distribution Licence.
DNO	Distribution Network Operator. A licensed distributor which operated electricity distribution networks in distribution service areas.

DUoS	Distribution Use of System Charges.
EHV	Extra High Voltage. It refers to sections of the network at voltages at or higher than 22kV.
Embedded Generation	An alternative name for Distributed Generation (DG).
ER P2/6	Engineering Recommendation P2/6, Security of Supply (July 2006). Sometimes referred to in the text as “P2/6”.
FCP	Forward Cost Pricing. The FCP approach constitutes the core of the G3 methodology.
FE	Frontier Economics.
G3	Group of three DNOs working together to develop a methodology for Use of System charges. The companies are ScottishPower EnergyNetworks, SSE Power Distribution and Central Networks.
GB	Great Britain.
GDUoS	Generation Distribution Use of System Charges. Charges paid by generation customers connected to a distribution network.
GSP	Grid Supply Point. Generally refers to 400/132kV or 275/66kV in England and Wales and 132/33kV in Scotland.
HH	Half Hourly. It refers to customers with Half Hourly metering arrangements.
HV	High Voltage. It refers to sections of the network with voltages exceeding 1000 Volts but lower than 22kV.
LAF	Loss Adjustment Factors. These are factors, used in the settlement process, which account for losses in the network for each customer class.
LTDS	Long Term Development Statement. This statement is produced by the DNOs in compliance with their Licence Condition 25.
LV	Low Voltage. It refers to sections of the network with voltages not exceeding 1000 Volts.
MEAV	Modern Equivalent Asset Value.
MRA	Master Registration Agreement. Means the agreement of that name dated 1 June 1998.
Network Group	A practical group defined by physical, operational and technical boundaries and includes all voltage levels above HV (11kV). Network Groups are defined as the network normally supplied from a Grid Supply Point (GSP) or a Bulk Supply Point (BSP). In situations where GSP/BSPs are operated in parallel, the parallel GSP/BSP groups are considered as one Network Group. In Scotland there is only a single layer of Network Group from GSP to HV. In England and Wales two layers of Network Group are

	considered: GSP to BSP and BSP to HV to reflect network topology. At the charging stage, customers connected to the second layer of Network Group (BSP to HV) will also pick up a per kVA proportion of the first layer (GSP to BSP) costs.
NGET	National Grid Electricity Transmission. The transmission network operator for GB.
NHH	Non Half Hourly. It refers to customers without Half Hourly metering arrangements.
NPV	Net Present Value.
O&M	Operation and Maintenance.
OFGEM	Ofgem is the Office of Gas and Electricity Markets, regulating gas and electricity industries in Great Britain. Ofgem operate under the governance of the Authority, which sets all major decisions and policy priorities.
PC	Profile Class. Code use in Settlements to are used to group customers with similar characteristics.
Primary Substation	A 33/11, 33/6.6, 22/11 or 22/6.6 kV substation.
Principal Substation	This is the substation which connects the network group to a higher voltage level. This is typically a GSP or a BSP. In Network Groups where there is more than one substation connecting the group to a higher voltage level, the substation with the largest powerflow (in either direction) under normal Base Network conditions is considered to be the Principal Substation.
RRP	Regulatory Reporting Pack. An information pack sent by the DNO to the Authority annually, in compliance with licence condition 52: “Price Control Review Information”.
Security of Supply	Defined in Engineering Recommendation P2/6. The capability of a system to maintain supply to a defined level of demand under defined outage conditions.
SLC	Standard Licence Condition. These are conditions that licensees must comply with as part of their licences.
SPD	Scottish Power Distribution Ltd. The licensed DNO in south and central Scotland.
SPEN	ScottishPower EnergyNetworks. A division of the Scottish Power group, which is the public-facing identity of SPD, SPM and SPT.
SPM	Scottish Power Manweb plc. The licensed DNO in Merseyside, Cheshire and North Wales.
SPT	Scottish Power Transmission. The licensed transmission owner in south and central Scotland and the owner of the Scottish land-based

	part of the interconnector linking Scotland and Northern Ireland.
Yardsticks	Group of customers that exhibit broadly similar characteristics banded together for charging purposes. Each yardstick customer group relates to either demand or generation and is associated with a specific voltage of connection