SCHEDULE 17 – EHV CHARGING METHODOLOGY (FCP MODEL)

1 INTRODUCTION

1.1 This Schedule 17 sets out one of the two EHV Distribution Charging Methodologies (**EDCM**). The other EDCM methodology is set out in Schedule 18.

1.2 This Schedule 17 sets out the methods, principles, and assumptions underpinning the calculation of Use of System Charges for EDCM Connectees

Main Steps

1.3 The EDCM method involves four main steps.

1.4 Step 1 is the application of load flow techniques and the LRIC or FCP methodologies to determine two EDCM tariff elements, known as charge 1 and charge 2:

(a) Charge 1 represents costs associated with demand-led reinforcement, estimated by reference to power flows in the maximum demand scenario; and

(b) Charge 2 represents costs associated with generation-led reinforcement, estimated by reference to power flows in the minimum demand scenario.

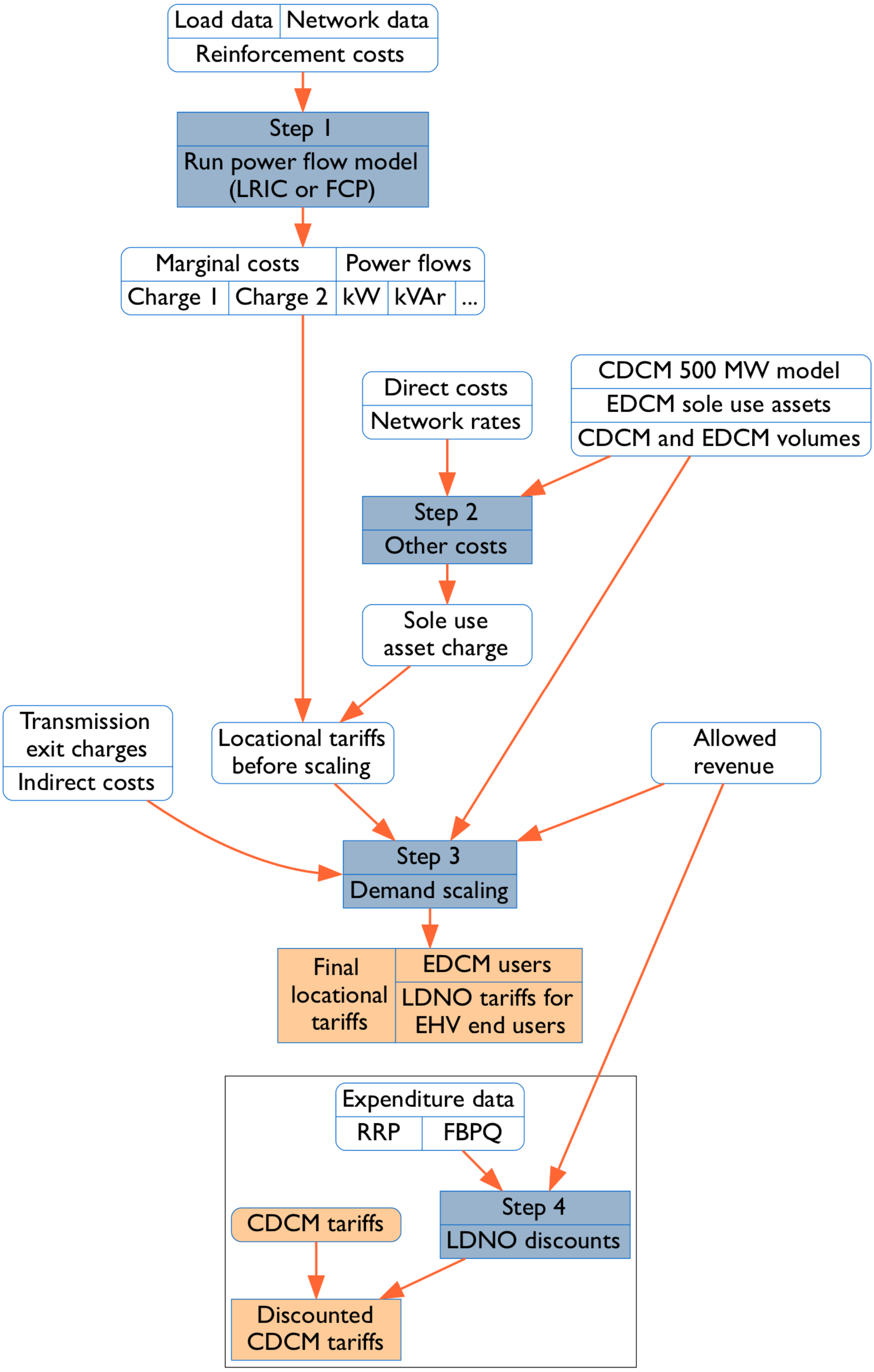
1.5 Step 2 involves the allocation of DNO costs to customers using appropriate cost drivers.

1.6 Step 3 adds a scaling element to tariffs which is related to allowed revenue.

1.7 Step 4 uses CDCM tariffs to determine the element of portfolio tariffs to be applied in the case of LDNOs who are supplied from the DNO's network at voltages higher than the scope of CDCM tariffs.

1.8 Figure 1 provides a diagrammatic overview of the steps involved.

Figure 1 Diagrammatic overview of the EDCM



2 FORWARD COST PRICING ANALYSIS

Introduction

2.1 The Forward Cost Pricing (**FCP**) model is used to calculate annual incremental charges for EDCM Connectees. A fundamental principle of the FCP model is that the revenue recovery generated from its incremental charges is equal to the expected cost of reinforcement. These incremental charges provide cost signals relative to the available capacity in a Network Group, the expected cost of reinforcement of the Network Group and the time before the reinforcement is expected to be necessary. Load and generation incremental charges are derived separately.

2.2 The key FCP modelling steps consist of:

(a) configuration of the Authorised Network Model;

(b) development of demand data sets;

(c) definition of Network Groups;

(d) power flow analyses:

(i) assessment of network security requirements (load);

(ii) assessment of network security requirements (generation);

(e) calculation of reinforcement costs;

(f) calculation of FCP load incremental charges (£/kVA/annum); and

(g) calculation of FCP generation incremental charges (£/kVA/annum).

Configuration of the Authorised Network Model

2.3 Power flow analyses are performed on the Authorised Network Model. This is a representation of the DNO Party’s EHV network (from the Grid Supply Point level down to and including the HV busbars at the EHV/HV transformation level) expected to exist and be operational in the Regulatory Year for which Use of System Charges are being calculated.

2.4 Guidance on the configuration of the Authorised Network Model is provided in the section 4 (Authorised Network Model) of Annex 1.

Development of Network Demand Data sets

2.5 Load data used in the power flow analyses is based on network demand data from the DNO Party's Long Term Development Statement (or LTDS), which contains a five-year forecast of substation maximum demands. A 10-year forecast is derived by extrapolation of the five-year forecast. Existing generation data is based on the Maximum Export Capacities of EDCM Generation.

2.6 Guidance on the development of the Network Demand Data sets is provided in section 5 (Network Demand Data) of Annex 1.

Definition of Network Groups

2.7 The Authorised Network Model is split into Network Groups, thereby reflecting the zonal nature of the FCP model. A Network Group is a contained portion of the Authorised Network Model defined by physical, operational and technical boundaries that is not electrically connected to another part of the network at the same voltage level under normal operating conditions. A Network Group is defined as the network normally supplied from a Grid Supply Point (GSP) substation, a Bulk Supply Point (BSP) substation, or a Primary Substation. In situations where GSP substations, BSP substations or Primary Substations are operated in parallel, the network associated with such parallel GSP substations, BSP substations or Primary Substations is considered as one Network Group.

2.8 Guidance relating to the definition of Network Groups is presented in section 6 (Network Groups) of Annex 1.

Power Flow Analyses

2.9 Power Flow analyses are undertaken using AC load flow methods.

Assessment of network security requirements (load)

2.10 Contingency analyses are performed on the Authorised Network Model to which the relevant Network Demand Data sets have been applied. This is done in order to identify all load-related reinforcements expected within the 10-year horizon in line with network planning security requirements (as can be found in ER P2/6). N-1 and, where required, N-2 contingency analyses are performed on the Authorised Network Model for each year within the 10-year horizon.

2.11 Reinforcements identified within the 10-year horizon are used to determine FCP load incremental charges. As the power flow analyses progress through the 10-year planning period the same reinforcements will be identified - only newly-identified reinforcements in each year are considered in order to avoid double-counting. The analysis considers thermal ratings only.

2.12 Guidance relating to these power flow analyses is presented in section 7 (Power flow analysis process) of Annex 1.

Assessment of network security requirements (generation)

2.13 Contingency analyses are performed on the Authorised Network Model to which the relevant Network Demand Data sets have been applied. This is done in order to identify all generation-driven reinforcements that are likely within the 10-year horizon. Only N-1 contingency analyses are performed and only thermal ratings are considered.

2.14 The assessment of network security requirements for generation does not involve sequential 10-year power flow analyses. Rather, the first year load forecast is applied to the Authorised Network Model and the effect of new EDCM Generation is modelled by the sequential installation of discrete 'test-size' generators (TSGs) in each Network Group. The TSG represents the largest 'likely' generator that could connect to the network at some point over the study period and is used to stress-test the Authorised Network Model to check for reinforcements. 'Substation' TSGs are connected to 'source' substations which supply the considered Network Group, while 'Circuit' TSGs are connected around the perimeter of the considered Network Group in turn. The output of the TSG is gradually increased to full capacity and N-1 contingency analyses are performed at each increment of output.

2.15 Guidance relating to the sizing and application of TSGs and these power flow analyses is presented in section 7.10 (**Test Size Generators**) of Annex 1.

2.16 The Headroom associated with a TSG with respect to a Branch is its maximum output that does not cause overload. The Headroom is used to estimate the time before reinforcement and reinforcements identified due to the installation of TSGs are used to determine FCP generation incremental charges. In the event a Branch is overloaded by the installation of multiple TSGs, account is taken of the earliest time to expected overload and the characteristics of the TSGs that trigger it.

2.17 Guidance relating to the treatment of reinforcements for calculating FCP generation incremental charges is presented in section 7 (Power flow analysis process) of Annex 1.

Calculation of reinforcement costs

2.18 It is assumed that the reinforcement or any Branch is undertaken in a standardised way with standardised costs. In practice, the design data used by the DNO Party to prepare offers for connection to its Distribution System should be used when determining the extent and likely cost of reinforcement.

2.19 Guidance relating to the calculation of reinforcement costs is presented in section 8 (Calculation of reinforcement costs) of Annex 1.

Calculation of FCP load incremental charges

2.20 The FCP load incremental charge for a Network Group is a derived from all expected reinforcements identified within the 10-year horizon period within that Network Group.

2.21 The FCP load incremental charging function is in integral form with exponential load growth and continuous discounting applied. The following charging function is used to derive the Network Group FCP load incremental charge (£/kVA/annum) for load customers:

$$FCP_{load} = \sum_j \frac{i\left(\frac{A_j}{C_l}\right)\left(\frac{D}{C_l}\right)^{\frac{2i}{g_l}-1}}{1-e^{-iT}}$$

Where:

FCP_{load}	=	FCP load incremental charge (£/kVA/annum)
j	=	index of Branch whose reinforcement is required in the planning period
i	=	discount rate, which is assumed to be the pre-tax cost of capital set by the Authority as part of the then most recent review of the charge restriction conditions applying under the DNO Party’s Distribution Licence
A_j	=	total cost (£) of asset “j” reinforcement in the considered Network Group over 10-year period
l	=	index of the total load level at which reinforcement of Branch “j” is required
C_l	=	total demand (kVA) of the Network Group, in the Maximum Demand Scenario, in the year Y_l in which reinforcement of Branch “j” is required
D	=	total demand (kVA) in the Network Group in the first year of the 10-year horizon in the Maximum Demand scenario
g_l	=	annual average load growth rate corresponding to the year in which the reinforcement is expected to be required (see below)
T	=	10 years over which the reinforcement cost is recovered

2.22 The annual average Network Group load growth rate corresponding to the year in which the reinforcement is expected, g_l, is calculated by:

$$g_l = \frac{\ln(\frac{C_l}{D})}{Y_l}$$

Where:

g_l	=	annual average load growth rate corresponding to the year in which the reinforcement is expected to be required
Y_l	=	number of years before the reinforcement of Branch "j" is required
C_l	=	total demand (kVA) of the Network Group, in the Maximum Demand Scenario, in the year Y_l in which reinforcement of Branch "j" is required
D	=	total demand (kVA) in the Network Group in the first year of the 10-year horizon in the Maximum Demand scenario

2.23 Guidance relating to the calculation and application of FCP load incremental charges is presented in section 9.1 (FCP load incremental charge) of Annex 1.

Calculation of FCP generation incremental charges

2.24 The FCP generation incremental charge for a Network Group is a derived from all expected reinforcements identified within that Network Group when TSGs were installed to test the impact of new generation on that Network Group. The cost of reinforcement of a Network Group is spread across all existing and expected new ECDM Generation associated with that Network Group network over the 10-year horizon period.

Time to Reinforcement

2.25 The present value of the cost of reinforcement of an overloaded Branch is a function of the time before which the expected reinforcement is required. The time to reinforcement is derived from:

$$Y_l = \frac{10H_l}{S_v}$$

Where:

Y_l	=	number of years before the reinforcement of Branch "j" is required.
H_l	=	TSG headroom for Branch "j". This is the maximum output from the TSG that does not cause Branch "j" to become overloaded
l		index of TSG that causes triggers the earliest time to reinforcement of Branch "j"
S_v	=	size of the TSG at voltage level "v". This may take the value of S_{VS} if a 'Substation' TSG has been applied or S_{VC} if a 'Circuit' TSG has been applied.

S_{vs} = 'Substation' TSG
S_{vc} = 'Circuit' TSG

2.26 Guidance relating to the calculation of the time to reinforcement is presented in section 9 (Calculation of Network Group incremental charges) of Annex 1.

Probability of connection of new generation

2.27 The present value of the cost of reinforcement is scaled by the probability of generation actually connecting within the next 10 years. It is assumed that there is an equal probability of connection in each year of the 10-year period. The probability is derived by:

(a) total new generation for the 10-year period is forecast by the DNO Party, using generation expected to connect to the Authorised Network Model. The total forecast is further disaggregated by voltage levels relevant to the DNO Party; and

(b) the generation forecast at each voltage level is divided by the total amount of TSG generation (in MW) installed to test that voltage level during the power flow analyses.

2.28 The probability factor is given by the following equation:

$$P_V = \frac{G_V}{M_{VS}S_{VS} + M_{VC}S_{VC}}$$

Where:

P_v = probability of new generation at voltage level "v"
G_v = the DNO Party's forecast new generation for voltage level "v"
M_{vs} = total number of 'Substation' TSGs connected at voltage level "v" in the power flow analysis of all Network Groups
S_{vs} = size (capacity) of 'Substation' TSG
M_{vc} = total number of "Circuit" TSGs connected at voltage level "v" in the power flow analysis of all Network Groups
S_{vc} = size (capacity) of 'Circuit' TSG

2.29 This probability is applied to the present value of the cost of reinforcement when the overload is triggered by the installation of a single TSG. For cases in which the reinforcement of a Branch is triggered by the installation of multiple TSGs, composite probability is applied instead. This is calculated by:

$$P_V^j = 1 - (1 - P_V)^{M_S^j + M_C^j}$$

Where:

P_v^j	=	composite probability associated with asset "j"
P_v		probability of new generation at voltage level "v"
M_s^j	=	number of "Substation" TSGs that cause overload of Branch "j"
M_c^j	=	number of "Circuit" TSGs that cause overload of Branch "j"

2.30 In the event there is no forecast generation at a particular voltage level, the probability factor, P_v, associated with the nearest voltage level is used. Guidance relating to the calculation of probabilities is presented in section 9 (Calculation of Network Group incremental charges) of Annex 1.

Total 10-year generation

2.31 Total generation expected to connect to the Distribution System over the 10-year horizon period is given by:

$$G_{total} = 10(G_{existing} + G_{new})$$

Where:

G_{total}	=	total 10-year EDCM Generation connected within the considered Network Group
$G_{existing}$	=	existing EDCM Generation connected within the considered Network Group
G_{new}	=	new EDCM Generation connected within the considered Network Group

2.32 The annual average new EDCM Generation expected to connect to the Distribution System over the 10-year horizon period is given by:

$$G_{new} = 0.5 P_V (M_S S_{VS} + M_C S_{VC}),$$

Where:

G_{new}	=	new EDCM Generation connected within the considered Network Group
M_s	=	number of 'Substation' TSGs connected to test the considered Network Group
M_c	=	number of 'Circuit' TSGs connected to test the considered Network Group
S_{vs}	=	size (capacity) of 'Substation' TSG
S_{vc}	=	size (capacity) of 'Circuit' TSG

2.33 Total generation in the Network Group under consideration over the 10-year horizon period is given by:

$$G_{total} = 10\,(G_{existing} + 0.5P_V\,(M_S S_{VS} + M_C S_{VC}))$$

Where:

G_{total}	=	total 10-year EDCM Generation connected within the considered Network Group
$G_{existing}$	=	existing EDCM Generation connected within the considered Network Group
G_{new}	=	new EDCM Generation expected to connected within the considered Network Group
M_s	=	number of 'Substation' TSGs connected to test the considered Network Group
M_c	=	number of 'Circuit' TSGs connected to test the considered Network Group
S_{vs}	=	size (capacity) of 'Substation' TSG
S_{vc}	=	size (capacity) of 'Circuit' TSG

FCP generation incremental charge

2.34 The FCP generation incremental charge for a given Network Group is calculated by spreading the cost of reinforcement of the Network Group across the total expected EDCM Generation within that Network Group and within Network Groups connected downstream. Continuous discounting is applied within the FCP generation incremental charging function. This is given by:

$$FCP_{generation} = \frac{\sum_j P_V^j \cdot A_j \cdot e^{-iY_l}}{G_{total} + \sum_k G_{total}^k}$$

Where:

$FCP_{generation}$	=	FCP generation incremental charge (£/kVA/annum)
P_v^j	=	composite probability associated with Branch "j"
A_j	=	total cost (£) of Branch "j" reinforcement in the considered Network Group over 10 year period
i	=	discount rate, which is assumed to be the pre-tax cost of capital set by the Authority as part of the then most recent review of the charge restriction conditions applying under the DNO Party's Distribution Licence
Y_l	=	earliest number of years before the reinforcement of Branch "j" is required
G_{total}	=	total 10-year EDCM Generation in the considered Network Group
G^k_{total}	=	total 10-year EDCM Generation in a Network Group downstream of the considered Network

k = index of downstream Network Group connected to the considered Network Group

2.35 Guidance relating to the calculation and application of FCP generation incremental charges is presented in section 9.4 (Calculation of Network Group incremental charges) of Annex 1.

Outputs

2.36 The outputs of the FCP modelling are:

(a) Network Group ID;

(b) Charge 1: Demand (load) charge (£/kVA/annum);

(c) Charge 2: Demand (generation) charge (£/kVA/annum);

(d) Parent Network Group ID;

(e) Active Power (kW) of Demand (Load) for Maximum Demand Scenario;

(f) Reactive Power (kVAr) of Demand (Load) for Maximum Demand Scenario;

(g) Active Power (kW) of Demand (Load) for Minimum Demand Scenario;

(h) Reactive Power (kVAr) of Demand (Load) for Minimum Demand Scenario;

(i) Active Power (kW) of Demand (Generation) for Maximum Demand Scenario;

(j) Reactive Power (kVAr) of Demand (Generation) for Maximum Demand Scenario;

(k) Active Power (kW) of Demand (Generation) for Minimum Demand Scenario; and

(l) Reactive Power (kVAr) of Demand (Generation) for Minimum Demand Scenario.

3 EDCM demand tariff components for end users

3.1 This section sets out the different demand tariff components that will apply to customers (end users) under the EDCM. Tariff components are the outputs of the EDCM and make up the distribution use of system charges applied to customers.

3.2 Under the EDCM, a customer is defined as a site as determined in the bilateral connection agreement. However, where a site is a group of connection points that relate to a single bilateral connection agreement, these connection points are treated as a single customer for charging purposes.

3.3 The unit of application of EDCM charges is a "tariff". Each tariff represents an entry in the EDCM model input data sheet, and therefore would have a full set of outputs, i.e. EDCM tariff components.

3.4 The EDCM currently recognises only import (demand) tariffs.

3.5 Demand tariffs under the EDCM comprise the following individual components:

- Fixed charges.
- Import capacity charges.
- Exceeded import capacity charges.
- Unit rate charges for consumption at the time of DNO peak (super-red time band).

3.6 The EDCM tariff components for demand are listed in table 1.

Table 1 Tariff components for import tariffs

Tariff component	Unit
Fixed charge	p/day
Import capacity charge	p/kVA/day
Exceeded import capacity charge	p/kVA/day
Super-red unit charge	p/kWh

3.7 The next section details the calculation of the EDCM tariff elements that determine the tariff components described above.

4 Calculation of EDCM tariff components

4.1 EDCM tariff components are derived from tariff elements. This section describes the method for calculating each of these tariff elements.

5 Application of FCP charge 1 to demand tariffs

5.1 The tariffs for the application of charge 1 is given by the formulas:

For customers with zero average kW/kVA:

[p/kWh super-red rate] = ([parent charge 1 £/kVA/yr] * (abs[A1] / (SQRT(A1^2 + R1^2)) / [Super-red hours] *100) + ([grandparent charge 1 £/kVA/yr] * (abs[A2] / (SQRT(A2^2 + R2^2)) / [Super-red hours] *100) [p/kVA/day capacity charge] = ([network charge 1 £/kVA/year] /[days in charging year]*100) + ([parent charge 1 £/kVA/yr] * (–R1 * Average kVAr/kVA]) / (SQRT(A1^2 + R1^2)) / [days in charging year] *100) + ([grandparent charge 1 £/kVA/yr] * (–R2 * [Average kVAr/kVA]) / (SQRT(A2^2 + R2^2)) / [days in charging year] *100)

For all other customers:

[p/kWh super-red rate] = [parent charge 1 £/kVA/yr] * (abs[A1] – (R1 * ([Average kVAr/kVA] / [Average kW/kVA])) / (SQRT(A1^2 + R1^2)) / [Super-red hours] *100 + ([grandparent charge 1 £/kVA/yr] * (abs[A2] – (R2 * ([Average kVAr/kVA] / [Average kW/kVA])) / (SQRT(A2^2 + R2^2)) / [Super-red hours] *100)

[p/kVA/day capacity charge] = [network group charge 1 £/kVA/year] /[days in charging year]*100

Where:

A1 and R1 are the values of the active power flow and reactive power flow modelled through the parent network group in the maximum demand scenario.

A2 and R2 are the values of the active power flow and reactive power flow modelled through the grandparent network group in the maximum demand scenario.

If both A1 and R1 are equal to zero, in respect of that network level in the formulas above, the term (abs[A1] / (SQRT(A1^2 + R1^2)) is set equal to 1, (–R1 * Average kVAr/kVA]) / (SQRT(A1^2 + R1^2)) is set equal to zero, and ([Average kVAr/kVA] / [Average kW/kVA])) / (SQRT(A1^2 + R1^2)) is also set to zero.

If both A2 and R2 are equal to zero, in respect of that network level in the formulas above, the term (abs[A2] / (SQRT(A2^2 + R2^2)) is set equal to 1, (–R2 * Average kVAr/kVA]) / (SQRT(A2^2 + R2^2)) is set equal to zero, and ([Average kVAr/kVA] / [Average kW/kVA])) / (SQRT(A2^2 + R2^2)) is also set to zero.

Super red hours are the number of hours in the DNO's super-red time band.

The average kW/kVA and average kVAr/kVA figures are forecasts for the charging year, based on data from the most recent regulatory year for which data were available in time for setting charges for the charging year. Specifically, active and reactive power consumptions are averaged over a super-red time band, which is a seasonal time of day period determined by the DNO to reflect the time of peak, and then divided by import capacity (averaged over the same financial year). If the DNO considers that the reactive consumption data relates to export rather than import (e.g. the average kVAr figure exceeds half of the import capacity) then the import capacity in the denominator should be replaced by the export capacity of the same customer. The average kVAr divided by kVA is restricted to be such that the combined active and reactive power flows cannot exceed the maximum import capacity. Should the restricted kVAr divided by kVA be negative, then it is set to zero.

6 Application of FCP charge 2 to demand

6.1 Charge 2 is not applied to demand.

7 No application of negative charges

7.1 Under FCP, charge 1 is either zero or positive. Negative charge 1 values are not applied in any demand tariffs.

8 Demand side management (DSM)

8.1 Some EDCM users are subject to demand side management (DSM) agreements.

8.2 For customers with DSM agreements, let "chargeable capacity" be equal to the maximum import capacity minus the capacity that is subject to restrictions under a DSM agreement. These restrictions would take into account any seasonal variations built into these agreements.

8.3 For demand customers with DSM agreements, DSM-adjusted local and remote (or parent and grandparent) elements of the FCP charge are calculated as the product of the ratio of "chargeable capacity" to maximum import capacity and the unadjusted elements of the FCP charge. Where the maximum import capacity is zero, this ratio is set to 1. The DSM-adjusted local element of the FCP charge 1 is applied to the maximum import capacity, and the DSM-adjusted remote (or parent and grandparent) element of the FCP charge 1 is applied to units consumed during the super-red time band.

9 Transmission connection (exit) charges for demand tariffs

9.1 A separate transmission exit charge is applied to demand tariffs.

9.2 A single charging rate, in p/kW/day is calculated as follows:

> Transmission exit charging rate p/kW/day = 100 / DC * NGET charge / (CDCM system maximum load + total EDCM peak time consumption) *
>
> Where:
>
> DC is the number of days in the charging year.
>
> NGET charge is the forecast annual DNO expenditure on transmission connection point charges in £.
>
> CDCM system maximum load is the forecast system simultaneous maximum load from CDCM users (in kW) from CDCM table 2506.
>
> Total EDCM peak time consumption (in kW) calculated by multiplying the maximum capacity of each user by the forecast peak-time kW divided by forecast maximum kVA of that user (adjusted for losses to transmission and, if necessary, for customers connected for part of the charging year) and aggregating across all EDCM demand.

9.3 The single £/kW/year charging rate is converted into a p/kVA/day import capacity based charge for each EDCM demand user as follows

Transmission exit charge p/kVA/day = [Transmission exit charging rate in £/kW/year] * [Forecast peak-time kW divided by kVA of that user, adjusted for transmission losses and, if necessary for customers connected part of the year]

10 Reactive power charges

10.1 The EDCM would not include a separate tariff component for any reactive power flows for demand.

11 Allocation drivers for other tariff elements in the EDCM

11.1 In addition to charges calculated using the FCP and LRIC methodologies and transmission connection (exit) charges, the EDCM includes tariff elements relating to:

- DNO direct operating costs (this includes inspection and maintenance costs, operating expenditure relating to fault repairs and the cost of tree cutting);
- DNO indirect costs. (these are costs that are not directly related to network assets, such as business support costs);
- DNO network rates (these are business rates paid by DNOs); and
- DNO residual revenue.

11.2 The residual revenue is that part of the DNO's allowed revenue that has not been pre-allocated to demand tariffs using cost-based tariff elements.

11.3 EDCM tariff elements are determined using allocation drivers. The following allocation drivers are used in the EDCM:

- The value of assets that are for the sole use of a customer (sole use assets).
- The value of site-specific shared network assets used by the customer.
- The sum of historical consumption at the time of system peak and 50 per cent of maximum import capacity.

11.4 The methods used to determine the value of sole use assets and shared site-specific shared network assets are described below.

12 Sole use assets

12.1 The value of a customer's sole use assets used is expressed in the form of a modern equivalent asset value (MEAV) in £.

12.2 Sole use assets are assets in which only the consumption or output associated with a single customer can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements, i.e. all assets between the customer's Entry/Exit Point(s) and the Distribution Point(s) of Common Coupling (DPCC) with the general network are considered as sole use assets.

12.3 The DPCC for a particular single customer is the point on the network where the power flow associated with the single customer under consideration, may under some (or all) possible arrangements interact with the power flows associated with other customers, taking into account all possible credible running arrangements.

12.4 Where a single site has two tariffs, associated with import and export meter registrations, the sole use assets are allocated between the import and export tariffs proportionally to maximum import and export capacities respectively.

12.5 Where an EDCM site was originally connected as a single customer, and has subsequently split into multiple sites, these sites continue to be considered as one site for the purposes of determining sole use assets. The sole use asset MEAV is allocated between these sites in proportion to their maximum import or export capacities.

13 Site-specific shared network assets

13.1 A customer’s notional site-specific shared network asset value is the value of network assets that are deemed to be used by that customer, other than sole use assets as defined earlier.

13.2 The value of notional site-specific shared assets used by each customer is expressed in the form of a modern equivalent asset value (MEAV) in £.

13.3 The value of shared network assets used by each demand user is calculated as set out below.

13.4 Five levels are defined for the network’s assets:

- Level 1 comprises 132 kV circuits.
- Level 2 comprises substations with a primary voltage of 132 kV and a secondary voltage of 22 kV or more.
- Level 3 comprises circuits of 22 kV or more but less than 132 kV.
- Level 4 comprises substations with a primary voltage of 22 kV or more but less than 132 kV and a secondary voltage of less than 22 kV.
- Level 5 comprises substations with a primary voltage of 132 kV and a secondary voltage of less than 22 kV.

13.5 In some cases, it might be appropriate to treat 66 kV equipment as being equivalent to 132 kV equipment and allocate customers to categories accordingly.

13.6 EDCM customers are split into 15 categories based on the parts of the EHV network they are deemed to use. This is based on the distribution point of common coupling, defined as the point at which the sole use assets meet the rest of the distribution network. The distribution point of common coupling might be at a different voltage than the customer's supply, and might also be at a different voltage than the voltage of connection when the customer was connected.

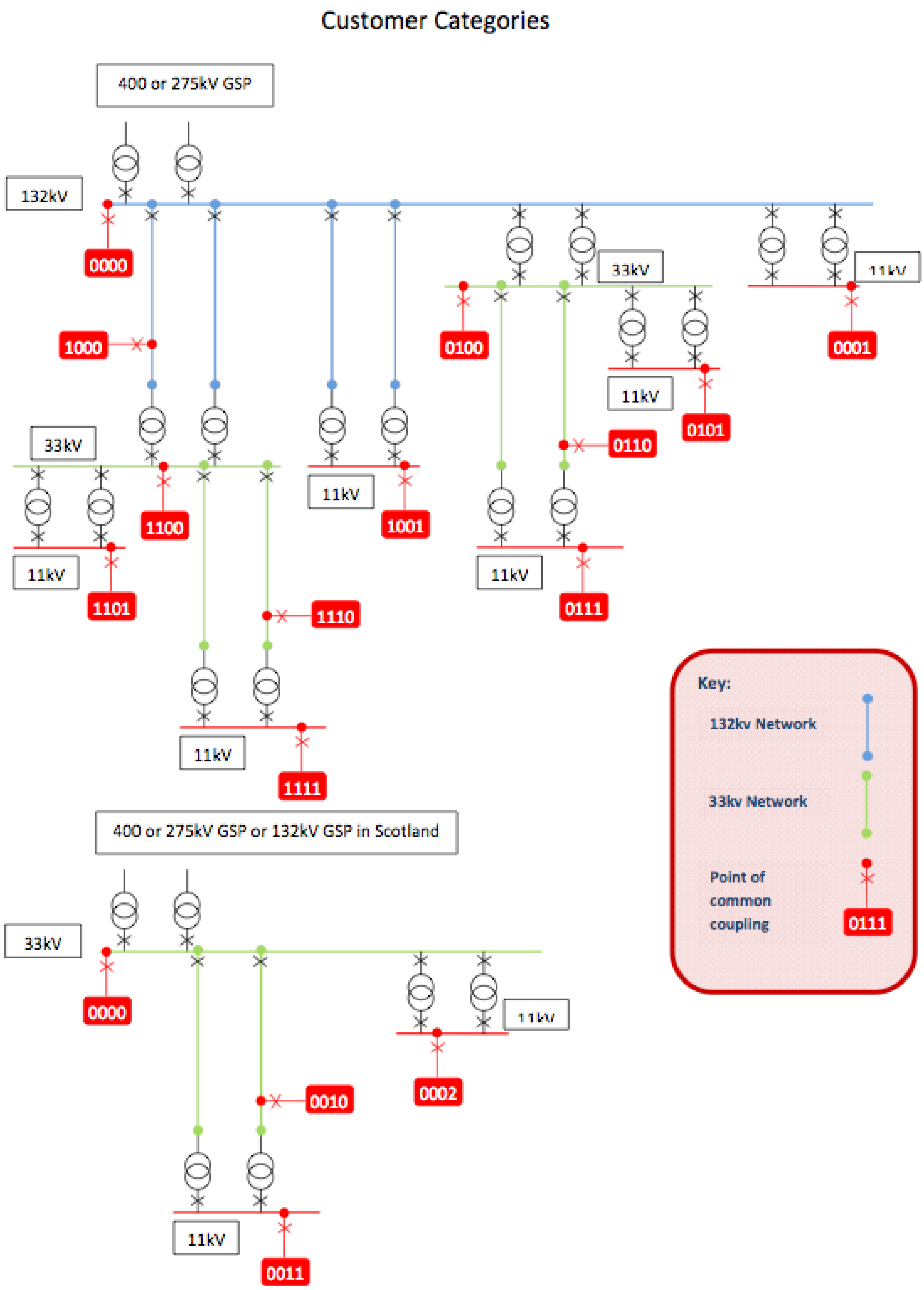
Table 2 Categorisation of EDCM customers

Category	Definition
Category 0000	Point of common coupling at the GSP, whether the GSP is shared or not.
Category 1000	In England or Wales only, point of common coupling at a voltage of 132 kV, unless the customer qualifies for category 0000.
Category 1100	Point of common coupling at 22 kV or more on the secondary side of a substation where the primary side is attached to a 132 kV circuit.
Category 0100	Point of common coupling at 22 kV or more, but less than 132 kV, on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 1110	Point of common coupling at a voltage of 22 kV or more, but less than 132 kV, not at a substation, fed from a substation whose primary side is attached to a 132 kV distribution circuit.
Category 0110	Point of common coupling at a voltage of 22 kV or more, but less than 132 kV, not at a substation, fed from a substation whose primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 0010	Point of common coupling at a voltage of 22 kV or more, but less than 132 kV, fed from a GSP with no intermediate transformation.
Category 0001	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no circuit.
Category 0002	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 22 kV or more but less than 132 kV, to a co-located GSP with no circuit.

Category 1001	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is attached to a 132 kV distribution circuit.
Category 0011	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from a GSP with no intermediate transformation.
Category 0111	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed through a distribution circuit from a substation whose primary side is attached at 132 kV to a co-located GSP with no circuit.
Category 0101	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from the secondary side of a co-located substation whose primary side is attached at 132 kV to a co-located GSP with no circuit.
Category 1101	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from the secondary side of a co-located substation whose primary side is attached to a 132 kV distribution circuit.
Category 1111	Point of common coupling at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed through a distribution circuit from a substation whose primary side is attached to a 132 kV distribution circuit.

13.7 All references to GSP in the table above relate to interconnections with the main interconnected onshore transmission network.

13.8 The figure overleaf provides examples of customers who might be placed in each of the categories described above.



13.9 The use of each network level by each EDCM demand customer is determined according the rules set out in the following table.

EDCM customers in category	**Level 1**	**Level 2**	**Level 3**	**Level 4**	**Level 5**
Category 0000	Zero	Zero	Zero	Zero	Zero
Category 1000	Capacity kVA	Zero	Zero	Zero	Zero
Category 1100	Peak-time active kW	Capacity kVA	Zero	Zero	Zero
Category 0100	Zero	Capacity kVA	Zero	Zero	Zero
Category 1110	Peak-time active kW	Peak-time active kW	Capacity kVA	Zero	Zero
Category 0110	Zero	Peak-time active kW	Capacity kVA	Zero	Zero
Category 0010	Zero	Zero	Capacity kVA	Zero	Zero
Category 0001	Zero	Zero	Zero	Zero	Capacity kVA
Category 0002	Zero	Zero	Zero	Capacity kVA	Zero
Category 1001	Peak-time active kW	Zero	Zero	Zero	Capacity kVA
Category 0011	Zero	Zero	Peak-time active kW	Capacity kVA	Zero
Category 0111	Zero	Peak-time active kW	Peak-time active kW	Capacity kVA	Zero
Category 0101	Zero	Peak-time active kW	Zero	Capacity kVA	Zero
Category 1101	Peak-time active kW	Peak-time active kW	Zero	Capacity kVA	Zero
Category 1111	Peak-time active kW	Peak-time active kW	Peak-time active kW	Capacity kVA	Zero

13.10 Category 0000 demand users are deemed not to use any network assets other than sole use assets.

13.11 An average network asset value per kVA (in £/kVA) is calculated in respect of each network level. The average network asset value for the network level of connection is based on the maximum capacity of the user, and for network levels above on consumption at peak time.

Average network asset value for capacity at level L (£/kVA) = NAR_L* AE /(1 + D_L)

Average network asset value for demand at level L (£/kVA) = NAR_L* D * LAF

Where:

NAR_L is the network asset rate at level L in £/kW based on the 500 MW model.

D_L is the diversity allowance from the level exit to the GSP group (from CDCM table 2611).

D is the peak time active power consumption in (kW/kVA). This is calculated as the historical peak-time kW divided by historical maximum kVA.

LAF is the loss adjustment factor to transmission from the CDCM for the network level relevant to the customer category of that customer. See table below for the correspondence between customer categories and network levels.

AE is the active power equivalent of capacity adjusted to transmission (in kW/kVA). This is calculated by multiplying the power factor in the 500 MW model by the loss adjustment factor to transmission for the network level relevant to that customer (as above).

Customer categories	**Relevant network level for loss adjustment factors**
0000	GSP (the loss adjustment factor is always 1 for this network level)
1000	132kV (level 1)
1100 and 0100	132kV/EHV (level 2)
1110, 0110 and 0010	EHV (level 3)
1111, 1101, 0101, 0111, 0011 and 0002	EHV/HV (level 4)
1001 and 0001	132kV/HV (level 5)

13.12 Again, separate site-specific asset values per kVA (in £/kVA) is calculated in respect of each network level. The asset value for the network level of connection is based on the maximum capacity of the user, and for network levels above on consumption at peak time.

Site-specific asset value for capacity at level L (£/kVA) = NU_L * Average network asset value for capacity at level L (£/kVA)

Notional asset value for demand at level L (£/kVA) = NU_L * Average network asset value for demand at level L (£/kVA)

Where:

NU_L is the network use factor for that user at level L, representing the proportion of the average 500 MW model assets that the user is deemed to use at that level. The methodology to calculate these network use factors is set out in Annex 2 of this document.

Average notional asset value for capacity at level L is the voltage level average calculated as described earlier.

Average notional asset value for demand at level L is the voltage level average calculated as described earlier.

13.13 Network use factors for import tariffs of a mixed import-export site that is generation-dominated are set to default values. These default values are equal to the "collars" for each network level calculated as described in section on demand scaling. DNOs implementing the FCP methodology would use the rules set out in the LRIC methodology to determine whether a location is to be modelled as a generation site, and is therefore generation dominated.

13.14 The total value of the site-specific shared assets required to serve each demand user is calculated according to the formula:

TNA = NAC + (NAD * (1 - (Hours in super-red for which not a customer/Annual hours in super-red))*(Days in year/(Days in year - Days for which not a customer)))

Where:

TNA is the total site-specific network assets in £/kVA required to serve a demand user.

NAC is the site-specific asset value in £/kVA for capacity for that demand user aggregated across all levels.

NAD is the site-specific asset value in £/kVA for demand for that demand user aggregated across all levels.

13.15 Total site-specific shared assets for all EDCM demand is the aggregate value (in £) of all site-specific shared assets for EDCM demand users. This is calculated by multiplying TNA by the maximum import capacity (adjusted, if necessary, for customers connected for part of the charging year), and then aggregating across all EDCM demand.

14 Calculation of the EDCM demand revenue target

14.1 The EDCM demand revenue target is the share of the DNO's allowed revenue (excluding transmission exit charges and net revenue from EDCM generation) that will be recovered from EDCM demand customers.

14.2 This section describes the method used to calculate the EDCM demand revenue target.

14.3 A single contribution rate for network rates is calculated for all EDCM demand users as follows:

Network rates contribution rate (per cent) = NR / (Total site-specific shared assets + Total EDCM sole use assets + EHV assets + HV and LV network assets + HV and LV service model assets)

Where:

NR is the total DNO expenditure on network rates.

Total site-specific shared assets is the aggregate value (in £) of all site-specific shared assets for EDCM demand users.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM demand users and non-CDCM generation users adjusted for part-year connected customers .

EHV assets are the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

HV and LV service model assets from the CDCM model.

14.4 A single contribution rate for direct operating costs is calculated for all EDCM demand users as follows:

Direct operating costs contribution rate (per cent) = DOC / (Total site-specific shared assets + Total EDCM sole use assets + EHV assets + (HV and LV network assets + HV and LV service model assets) / 0.68)

Where:

DOC is the total DNO expenditure on direct operating costs.

Total site-specific shared assets is the aggregate value (in £) of all site-specific shared assets for EDCM demand users.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM demand users and non-CDCM generation users adjusted for part-year connected customers .

EHV assets are the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

HV and LV service model assets from the CDCM model.

0.68 is the operating intensity factor.

14.5 A single contribution rate for indirect costs is calculated for all EDCM demand users as follows:

Indirect costs contribution rate (per cent) = INDOC / (Total site-specific shared assets + Total EDCM sole use assets + EHV assets + (HV and LV network assets + HV and LV service model assets) / 0.68)

Where:

INDOC is the total DNO expenditure on indirect costs.

Total site-specific shared assets is the aggregate value (in £) of all site-specific shared assets for EDCM demand users.

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM demand users and non-CDCM generation users adjusted for part-year connected customers .

EHV assets are the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

HV and LV service model assets from the CDCM model.

0.68 is the operating intensity factor.

14.6 Next, a residual revenue contribution rate is calculated as follows:

Residual revenue contribution rate (per cent) = (AR - DOC – INDOC – NR – GCN) / (Total site-specific shared assets + EHV assets + HV and LV network assets)

Where:

AR is the DNO total allowed revenue excluding transmission exit charges in £/year

DOC is the total DNO expenditure on direct operating costs.

INDOC is the total DNO expenditure on indirect costs.

NR is the total DNO expenditure on network rates.

GCN is the total forecast net revenue in £/year from the application of non-CDCM export tariffs. This amount is an input to the EDCM model and is calculated by the DNO outside the EDCM model.

Total site-specific shared assets is the aggregate value (in £) of all site-specific shared assets for EDCM demand users.

EHV assets are the aggregate EHV assets in the CDCM model.

HV and LV network assets from the CDCM model.

14.7 The contribution rates for network rates, direct costs, indirect costs and residual revenue is converted into a £/year import capacity based contribution and a sole use asset MEAV based contribution for each EDCM demand user.

Import capacity based network rates contribution for each user = TNA * NR rate * import capacity

Import capacity based direct operating costs contribution for each user = TNA * DOC rate * import capacity

Import capacity based indirect costs contribution for each user = TNA * INDOC rate * import capacity

Import capacity based residual revenue contribution for each user = TNA * residual revenue rate * import capacity

Where:

TNA is the total site-specific assets (£/kVA) for that demand user.

NR rate is the network rates contribution rate in per cent.

DOC rate is the direct operating costs contribution rate in per cent.

INDOC rate is the indirect costs contribution rate in per cent.

Residual revenue rate is the residual revenue contribution rate in per cent.

Import capacity is the maximum import capacity (adjusted, if necessary, if the customer is connected for part of the charging year) in kVA for that demand user

14.8 The sole use asset MEAV based contribution in £/year is calculated as follows:

Sole use asset based network rates contribution = S * NR rate

Sole use asset based direct operating costs contribution = S * DOC rate

Sole use asset based indirect costs contribution = S * INDOC rate

Where

S is the MEAV of sole use assets of that user (adjusted for customers connected for part of the charging year).

NR rate is the network rates contribution rate in per cent.

DOC rate is the direct operating costs contribution rate in per cent.

INDOC rate is the indirect costs contribution rate in per cent.

14.9 The target contributions from import capacity and sole use assets are aggregated across all EDCM demand users.

14.10 The aggregate EDCM demand revenue target is calculated as the sum, across all EDCM demand, of the contributions based on import capacities and sole use assets.

15 Demand scaling

15.1 Demand scaling is the process by which charges to EDCM demand customers are set so that the forecast notional recovery from demand customers matches the EDCM demand revenue target.

15.2 Demand scaling using the site-specific assets approach involves the following steps:

- Calculating adjusted site-specific shared asset values for each customer using network use factors that have been subjected to a cap and collar.

- Allocation of the direct operating cost and network rates elements in the EDCM demand revenue target to individual EDCM demand users on the basis of adjusted site-specific assets and sole use assets.

- Allocation of the indirect cost element in the EDCM demand revenue target to individual EDCM demand customers in the basis of their consumption at the time of DNO peak and 50 per cent of maximum import capacity as a p/kVA/day charge.

- Forecasting the notional recoveries from the application of FCP charges to EDCM demand users.

- Allocation of 80 per cent of the difference between the EDCM demand revenue target and the sum of charges under (a), (b) and (c) above on the basis of adjusted site-specific assets.

- Allocation of 20 per cent of the difference between the EDCM demand revenue target and the sum of charges under (a), (b) and (c) above on the basis of consumption at the time of peak and 50 per cent of maximum import capacity as a p/kVA/day fixed adder.

15.3 Adjusted site-specific assets are calculated using network use factor that have been subjected to caps and collars.

15.4 A cap and a collar are calculated for each network level as follows:

- In ascending order, list the network use factors for all demand users in all DNO areas relating to that network level, excluding all the factors that are either equal to zero or 1, or not used, based on the customer categories of each demand user.

- Divide the list into two segments, one that contains factors that are lower than 1, and the other than contains the factors that are higher than 1.

- Take the list segment containing factors that are lower than 1. Starting from the lowest factor in this list segment, calculate the factor at the 15th percentile. This is the collar.

- Take the list segment containing factors higher than 1. Starting from the lowest factor in this segment, calculate the factor at the 85th percentile. This is the cap.

15.5 The same cap and collar would apply in all DNO areas to NUFs at that network level.

15.6 The caps and collars for each network level calculated using this methodology is set out in table 3 below. Illustrative tariffs for 2011/2012 have been calculated using these values.

Table 3 Network use factor caps and collars

Network levels	Collar	Cap
132 kV	0.273	2.246
132kV/EHV	0.677	1.558
EHV	0.332	3.290
EHV/HV	0.631	2.380
132kV/HV	0.697	2.768

15.7 The caps and collars in the table above would be fixed for three years, and would be used to calculate tariffs for the charging years 2012/2013 and 2013/2014. The caps and collars would be re-calculated for the subsequent three charging years using the averages of the network use factors for each tariff for the previous three years.

15.8 Table 4 below sets out the schedule for the calculation of caps and collars for each charging year.

Table 4 NUF cap and collar calculation timeline

Charging Year	NUFs used create the cap and collar
2011/2012 Submission	2011/2012 NUFs
2012/2013	2011/2012 NUFs
2013/2014	2011/2012 NUFs
2014/2015	Average of 2011/2012, 2012/2013, 2013/2014 NUFs

2015/2016	Average of 2011/2012, 2012/2013, 2013/2014 NUFs
2016/2017	Average of 2011/2012, 2012/2013, 2013/2014 NUFs
2017/2018	Average of 2014/2015, 2015/2016, 2016/2017 NUFs
2018/2019	Average of 2014/2015, 2015/2016, 2016/2017 NUFs
2019/2020	Average of 2014/2015, 2015/2016, 2016/2017 NUFs
2020/2021	Average of 2017/2018, 2018/2019, 2019/2020 NUFs
2021/2022	Average of 2017/2018, 2018/2019, 2019/2020 NUFs
2022/2023	Average of 2017/2018, 2018/2019, 2019/2020 NUFs

15.9 Separate adjusted site-specific asset values per kVA (in £/kVA) is calculated in respect of each network level. The asset value for the network level of connection is based on the maximum capacity of the user, and for network levels above on consumption at peak time.

Adjusted site-specific asset value for capacity at level L (£/kVA) = NUa_L * Average network asset value for capacity at level L (£/kVA)

Adjusted site-specific asset value for demand at level L (£/kVA) = NUa_L * Average network asset value for demand at level L (£/kVA)

Where:

NUa_L is the adjusted network use factor for that user at level L after application of the cap and collar.

Average notional asset value for capacity at level L is the voltage level average calculated as described earlier.

Average notional asset value for demand at level L is the voltage level average calculated as described earlier.

15.10 The total value of the adjusted site-specific shared assets required to serve each demand user is calculated according to the formula:

TNAa = NACa + (NADa * (1 - (Hours in super-red for which not a customer/Annual hours in super-red))*(Days in year/(Days in year - Days for which not a customer)))

Where:

TNAa is the total adjusted site-specific network assets in £/kVA required to serve a demand user.

NACa is the adjusted site-specific asset value in £/kVA for capacity for that demand user aggregated across all levels.

NADa is the adjusted site-specific asset value in £/kVA for demand for that demand user aggregated across all levels.

15.11 Total adjusted site-specific shared assets for all EDCM demand is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM demand users. This is calculated by multiplying TNAa by the import capacity (adjusted, if necessary, for customers connected for part of the charging year), and then aggregating across all EDCM demand.

15.12 The direct cost and network rates allocations to individual demand customers is determined in the same way as the contributions to the EDCM demand revenue target was calculated, except that adjusted site-specific assets are used.

15.13 A single asset based charging rate for network rates is calculated for all EDCM users. This is calculated as follows:

Network rates charging rate (per cent) = EDCM NR contribution / (Total adjusted site-specific shared assets)

Where:

EDCM NR contribution is the sum of the import capacity based network rates contribution from each EDCM demand user.

Total adjusted site-specific shared assets is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM demand users.

15.14 A single asset based charging rate for direct operating costs is calculated for all EDCM users. This is calculated as follows:

Direct operating costs charging rate (per cent) = EDCM DOC contribution / (Total adjusted site-specific shared assets)

Where:

EDCM DOC contribution is the sum of the import capacity based direct costs contribution from each EDCM demand user.

Total adjusted site-specific assets is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM demand users.

15.15 The charging rates for network rates and direct operating costs are converted into p/kVA/day import capacity based charges for each EDCM demand user.

Network rates and direct costs charge in p/kVA/day = (100 / DC) * TNAa * (NR rate + DOC rate)

Where:

DC is the number of days in the charging year.

TNAa is the total adjusted site-specific assets (£/kVA) for that demand user.

NR rate is the network rates charge rate in per cent.

DOC rate is the direct operating costs charge rate in per cent.

15.16 The charging rates for network rates and direct operating costs are converted into a p/day fixed charge for the sole use assets of each EDCM demand user as follows:

Fixed charge on sole use assets in p/day = 100 / DC * S * (NR contribution rate + DOC contribution rate)

Where

DC is the number of days in the charging year.

S is the MEAV of sole use assets of that user.

NR contribution rate is the network rates contribution rate in per cent.

DOC contribution rate is the direct operating costs contribution rate in per cent.

15.17 A p/kVA/day charging rate for indirect costs for each EDCM demand customer is calculated on the basis of historical demand at the time of DNO peak and 50 per cent of maximum import capacity of that customer.

Indirect cost charging rate in p/kVA/day = 100 / DC * (Aggregate indirect cost contribution) / Volume for scaling

Where:

DC is the number of days in the charging year.

Volume for scaling is calculated as the sum of (0.5 + coincidence factor)* import capacity * LDNO factor across all demand tariffs.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by maximum capacity in kVA of that customer (based on historical data) multiplied by (1 - (Hours in super-red for which not a customer/Annual hours in super-red))*(Days in year/(Days in year - Days for which not a customer))

Import capacity is the maximum import capacity (adjusted if the customer is connected for part of the charging year) in kVA for that demand user.

LDNO factor takes the value 0.5 if the demand user is connected to an LDNO and 1 otherwise.

Aggregate indirect cost contribution is the sum of the import capacity based and sole use asset based indirect cost contribution from each EDCM demand user.

15.18 The p/kVA/day charging rate for indirect costs is converted into an import capacity based charge for each demand user as follows:

Import capacity based INDOC charge in p/kVA/day = Indirect cost charging rate * (0.5 + coincidence factor) * LDNO factor

Where:

Indirect cost charging rate is the DNO-wide p/kVA/day rate calculated as described in the previous paragraph.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by maximum capacity in kVA of that customer (based on historical data) multiplied by (1 - (Hours in super-red for which not a customer/Annual hours in super-red))*(Days in year/(Days in year - Days for which not a customer))

LDNO factor takes the value 0.5 if the demand user is connected to an LDNO and 1 otherwise.

15.19 A single asset based residual revenue charging rate is calculated for all EDCM demand users. This is calculated as follows:

Residual revenue charging rate (per cent) = 0.8 * (EDCM demand revenue target – EDCM NR and DOC capacity contribution - Aggregate indirect cost contribution – SU recovery - FCP/LRIC recovery) / Total adjusted site-specific shared assets

Where:

EDCM NR and DOC capacity contribution is the sum of the import capacity based network rates and direct costs contribution from each EDCM demand user.

Aggregate indirect cost contribution is the sum of the import capacity based and sole use asset based indirect cost contribution from each EDCM demand user.

SU recovery is the forecast notional recovery from the application of fixed charges for sole use assets relating to EDCM demand customers.

Total adjusted site-specific shared assets is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM demand users.

15.20 The asset based charging rate for residual revenue is converted into a p/kVA/day import capacity based residual revenue charge for each EDCM demand user.

Asset based residual revenue charges in p/kVA/day = (100 / DC) * TNAa * Residual revenue rate

Where:

DC is the number of days in the charging year.

TNA is the total site-specific assets (£/kVA) for that demand user.

Residual revenue rate is the residual revenue charging rate in per cent.

15.21 A fixed adder in p/kVA/day for the remaining 20 per cent of residual revenue is calculated as follows:

Single fixed adder in p/kVA/day = 100 / DC * 0.2 * (EDCM demand revenue target – EDCM NR and DOC capacity contribution - Aggregate indirect cost contribution - SU recovery - FCP/LRIC recovery) / Volume for scaling

Where:

DC is the number of days in the charging year.

EDCM demand target is the EDCM demand revenue target calculated as described in the previous section.

EDCM NR and DOC capacity contribution is the sum of the import capacity based direct costs contribution from each EDCM demand user (from annex 3).

Aggregate indirect cost contribution is the sum of the import capacity based and sole use asset based indirect cost contribution from each EDCM demand user

SU recovery is the forecast notional recovery from the application of fixed charges for sole use assets relating to EDCM demand customers.

FCP recovery is the forecast notional recovery from the application of FCP charges to all EDCM demand users only.

Volume for scaling is calculated as the sum of (0.5 + coincidence factor)* import capacity.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by maximum capacity in kVA of that customer (based on historical data) multiplied by (1 - (Hours in super-red for which not a customer/Annual hours in super-red))*(Days in year/(Days in year - Days for which not a customer))

Import capacity is the maximum import capacity (adjusted if the customer is connected for part of the charging year) in kVA for that demand user.

15.22 The fixed adder in p/kVA/day is converted into an import capacity based charge for each demand user as follows:

Import capacity based fixed adder in p/kVA/day = Fixed adder * (0.5 + coincidence factor)

Where:

Fixed adder is the DNO-wide p/kVA/day fixed adder calculated as described in the previous paragraph.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by maximum capacity in kVA of that customer (based on historical data) multiplied by (1 - (Hours in super-red for which not a customer/Annual hours in super-red))*(Days in year/(Days in year - Days for which not a customer)).

16 Application of EDCM tariffs for end users

16.1 The tariff application rules for the EDCM are the same as for the CDCM wherever possible.

16.2 The part of EDCM portfolio tariffs (for LDNOs and exempt networks) that is based on CDCM tariffs will be billed like CDCM tariffs.

16.3 Final EDCM demand tariffs will have:

1) a fixed charge on sole use assets (in p/day)
2) an import capacity charge in (p/kVA/day)
3) a super-red unit rate charge (in p/kWh)
4) an exceeded capacity charge (in p/kVA/day).

16.4 The fixed charge on sole use assets in p/day is applied to each EDCM demand tariff.

16.5 The final EDCM capacity charge for each demand tariff in p/kVA/day would be calculated as follows:

EDCM import capacity charge (p/kVA/day) = [FCP p/kVA/day capacity charge] +[Transmission exit charge p/kVA/day] + [Network rates and direct costs charge in p/kVA/day] + [Indirect costs charge in p/kVA/day] + [Asset based residual revenue charges in p/kVA/day] + [Single fixed adder in p/kVA/day]

16.6 The final EDCM super-red unit rate in p/kWh is the FCP super-red unit rate as calculated as described earlier in this document.

16.7 If the EDCM import capacity charge (p/kVA/day) calculated above is negative and the customer's average kW/kVA is not equal to zero, the final EDCM super-red unit rate is adjusted as follows:

Adjusted FCP super-red unit rate in p/kWh = [FCP super-red rate in p/kWh] + ([EDCM import capacity charge (p/kVA/day)] * ([Days in the charging year] – [Days for which not a customer]) / [Average kW/kVA] / ([hours in the super-red time band] - [Hours in super-red for which not a customer]))

16.8 Finally, any remaining negative super-red unit rates or import capacity charges are set to zero.

17 Exceeded capacity charges

17.1 Where a customer uses additional capacity over and above the maximum import capacity without authorisation, the excess is classed as exceeded capacity.

17.2 For the purposes of determining capacity used, the following formula is used for each half hour:

Import capacity used = 2 * (SQRT(AI^2 + MAX(RI,RE)^2))

Where:

AI = Import consumption in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

17.3 For the purposes of calculating exceeded capacity for import tariffs, any reactive flows during half hours when there is no active power import would not be taken into account.

17.4 Any reactive flows associated with a site which operates subject to grid code requirements for generation or sites providing voltage control at the request of the DNO would not be taken into account when calculating capacity used.

17.5 For most customers, the exceeded portion of the capacity is charged at the same rate as the capacity that is within the maximum. This is charged for the duration of the month in which the breach occurs.

17.6 Sites subject to DSM arrangements would normally pay the DSM-adjusted capacity charge for capacity usage up to their maximum import capacities.

17.7 If such sites were to exceed their maximum import or export capacities, the exceeded portion of the capacity will be charged at a different rate. This will be charged for the duration of the month in which the breach occurs. This charge for exceeded capacity (in p/kVA/day) would be determined as follows;

[Exceeded capacity charge in p/kVA/day] = [Import capacity charge p/kVA/day] + (([FCP capacity charge p/kVA/day] + ([FCP super-red rate p/kWh] * [Average kW/kVA adjusted for part year] * [number of super-red hours connected] / ([days in charging year] – [Days for which not a customer]))) * (1 - ([chargeable capacity]/ [maximum import capacity]))

Where:

The FCP super-red unit rate and FCP capacity charges in the equation above are the charges before any adjustments for DSM have been made.

18 Application of tariff components

18.1 Table 5 summarises the method of application of tariff components for demand.

Table 5 Application of tariff components for import (demand) tariffs

Tariff component	Unit	Application
Fixed charge	p/day	Applied as a fixed charge.
Import capacity charge	p/kVA/day	Applied to the maximum import capacity.
Exceeded import capacity charge	p/kVA/day	Applied to exceeded capacity for the duration of the month in which the breach occurs (except for sites which operates subject to grid code requirements for generation)
Super-red unit rate	p/kWh	Applied to units consumed during the DNO's super-red time band.

19 Tariffs for new customers

19.1 New customers could connect at any time between the publication of EDCM tariffs for the new charging year and the end of that charging year.

19.2 If the connection of such customers had been anticipated before the publication of charges, DNOs would have included forecast data relating to the new customer in both the power flow model and the EDCM tariff model. The resulting tariff is applied to the new customer, on a pro-rata basis if the price is produced during the charging year.

19.3 If prices need to be produced for new connections that had not been anticipated at the time of calculating EDCM charges for that charging year, the DNO party will:

- Seek indicative load profile information from the new customer, failing that, make a reasonable estimate;
- Run the power flow model after including the new customer to produce a full set of charges 1 and 2, including for the new customer;
- Include the new customer's details, including marginal charges from (a) in the EDCM tariff model, to produce a full set of new tariffs;
- Use the tariff relating to the new customer to calculate charges; and
- Charges relating to the current year for existing customers would not change as a result.

19.4 If a customer were to change their maximum import or export capacity at any time between the publication of EDCM tariffs for the charging year and the end of the charging year, the published tariff rates would continue to apply for the duration of the charging year.

20 DNO to DNO tariffs

20.1 In the case of DNO to DNO interconnections, the interconnections are categorised into four types:

a) The interconnector between the DNOs is normally closed (active), and there is an identifiable benefit from the existence of the interconnection to one DNO only. The other DNO does not benefit from the interconnection.

b) The interconnector is normally closed (active), and there is either an identifiable benefit to both DNOs, or no clear benefit to either DNO.

c) The interconnector is normally open, and the interconnection exists only to provide backup under certain conditions to either DNO.

d) All other interconnections between DNOs.

20.2 In all cases of type (a), the benefitting DNO will be treated as being equivalent to an EDCM user connected to the other DNO's network. The DNO providing the benefit will calculate and apply an EDCM demand tariff as applicable to the other DNO. Sole use asset charges will not apply.

20.3 In the case of type (b) interconnections, each DNO will treat the other as an EDCM demand customer. Normal EDCM demand user charges, except charges for sole use assets, will apply.

20.4 Type (c) interconnections are typically covered by special arrangements between DNOs. Use of system charges are agreed between DNOs and applied outside the EDCM model.

20.5 In every other case, each DNO charges the other as a normal EDCM demand customer, as with type (b) interconnections.

21 LDNO charging

21.1 LDNOs with distribution systems that serve end users that fall within the scope of the CDCM would have their charges based on standard discount percentages applied to the CDCM all-the-way end user tariffs.

An LDNO with distribution systems that qualifies as a CDCM "Designated Property" according to the definition set out in licence condition 50.10 are eligible for portfolio discounts calculated using a price control disaggregation model (method M) consistent with the CDCM methodology set out in the distribution connection and use of system agreement (DCUSA).

An LDNO with distribution systems that qualifies as an EDCM "Designated EHV Property" according to the definition set out in the licence condition 50A.11 are eligible for discounts calculated using an "extended" price control disaggregation model (extended method M).

21.2 LDNOs with distribution systems that qualify as an EDCM "Designated EHV Property" could themselves have end users who would fall under the scope of the EDCM. Since the EDCM is a locational charging method, the host DNO would calculate EDCM tariffs at the DNO boundary for each EDCM-like end user on the LDNO's network. No discounts are calculated for such users as the DNO charges are based only on the specific site's equivalent use of the DNO network.

21.3 Under the EDCM, the DNO's network is divided into five network levels:

Level 1 comprises 132 kV circuits

Level 2 comprises substations with a primary voltage of 132 kV and a secondary voltage of 22 kV or more.

Level 3 comprises circuits of 22 kV or more, excluding circuits already categorised as being in Level 1.

Level 4 comprises substations with a primary voltage of 22 kV or more but less than 132 kV and a secondary voltage of less than 22 kV.

Level 5 comprises substations with a primary voltage of 132 kV and a secondary voltage of less than 22 kV.

21.4 DNOs may designate 66 kV circuits belonging to either network level 1 or 3 and substations with a primary voltage of 66 kV into level 2 or level 4 or level 5, depending on their network planning policies.

21.5 The network level of the boundary between the host DNO and the LDNO distribution system is determined by reference to the asset ownership boundary between the host DNO and the LDNO.

21.6 Where the LDNO distribution system only has one end user (whether a designated EHV property or not), the network level of the boundary between the host DNO and LDNO is determined by reference to the distribution point of common coupling (DPCC). The DPCC is determined in the same way as it is for an EDCM demand customer connected directly to the host DNO's network.

21.7 For EDCM demand customers, the distribution point of common coupling is the point on the network where the power flow associated with the single customer under consideration, may under some (or all) possible arrangements interact with the power flows associated with other customers, taking into account all possible credible running arrangements.

21.8 LDNO distribution systems are split into 15 categories based on the network level of the boundary between the host DNO and the LDNO, and whether or not higher network levels are used by the LDNO.

Table 6 Categorisation of designated EHV LDNOs

Category	Definition
Category 0000	Boundary at the GSP, whether the GSP is shared or not, with no use of any circuits.
Category 1000	In England or Wales only, boundary at a voltage of 132 kV, unless the customer qualifies for category 0000.
Category 1100	Boundary at 22 kV or more on the secondary side of a substation where the primary side is attached to a 132 kV circuit.
Category 0100	Boundary at 22 kV or more, but less than 132 kV, on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 1110	Boundary at a voltage of 22 kV or more, but less than 132 kV, not at a substation, fed from a substation whose primary side is attached to a 132 kV distribution circuit.
Category 0110	Boundary at a voltage of 22 kV or more, but less than 132 kV, not at a substation, fed from a substation whose primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 0010	Boundary at a voltage of 22 kV or more, but less than 132 kV, fed from a GSP with no intermediate transformation and no use of any 132 kV circuits.
Category 0001	Boundary at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.

Category 0002	Boundary at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 22 kV or more but less than 132 kV, to a co-located GSP with no use of any 132 kV circuits.
Category 1001	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is attached to a 132 kV distribution circuit.
Category 0011	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from a GSP with no intermediate transformation and no use of any 132 kV circuits.
Category 0111	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed through a distribution circuit from a substation whose primary side is attached at 132 kV to a co-located GSP with no use of any 132 kV circuits.
Category 0101	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed from the secondary side of a co-located substation whose primary side is attached at 132 kV to a co-located GSP with no use of any circuit.
Category 1101	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more but less than 132 kV, with no use of 33 kV circuit, fed from the secondary side of a co-located substation whose primary side is attached to a 132 kV distribution circuit.
Category 1111	Boundary at a voltage of less than 22 kV on the secondary side of a substation whose primary side is at a voltage of 22 kV or more, but less than 132 kV, fed through a distribution circuit from a substation whose primary side is attached to a 132 kV distribution circuit.

21.9 All references to GSP in the table above relate to interconnections with the main interconnected onshore transmission network.

22 The extended "Method M" model

22.1 The extended price control disaggregation model (the extended method M model) calculates discount percentages in a two-part process.

22.2 For the purposes of the first part of the process, the DNO's network is split into four levels: LV, HV/LV, HV and EHV.

22.3 The first part of the price control disaggregation involves the calculation of separate percentages by network level of each element of the DNO's price control allowed revenue: the operating cost, depreciation and return on RAV elements. These are aggregated over the period 2005/2006 to 2009/2010 (the DPCR4 period).

22.4 In order to determine the allocation to network levels of each element of price control revenue, the following cost allocation drivers are used:

- Data submitted by the DNOs to Ofgem using the format prescribed in the regulatory reporting pack (RRP) on units distributed and operating expenditure broken down by network level (typically relating to the year 2007/2008).

- Data that each DNO considers appropriately represents the forecast of net capital expenditure and customer contributions for the period 2005/06–2014/15, broken down by network level.

- Forecast data that each DNO considers appropriately represents the gross modern equivalent asset values (replacement costs) for various asset types.

22.5 Data from the RRP are used to distinguish between direct and indirect costs, with direct costs coded by network level. For the purpose of this calculation, capital expenditure is included, net of customer contributions, but negative figures are replaced with zero. This analysis provides direct costs percentage for each network level.

22.6 Indirect operating costs are allocated to network levels on the basis of an estimate of MEAV by network level.

22.7 The operating cost percentage for each level is a weighted average of the direct and indirect percentages. Estimated gross modern equivalent asset values used for this purpose are derived from asset counts and unit costs DNO forecasts wherever available. Transmission exit charges are excluded from the allocation because it does not seem reasonable to allocate these charges to different network levels.

22.8 Both the depreciation and return on capital elements of allowed revenue are allocated to network levels on the basis of net capital expenditure data derived from DNO estimates and forecasts. All figures are aggregated over the 10-year period from 2005/2006 to 2014/2015, taking in actual data or forecasts for each year as available.

22.9 For each network level, the relevant net capital expenditure is calculated by adding up total condition based replacement (proactive and reactive) replacement, combined in the case of LV, HV and EHV with connections spend minus customer contributions for connections at that voltage level, general reinforcement capital expenditure at that voltage level, and fault reinforcement capital expenditure at that voltage level.

22.10 Some of these categories allow HV substation and transformer costs to be identified. These costs (and no other costs) are allocated to the HV/LV network level. Some of the expenditure categories do not separately identify HV substation/transformer costs. For these categories costs are allocated to the HV/LV in the same proportion as for the other categories (where these costs are separately identified).

22.11 Generation-related capital expenditure is not included in the net capex attributable to each network level.

22.12 The allocation to each network level of each element of the DNO's price control allowed revenue is then aggregated by network level to create network level totals. These totals are then converted into network level percentages.

22.13 The network level percentages are used to allocate the DNO's allowed revenue less the net amount earned or lost by the licensee under price control financial incentive schemes less the total DNO transmission exit charges. All three numbers relate to a single year (typically 2007/2008).

22.14 The allowed revenue allocations are then rescaled by the estimated number of units flowing through each network level, and normalised so that they sum to 100 per cent. The net amount earned or lost by the licensee under price control financial incentive schemes plus the total DNO transmission exit charges (the unallocated part of the allowed revenue) is rescaled by the number of units flowing through the EHV network level. The result of this calculation is a set of percentages for each of the LV, HV/LV, HV and EHV network levels, and one percentage for the unallocated DNO revenue.

22.15 The second part of the price control disaggregation process is to split the percentage for the EHV network level in the above calculation into separate percentages for the following asset levels:

- 132 kV circuits (England and Wales only);
- 132kV/33kV substations (England and Wales only);
- 33 kV circuits; and
- 33kV/HV substations

22.16 For the purposes of calculating portfolio discounts for users that fall within the scope of the

CDCM, the 15 boundary categories between the DNO and the LDNO are grouped into five discount categories in England and Wales and three in Scotland:

a) Discount category 0000 - This applies to LDNO category 0000.

b) Discount category 132kV (in England and Wales only) - This applies to LDNO category 1000.

c) Discount category 132kV/EHV (in England and Wales only) - This applies to LDNO categories 1100 and 0100.

d) Discount category EHV - This applies to LDNO categories 1110, 0110 and 0010.

e) Discount category HVplus - This applies to LDNO categories 1111, 0001, 1001, 0002, 0011, 0111, 1101, 0101.

22.17 For each combination of an end user network level and a discount category, the relevant discount for demand end users is calculated as follows:

For discount categories 0000, 132kV/EHV and HVplus

Discount percentage = P / (S + U)

For discount category 132kV

Discount percentage = (P + ([percentage for 132kV] * (1 – ([network length split for 132kV] * [direct cost proportion])))) / (S +U)

For discount category EHV

Discount percentage = (P + ([percentage for EHV] * (1 – ([network length split for EHV] * [direct cost proportion])))) / (S +U)

Where:

Discount percentage is the discount applicable for each combination of discount and end user type.

P is the sum of the percentages for all network levels below the network level of the LDNO-DNO boundary up to and including the network level of the end user.

S the sum of the percentages for all network levels in the distribution network above and including the network level of the end user

U is the ratio of the sum of the DNO's total incentive revenue and the transmission exit charge, and the DNO's total allowed revenue including any incentive revenue and transmission exit charge.

Network length split is equal to 1 minus the ratio of the average length of circuits on relevant network level (EHV or 132kV) that is deemed to be provided by the LDNO to that provided by the host DNO. The values for the "network length split" for 132kV and EHV are currently set to 100 per cent.

Direct cost proportion is the percentage share of direct costs in the sum of direct costs and indirect costs (excluding IT and telecoms and property management costs) at EHV. Negative costs will be excluded from the calculation.

22.18 Whereas demand tariffs reflect costs at the network level of supply and at every level above that, generation tariffs only reflect costs above the network level of supply. For example, credits to HV generators do not include anything based on the costs of HV networks.

22.19 In each case, the discount is applied to all CDCM tariff components. Discount percentages are capped to 100 per cent.

23 Portfolio EDCM tariffs for end users in the EDCM

23.1 For end users on a LDNO's distribution system that would be covered by the EDCM if they were on the DNO's network, the EDCM methodology is applied to calculate a portfolio EDCM charge/credit for each such end user.

23.2 These EDCM portfolio tariffs would be calculated as if each EDCM end user on the LDNO's distribution system were notionally connected at the boundary between the DNO and LDNO.

23.3 For the purposes of calculating the boundary-equivalent portfolio EDCM tariffs, each EDCM end user on the LDNO's network would be assigned the demand customer category relating to the 15 LDNO boundary categories.

23.4 Such end users would attract charges (credits) in respect of any reinforcements caused (avoided) on the DNO's network only, i.e. any network branches that are on the LDNO's network would be attributed a zero FCP charge/credit.

23.5 The setting of final charges to embedded Designated EHV Properties including the calculation of charges for assets used on the embedded network will be established by the LDNO.

23.6 All EDCM charges would be calculated using "boundary equivalent" data provided by the LDNO to the host DNO for each embedded Designated EHV Property. For the purposes of the EDCM, boundary equivalent data should be what the LDNO has allowed for at the DNO-LDNO boundary, for each EDCM end user, after taking into consideration the diversity and losses within the LDNO's network. Data relating to CDCM end users must be considered for the purposes of calculating boundary equivalent data in order to cater for the effect of diversity and losses.

23.7 The EDCM will include in the tariffs for embedded Designated EHV Properties a fixed charge relating to any assets on the DNO's network that are for the sole use of an embedded LDNO network. These fixed charges would be calculated in the same way as it would be for EDCM customers connected directly to the host DNO's network.

23.8 In calculating charges for assets on the DNO's network that are for the sole use of an embedded LDNO distribution system, DNOs will charge only for the proportion of sole use assets deemed to be used by embedded Designated EHV Properties. This proportion will be calculated, in respect of each embedded Designated EHV Properties, as the ratio of the boundary equivalent capacity of that end user to the capacity at the LDNO/DNO boundary.

23.9 If there are no embedded Designated EHV Properties on the LDNO's network, no sole use asset charges would apply.

23.10 Demand scaling would be applied as normal to any EDCM portfolio tariff in respect of a demand user. For the purposes of scaling, all EDCM demand end users connected to the LDNO's network will be treated as notional EDCM demand end users connected to the DNO's network at the voltage level of the boundary.

23.11 For EDCM demand end users connected to the LDNO's network, the capacity-based charge for the DNO's indirect costs would be scaled down by a factor of 50 per cent.

24 Offshore networks charging

24.1 DNOs will treat offshore networks connected to the DNO as if they were EDCM end users.

24.2 The DNO will apply the EDCM to calculate an import and export charge based on capacity at the boundary and power flow data metered at the boundary.

24.3 Any sole use assets specific to the offshore network are charged as a p/day sole use asset charge calculated as applicable to a normal EDCM user.

24.4 Demand scaling will also be applied.

25 DNO to unlicensed networks

25.1 Unlicensed networks have a choice. If they are part of the Total System under the Balancing and Settlement Code with the network open to supply competition, and if they are party to the DCUSA, and have accepted the obligations to provide the necessary data, they can, if they wish, be treated as LDNOs.

25.2 Otherwise, the DNO applies the EDCM to calculate an import charge based on capacity and power flow data metered at the boundary. Any sole use assets specific to the unlicensed network are charged as a p/day sole use asset charge calculated as applicable to a normal EDCM user.

26 Derivation of 'Network Use Factors'

Step 1:

26.1 Powerflow analysis is used to determine the change in powerflow in each branch (in MW) that is caused by a change in load (in MW) at each node in the EHV network model, that represents either an EDCM demand customer or CDCM demand at the EHV/HV boundary.

26.2 In essence, a change in load of X MW is applied at the node under consideration and changes in powerflow in each network branch are identified. If the change in powerflow in a particular branch is Y MW, as a result in the change in load at the node under consideration, then the 'Change In Branch Flow per Change In Demand' is given by:-

Abs (Y/X) (MW branch flow per MW of demand at node)

26.3 The effects of a change in demand at each node, upon the powerflows in branches, are evaluated for each node in turn.

26.4 The method of evaluating the 'Change in Branch Flow per Change in Demand' shall be the Incremental Method, described below:

27 Incremental Method:

27.1 Establish the 'base case' powerflow in each branch using a network model constructed with demand data used to represent the Maximum Demand Scenario analysed in the marginal cost calculation, using Maximum Demand Data that represents the regulatory year that use of system charges are being calculated for.

27.2 Apply a 0.1MW (at 0.95 lagging p.f.) increment to each node, in turn, in the EHV network model (at nodes that represent either an EDCM demand customer or CDCM demand at the EHV/HV boundary) and identify the change in powerflow (in MW) in all branches where the change exceeds both 1kVA and 0.01% of the 'base case' powerflow in the branch. The change in branch flow corresponding to a 0.1MW increment at a node can be evaluated by actual application of an increment to the network model, or through the use of sensitivity coefficients. Prior to the application of the increment all the transformer tap positions, distributed generation outputs and switched shunt values are fixed to the values determined in the 'base case' powerflow to prevent change in their values when analysing the power flows with the increment applied.

27.3 This calculation is performed upon the Authorised Network Model and only considers normal running arrangements.

Step 2:

27.4 The 'MW usage' of each branch by a given nodal demand is determined by multiplying the relevant value of 'Change In Branch Flow per Change In Demand' (derived in step 1) by the demand at the node (MW) as used in the Maximum Demand Scenario for the marginal cost calculation, using the Maximum Demand Data that represents the regulatory year that use of system charges are being calculated for. This will always be a positive quantity.

Step 3:

27.5 For each branch, the 'total MW usage' of the branch by all nodal demands is determined by summating the 'MW usage of the branch' by each node (as determined in step 2).

Step 4:

27.6 Each nodal demand's proportionate usage of a branch is determined as the ratio of 'MW usage' of the branch by the nodal demand to the 'total MW usage' of the branch. This ratio is multiplied by the annuitised MEAV of the branch to create a £/ annum usage of the branch by the particular node.

27.7 Sole use assets are not to be included in the calculation of the MEAV of the branches and consequently some branches may have an MEAV of zero.

Step 5:

27.8 For each node, the £/annum 'usage' of branches (calculated in Step 4) of the same voltage level, by the demand at the node, are summated to create a total £/annum for each voltage level for the nodal demand. The considered voltage levels correspond to those used in the CDCM and include voltage levels that represent transformation between two voltages. These voltage levels are '132kV', '132kV/EHV', 'EHV', 'EHV/HV' and '132kV/HV'.

27.9 For each node where EDCM demand is present, the total £/annum 'usage' of branches of each voltage level, for the node, is divided by the demand at the node (in kW), as used in the

Maximum Demand Scenario, to create a £/kW/annum total usage of branches at each voltage level by the particular node. This shall be the numerator in the network use factor, for a particular voltage level, for the EDCM demand node.

27.10 For all nodes where CDCM demand is present, and the CDCM demand is considered to be 'dominant' at the node (CDCM demand shall be considered to be 'dominant' where the DNO estimates that the maximum demand associated with all CDCM demand at the node exceeds the maximum demand associated with all EDCM demand at the node), the £/annum 'usages' of branches at each voltage level (calculated in Step 4) are summated to create a total £/annum 'usage' for all CDCM dominated nodes. The CDCM demand 'using' each voltage level is determined by summating the nodal demands of all CDCM dominated nodes that have non zero £/annum 'usages' at the particular voltage level. The average £/kW/annum network usage by CDCM dominated nodes is derived for each voltage level by dividing the total £/annum usage (at the voltage level by CDCM dominated nodes) by the total CDCM demand 'using' the voltage level. This provides the denominators used for the network use factors.

27.11 The network use factor, at each voltage level, for each node where EDCM demand is present therefore is the £/kW/annum for the nodal demand at the appropriate voltage level, divided by the corresponding average £/kW/annum for the same voltage level determined for CDCM dominated nodes.

Glossary

Term	Explanation
Allowed Revenue	The amount of money that a network company can earn on its regulated business.
CDCM	The common distribution charging methodology. (The average charging model used for setting charges for high-voltage and low-voltage connections.)
Charging year	The financial year (12 month period ending on a 31st March) for which charges and credits are being calculated.
DCUSA	The Distribution Connection and Use of System Agreement.
Diversity allowance	The extent, expressed as a percentage, to which the sum of the maximum load across all assets in the modelled network level is expected to exceed the simultaneous maximum load for the network level as a whole.
EDCM	One of the distribution charging methodologies (FCP or LRIC) for higher voltage users specified in Ofgem's 31 July 2009 document.
EHV	In this document, EHV normally refers to nominal voltages of at least 22kV.
Embedded network	An embedded distribution network operated by an LDNO.
FBPQ	Forecast business plan questionnaire, a dataset produced by each regional distribution network operator for Ofgem as part of the price control review.
GSP	Grid supply point: where the distribution network is connected to a transmission network, except an offshore transmission network.
HV	Nominal voltages of at least 1kV and less than 22kV.
kV	Kilovolt (1,000 Volts): a unit of voltage.
kVA	Kilo Volt Ampere: a unit of network capacity.
kVAr	Kilo Volt Ampere reactive: a unit of reactive power flow. The network capacity used by a flow of A kW and B kVAr is SQRT(A^2+B^2) kVA.
kVArh	kVA reactive hour: a unit of total reactive power flow over a period of time. Reactive power meters usually register kVArh.
kW	Kilowatt (1,000 Watts): a unit of power flow.
kWh	Kilowatt hour: a unit of energy. Meters usually register kWh.

Term	Explanation
LDNO	Licensed distribution network operator. This refers to an independent distribution network operator (IDNO) or to a distribution network operator (DNO) operating embedded distribution network outside its distribution service area.
Licensee	The distribution network operator using this methodology to set use of system charges for its network.
LV	Nominal voltages of less than 1kV.
MVA	Mega Volt Ampere (1,000 kVA): a unit of network capacity.
MW	Megawatt (1,000 kW): a unit of power flow.
MWh	Megawatt hour (1,000 kWh): a unit of energy. Energy trading is usually conducted in MWh.
Network level	The network is modelled as a stack of circuit and transformation levels between supplies at LV and the transmission network. A network level is any circuit or transformation level in that stack. An additional network level is used for transmission exit.
Ofgem's 1 October 2008 document	"Delivering the electricity distribution structure of charges project", Ofgem, 1 October 2008, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.
Ofgem's 20 March 2009 document	"Next steps in delivering the electricity distribution structure of charges project", Ofgem, 20 March 2009, available from http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/.
Ofgem's 31 July 2009 document	"Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements", Ofgem, 31 July 2009.
Power factor	The ratio of energy transported (kW) to network capacity used (kVA).
Portfolio tariff	A tariff for use of the network by another licensed distribution network operator where charges are linked to flows out of/into the other licensed distribution network from its end users or further nested networks.
RRP	Regulatory reporting pack, a dataset produced each year by each regional distribution network operator for Ofgem.
Settlement period	One of 46, 48 or 50 consecutive periods of a half hour starting at 0:00 UK clock time on each day.
Standard distribution licence conditions	The standard conditions of the electricity distribution licence that have effect under section 8A of the Electricity Act 1989 (introduced by section 33 of the Utilities Act 2000).
System simultaneous maximum load	The maximum load for the GSP Group as a whole.

Term	Explanation
Unit	Where the context permits, the word unit refers to kWh.
Unit rate	A charging or payment rate based on units distributed or units generated. Unit rates are expressed in p/kWh. Tariffs applied to multi-rate meters and/or using several time bands for charging have several unit rates.

SCHEDULE 17 – EHV CHARGING METHODOLOGY (FCP MODEL)

Annex 1 – Implementation Guide

1 Scope

This Annex describes the definitions, input data and power flow analyses required for modelling the DNO Party's Distribution System to enable the FCP methodology to be implemented as set out in the EDCM. The output data are also described.

2 Power Systems Analysis

2.1 The DNO Parties routinely analyse their Distribution Systems using power system analysis tools to identify where limitations exist on the network; this information is used to plan reinforcements.

2.2 Planning of a Distribution System (to satisfy the requirements of the Act and the Distribution Licences) using a power system analysis tool requires the development of a network model which represents the actual Distribution System and the application of demand data that represent the demands that the Distribution System will be required to deliver whilst satisfying the nationally defined security standard, ER P2/6.

2.3 The aim of using power flow analysis for pricing purposes is to replicate the reinforcement assessment process and determine the costs of future network reinforcements in order to generate cost-reflective incremental charges.

2.4 The DNO Parties use a variety of software tools to model their respective Distribution Systems for the purposes of operating and planning Distribution Systems. The Authority and the DNO Parties have agreed that it is not appropriate to prescribe which software tool is used for the analysis of the Distribution System, as it is for each DNO Party to satisfy itself that it is using the appropriate tools for planning and operation of its Distribution System.

2.5 The following sections describe the definitions, input data and the power flow analyses required to model the Distribution System for pricing purposes. The calculation of reinforcement costs and the main outputs are discussed.

3 Definitions

In this Schedule 17, unless the context otherwise requires, the expressions below shall have the meanings set out below.

Term	Definition
Active Power	The product of the voltage, current and cosine of the phase angle between them, measured in watts.
Authorised Network Model	The model that represents the DNO Party's entire EHV network (from the GSP level down to and including the HV busbar at the EHV/HV transformation level), as described in Paragraph 2.3 and section 4 of this Annex 1.
Branch	A representation of an asset, collection of assets or part of an asset of the DNO Party's EHV network through which Active Power flows as a consequence of supply to or export from a customer or busbar on the DNO's HV or EHV networks. A Branch must only be connected between two Nodes. A Branch should conform to the following: • there can be more than one Branch between the same two Nodes; • a three winding transformer may be represented by three Branches (one Branch for each of the windings) configured in a star formation; • the Active Power flowing out of one end of a Branch should equal the Active Power flowing into the other end of the Branch less any losses within the Branch; • shunt reactors and capacitors are not Branches; • earthing transformers, resistors and reactors are not Branches; and • a Branch may constitute a collection of assets e.g. a circuit constituting overhead lines and cables. When combining

	assets into a Branch, there is a need to consider the reinforcement solution for the Branch in the next stages for the Use of System Charging calculation.
Branch Rating	The Branch Ratings selected for the Authorised Network Model should be derived by appropriate consideration of the time of day / season / general nature of load profile (i.e. continuous, cyclic, etc.) represented within the model.
Bulk Supply Point (BSP)	A supply point on the DNO Party's Distribution System representing an EHV/EHV transformation level e.g. 132/33kV.
Circuit	The part of a Distribution System between two or more circuit breakers, switches and/or fuses inclusive. For the avoidance of doubt a circuit can contain a number of Branches and Nodes. A Circuit may include transformers, reactors, cables and overhead lines. Busbars are not considered as Circuits.
Circuit Branch	A categorisation used in the derivation of Branch reinforcement costs for Branches that represent an interconnection (or part of an interconnection) between substations and which operate at a single voltage level.
Circuit TSG	A Test Size Generator connected to: • the downstream / child Network Group of a GSP or BSP (e.g. connected to the lower voltage busbars of a Primary Substation connected to a particular BSP group, or the lower voltage busbars of a BSP connected to a GSP group) or • connected to the Exit / Entry Point of EDCM Connectees within a particular Network Group. The Circuit TSG has an export capacity set to a test size as described in section 7.10 (Test Size Generators) of Annex 1.

Connection Node	A Node which is a point of connection to one of the following: • an Entry Point or the Sole Use Assets connecting the Entry Point; or • an Exit Point or the Sole Use Assets connecting the Exit Point; or • the DNO Party's HV network; or • a Distribution System of another DNO Party or IDNO Party.
Contingency Analysis	The analysis to determine the effect on power flows for the Authorised Network Model under N-1 and where necessary, N-2 contingencies.
Diversity Factor	A scaling factor calculated as the ratio of the maximum demand observed at a given location on the network and the aggregate of the individual maximum demands observed at multiple locations connected downstream (i.e. further from source) of the given location, taking account of losses. Such factors provide a means of recognising that the maximum demands observed at individual locations (e.g. substations at a given voltage level) on a section of network may not be coincident. Details of the calculation of Diversity Factors are set out in section 5.9 (Diversity Factors) of Annex 1.
EDCM	has the meaning given to that expression in Paragraph 1
EDCM Connectee	means a Connectee whose Connected Installation is a Designated EHV Property as defined in Standard Conditions 50A.11 and 13B.6 of the Electricity Distribution Licence. An EDCM Connectee may be an EDCM (Load) Connectee or EDCM (Generation) Connectee, as appropriate.
EDCM Customer	means a Customer whose Customer Installation is a Designated EHV Property as defined in Standard Conditions 50A.11 and 13B.6 of the Electricity Distribution Licence.

EDCM Generation	means a Generator Installation that is a Designated EHV Property as defined in Standard Conditions 50A.11 and 13B.6 of the Electricity Distribution Licence.
EHV	Extra High Voltage.
ER P2/6	Energy Network Association's Engineering Recommendation P2/6 which is the planning standard for security of supply to be used by the DNO Parties.
ETR 130	Energy Network Association's Engineering Technical Report 130 which is the Application Guide for assessing the capacity of Distribution Systems to which Generation Installations are connected.
Extra High Voltage (EHV)	Refers to voltages operating on the Authorised Network Model at 22kV or higher.
FCP	Has the meaning given to that expression in Paragraph 2.1
Grid Supply Point (GSP)	A point of supply from the National Electricity Transmission System to the DNO Party's Distribution System.
Headroom	For each Branch that is identified as being overloaded from the application of a TSG, the headroom is considered to be the largest power output (MW) of the respective TSG before the overload occurs within the Branch in question. The Headroom calculation is run with Minimum Demand Data, and with N-1 Contingencies applied.
High Voltage (HV)	Refers to voltages operating on the Authorised Network Model above 1000 volts but lower than 22kV.
Long Term Development Statement (LTDS)	The Long Term Development Statement as detailed by Licence Condition 25 of the Distribution Licences.
Maximum Demand Data	The Network Demand Data that is applied to the demand (load) analysis for N-1 contingency testing. The construction of Maximum Demand Data is described in section 5.35 (Maximum

	Demand Data for Demand (Load) Analysis) of Annex 1.
Maintenance Demand Data	The Network Demand Data that is applied to the demand (load) analysis for N-2 contingency testing (by supposition, this would consider N-1 contingencies). The construction of Maintenance Demand Data is described in section 5.41 (Maintenance Demand Data for Demand (Load) Analysis) of Annex 1.
Minimum Demand Data	The Network Demand Data that is applied to the Demand (generation) analysis. The construction of Minimum Demand Data is described in section 5.46 (Minimum Demand Data for Demand (Generation) Analysis) of Annex 1.
N-1 Contingency	An N-1 Contingency considers an N-1 Event occurring on the Authorised Network Model and models the consequential network actions and where appropriate constraints on customer demands. This is used to ensure that the resultant flows in Branches that remain in service are within rated capacity.
N-1 Event	An N-1 Event is a First Circuit Outage (FCO) as explained in ER P2/6. It signifies a fault or arranged outage on the network which would result in a section of the network defined by the relevant protection scheme to sectionalise and isolate the faulty section, or isolates the section to be worked on for maintenance, resulting in zero power flow in the affected network. N-1 Events should consider an outage of a complete Circuit and only consider faults or arranged outages occurring with the network initially running under Normal Running Arrangements.
N-2 Contingency	An N-2 Contingency considers an N-2 Event occurring on the Authorised Network Model and models the consequential network actions and where appropriate constraints on customer demands. This is used to ensure that the resultant flows in Branches that remain in service are within rated capacity.
N-2 Event	An N-2 Event is a Second Circuit Outage (SCO) as explained in ER P2/6. It signifies the occurrence of a fault on the network at the same time as a planned outage which would result in a section

	of the network defined by the relevant protection scheme to sectionalise and isolate the faulty section. As N-2 Events are considered to have occurred at the same time as a planned outage, they are confined to the maintenance period, as designated by the DNO Party. Maintenance Demand Data is used when considering N-2 Events.
National Electricity Transmission System	Has the meaning given to that expression in the CUSC
Negative Load Injection	A Negative Load Injection is a negative value of load calculated and applied to a source substation within the network model to represent the effects of diversity between associated downstream demands upon the actual demand observed at the source substation.
Net Diversity Factor	A scaling factor that represents the diversity between the maximum demands observed at substations at different levels of a network, which may be derived by multiplying Diversity Factors representing the diversity between interim levels.
network	This is a reference to the DNO Party's Distribution System, or to a particular part of that Distribution System.
Network Demand Data	This is the load and generation which is used to populate the Authorised Network Model. Network Demand Data is constructed of Network Demand Data (Load) and Network Demand Data (Generation).
Network Demand Data (Generation)	Generation export applied within the Authorised Network Model at Nodes representing the Entry Point for each EHV connected customer with an agreed maximum export capacity factored according to ER P2/6, where appropriate.
Network Demand Data (Load)	The load applied within the Authorised Network Model at Nodes representing the Exit Point for each EHV customer and the lower voltage busbars at substations representing transformation points between Network Groups or EHV/HV substations.

Network Group	This is one of the parts of the Authorised Network Model described in Paragraph 2.7 and section 6 (Network Groups) of Annex 1.
Node	A representation of a point on the DNO Party's EHV network that is a point of connection between a Branch and one or more of the following: • another Branch; or • an Entry Point or the Sole Use Assets connecting the Entry Point; or • an Exit Point or the Sole Use Assets connecting the Exit Point; or • the DNO Party's HV network; or • the Distribution System of another DNO Party or IDNO Party; or • the National Electricity Transmission System.
Normal Running Arrangements	The DNO Party's EHV network with no system outages i.e. with no planned outages (e.g. for maintenance) and no unplanned outages (e.g. subsequent to a fault).
Point of Common Coupling	The point on the network where the power flow associated with the single customer under consideration, may under some (or all) possible arrangements interact with the power flows associated with other customers, taking into account all possible credible running arrangements
Primary Substation	A substation on the DNO Party's Distribution System transforming the voltage from EHV to HV, e.g. 33/11kV
Reactive Power	The product of the voltage and current and the sine of the phase angle between them, measured in units of voltamperes reactive.
Regulatory Year	has the meaning given to that expression in the DNO Party's

	Distribution Licence.
Scaling Factor	A factor which is calculated for each Grid Supply Point (or group of normally interconnected Grid Supply Points) to calculate the Network Demand Data (Load) element of the Minimum Demand Data.
Sole Use Assets	Assets in which only the consumption or output associated with a single customer can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements, i.e. all assets between the customer's Entry/ Exit Point(s) and the Point(s) of Common Coupling with the general network.
Source Substation	Any substation which connects, via transformers and under Normal Running Arrangements, a particular Network Group to its “upstream” source. For example, for a 33kV group, the Source Substation is taken as the interconnecting 132/33kV grid transformers. A single Network Group may have more than one Source Substation.
Substation TSG	A Test Size Generator connected to the lower voltage side of each Source Substation within a Network Group. The Substation TSG has an export capacity set to a test size as described in section 7.10 (Test Size Generators) of Annex 1.
Test Size Generator (TSG)	A hypothetical generator connected to the Authorised Network Model to model new discrete generation on the network, exporting at unity power factor, within the Generation Power Flow Studies described in section 7.9 (Demand (Generation) Analysis) of Annex 1.
Transformer Branch	A categorisation used in the derivation of Branch reinforcement costs, for Branches that represent transformation between different voltage levels.

4 Network Modelling

4.1 This section describes the input data required to model the Distribution System for pricing purposes. The FCP methodology requires the Authorised Network Model to be populated with different load and generation levels, corresponding to the Demand (load) and Demand (generation) scenarios being analysed.

Authorised Network Model

4.2 This is the network model that represents the entire EHV network, from the GSP level down to and including the HV busbar at the EHV/HV transformation level and includes all authorised (i.e. sanctioned by the DNO Party) schemes (reinforcement, diversion and new connection works) that are anticipated to be constructed and operational at the time of Maximum Demand in the Regulatory Year for which the Use of System Charges are being calculated. Where a part of a single authorised network project is expected to be commissioned and operational in the Regulatory Year for which Use of System Charges are to be calculated then the DNO Party may, if appropriate, model the fully completed network project. The model should also include a representation of the National Electricity Transmission System.

4.3 The Authorised Network Model may be constructed so that power flow analysis may be conducted separately upon individual Grid Supply Points (or groups of normally interconnected Grid Supply Points) provided that there is no interconnection with adjacent Grid Supply Points considered in the analysis of the respective contingency conditions and any interaction arising from the transfer of demand and generation is correctly accounted for.

4.4 Due to the timings difference between the publication of the LTDS and the creation and publication of use of system tariffs, the Authorised Network Model may contain revised assumptions to the LTDS information.

4.5 A representation of the National Electricity Transmission System shall be included in the model. The complexity of the representation shall be dependent on the level of interconnection of Grid Supply Points via the DNO Party's EHV network. The representation may be:

(a) a simple generator in-feed at the Grid Supply Point; or

(b) the use of equivalent circuits to model the interconnections of the Grid Supply Points via the National Electricity Transmission System; or

(c) a full replication of the National Electricity Transmission System electrically local to the DNO Party's Distribution System; or

(d) a full replication of the whole of the National Electricity Transmission System.

4.6 The method of representation should be carefully selected in order to produce a suitable representation of the flows into the DNO Party's EHV network from the National Electricity Transmission System during both Normal Running Arrangements and N-1 Contingency scenarios.

4.7 The Authorised Network Model can be modelled so that it takes into account every different section of a circuit, including individual underground cables and overhead line sections, with each different type forming a separate Branch in the model connected between two Nodes. However, this approach can lead to known issues associated with the non-convergence for a power flow solution of models with large numbers of Nodes and large numbers of Branches with very small impedances.

4.8 It is acceptable to model a single Branch to represent a composite of multiple subcomponents of underground cable and overhead line. The impedance of a composite Branch can be calculated from the types of subcomponent that make up the overall Circuit length. The rating of a composite Branch can be obtained by examining the rating of all the branch subcomponents and the lowest rating used as the limiting section that overloads first. For underground cables the impedance and rating is dependent upon the construction type of the cable, cross sectional area of the conductor, conductor material, whether the cable is laid directly in the ground or in ducts. Similarly, for overhead lines the impedance and rating is dependent upon the construction type of the overhead line structures (to take account of the relative positions of the conductors), the conductor material and type and cross sectional area. This information can then be used to determine the Branch impedance and minimum component rating applied in the Authorised Network Model.

4.9 As an example, if Figure 2 represents the actual network, the approach described above to produce the EHV network model would reduce it to a nodal model representation as shown in Figure 3. Table 7 shows an example of the data held relating to Figure 2 with the individual subsections being cross referenced to each branch; Table 8 lists the parameters used for the nodal model shown in Figure 3.

Figure 2 - An example of a section of network to be converted into a nodal model.

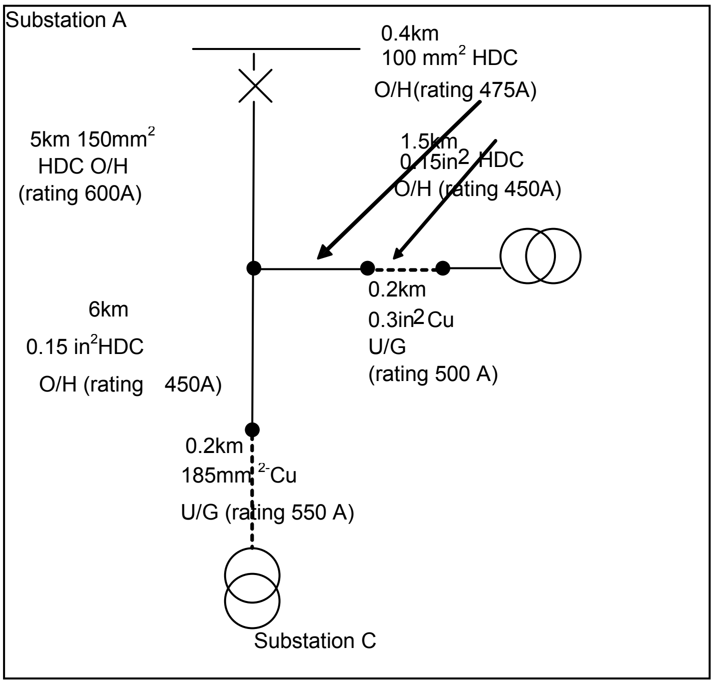


Figure 3 - The resultant nodal model representative of the example network in Figure 2.

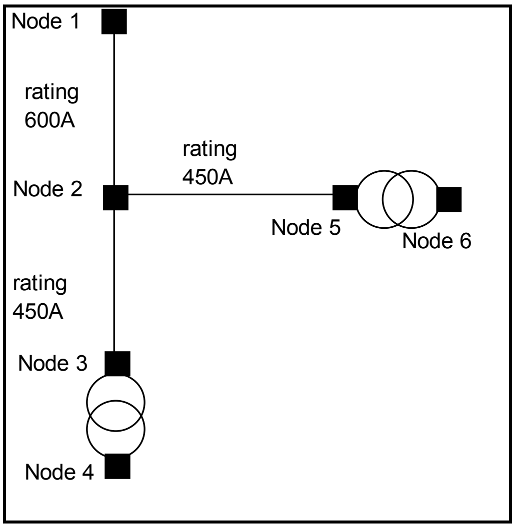


Table 7 - An example of the information held separately relating to Figure 1 which is used to provide the composite Branch parameters.

Branch	Line Section	Type	Length	Rating	R(p.u.)[1]	X(p.u.)
Node 1 to Node 2	1	150mm^2 HDC O/H	5km	600A	0.001	0.01
Node 2 to Node 3	1	0.15in^2 HDC O/H	6km	450A	0.0018	0.0054
Node 2 to Node 3	2	185mm^2 Cu U/G	0.2km	550A	0.00003	0.0003
Node 2 to Node 5	1	100mm^2 HDC O/H	0.4km	475A	0.00004	0.0004
Node 2 to Node 5	2	0.3in^2 Cu U/G	0.2km	500A	0.00003	0.0001
Node 2 to Node 5	3	0.15in^2 HDC O/H	1.5km	450A	0.00045	0.00135

Table 8 - Composite Branch parameters used for the nodal model shown in Figure 3 above.

Branch	Branch Rating	R(p.u.)	X(p.u.)
Node 1 to Node 2	600A	0.001	0.01
Node 2 to Node 3	450A	0.00183	0.0057
Node 2 to Node 5	450A	0.00052	0.00185

[1] For the sake of simplicity ratings, resistance (R) and reactance(X) values given above are assumed and should be used only for illustrative purposes such as the given example to calculate equivalent Branch ratings and parameters for a composite Branch.

Inclusion of Distribution Systems of IDNO Parties in the Authorised Network Model

4.10 Where there is a connection between the DNO Party's Distribution System and an EDCM IDNO Party Distribution System, the IDNO Party's network can be represented either by an Exit Point or Entry Point, in a similar manner to that of an ECDM Connectee. In the event that the IDNO Party's network derives its supply from several different connection points on the DNO Party's Distribution System it may become necessary to model some or the entire IDNO network to ensure that the flows at the boundary between the DNO Party's Distribution System and the Distribution System of the IDNO Party are representative of those expected under Normal Running Arrangements and Contingency scenarios.

5 Network Demand Data

5.1 This section 5 describes the input data required to model the Distribution System for FCP purposes.

Network Demand Data (Load)

5.2 The demands (load) in the Authorised Network Model will be based on LTDS network data as produced by the DNO Party. It is necessary to create a 10-year demand (load) set to assess the network for the 10-year study period. The following Network Demand Data is required as the basis for populating the Authorised Network Model:

(a) Maximum Demands at each Connection Node;

(b) Maximum Demands at Grid Supply Points;

(c) Minimum Demands at Grid Supply Points; and

(d) Maximum Demands at Bulk Supply Points or other intermediate substations.

5.3 The load estimates in the LTDS are normally cleansed and validated ensuring:

(a) maximum loads that are recorded reflect Normal Running Arrangements;

(b) application of suitable weather correction is considered, if appropriate; and

(c) latent demand is accounted for in accordance with the guidance contained in ETR 130.

5.4 The LTDS forecasts the demand (loads) for 5 years. The remaining years (years 6 to 10) are to be assessed by the DNO Party using the appropriate engineering forecasts and local knowledge and information.

5.5 Where new EDCM Customers are included in the Authorised Network Model, their demands will be individually assessed and estimated by the DNO Party.

Network Demand Data (Generation)

5.6 Existing EDCM Generation in the model will be based on the Maximum Export Capacity for the EDCM Generation. Depending on the power flow studies being undertaken these may be scaled by an F factor as described in ER P2/6. Where sufficient actual recorded network data exists, a generator's site-specific F factor may be calculated, as described in ETR 130.

Modelling of Customers with both Load and Generation

5.7 'Import/Export' Connectees (Connectees that have the ability to import electricity from and export electricity to the Distribution System) require special consideration. The import and export flows associated with these customers should not be modelled simultaneously in either the Demand (load) analysis or the Demand (generation) analysis.

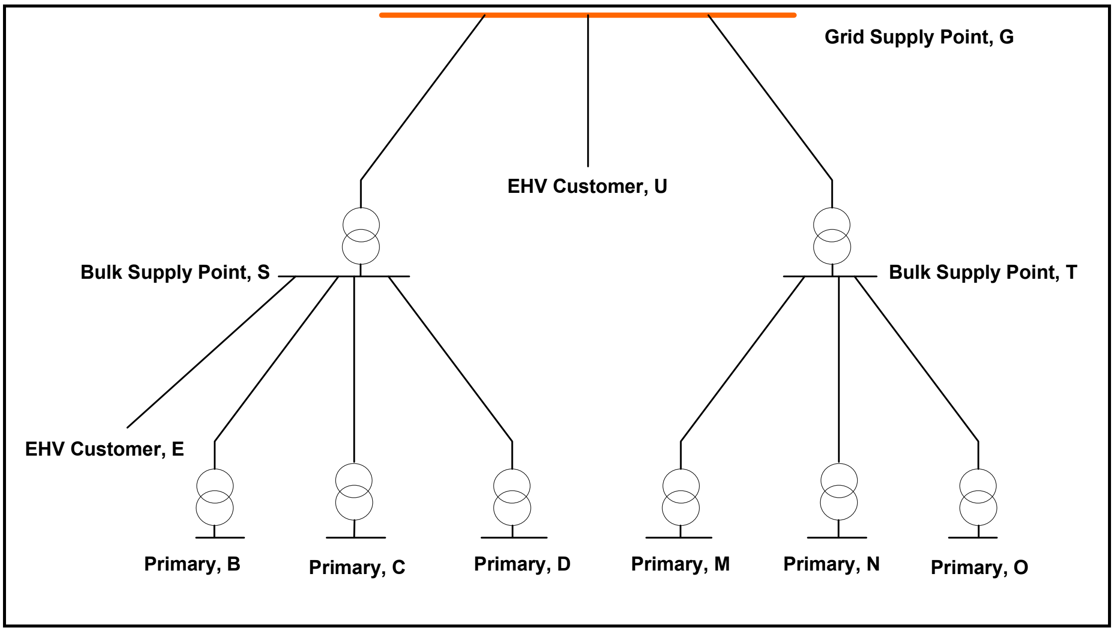
5.8 The flows associated with these customers should contribute solely to the Network Demand Data (Load) element of the Maximum Demand Data and Maintenance Demand Data data sets or solely to the Network Demand Data (Generation) element of the Minimum Demand Data data set. These demands should be derived as described in the Maximum Demand Data for Demand (Load) Analysis, Maintenance Demand Data for Demand (Load) Analysis and Minimum Demand Data for Demand (Generation) Analysis sections.

Diversity Factors

5.9 The demands that are required to be populated in the Authorised Network Model need to be set so the modelled demand supplied through a GSP is equal to the Maximum Demand at the GSP as described in the Network Demand Data (Load) section. This may be achieved by using Diversity Factors to modify the Connection Node maximum demands or by the use of Negative Load Injections. The following describes acceptable methods to achieve this requirement.

5.10 To aid the description a simple network is shown in Figure 4 below which will provide a basis for the examples.

Figure 4 - Example model for the calculation of Diversity Factors.



Method 1 – Hierarchical Diversity Factors

5.11 Networks are typically built as a hierarchy. The typical hierarchy levels are Primary Substation, Bulk Supply Points and Grid Supply Points. There may also occasionally be other intermediate levels such as 132kV switching substations. A Diversity Factor can then be calculated for each required substation. The Diversity Factor is calculated as the maximum demand at that substation divided by the sum of the maximum demands of all points of the network at the next lower hierarchy served by that substation plus an allowance for losses in that part of the network.

5.12 In our example, for Bulk Supply Point, S (see Figure 4), supplying three Primary Substations, B, C and D, and an EDCM Customer E, the Diversity Factor is derived as:

$$DF_s = \frac{MD_s}{MD_B + MD_C + MD_D + MD_E + losses_{s\rightarrow}}$$

Where:

DF_S	=	diversity factor
MD_S	=	maximum demand at substation S
MD_B	=	maximum demand at substation B
MD_C	=	maximum demand at substation C
MD_D	=	maximum demand at substation D
MD_E	=	maximum demand at substation E
$losses_{S\rightarrow}$	=	line losses in the downstream network supplied from Bulk Supply Point S

5.13 Similarly for Grid Supply Point, G, supplying two Bulk Supply Points, S and T, and an EDCM Customer U, the Diversity Factor is derived as:

$$DF_G = \frac{MD_G}{MD_S + MD_T + MD_U + losses_{G\rightarrow}}$$

Where:

DF_G	=	diversity factor
MD_G	=	maximum demand at substation G
MD_S	=	maximum demand at substation S
MD_T	=	maximum demand at substation T
MD_U	=	maximum demand at substation U
$losses_{G\rightarrow}$	=	line losses in the downstream network supplied from Grid Supply Point G

5.14 Diversity Factors are calculated separately for each substation at each level. In our example, Diversity Factors would be calculated for substations S, T, and G. A Net Diversity Factor is then applied to each Connection Node based on the product of Diversity Factors of all the Substations that supply that Connection Node. In the example, the following Net Diversity Factors would be applied to each of the Connection Nodes.

Table 9 - Calculation of Net Diversity Factors - Hierarchical Diversity Factors.

Connection Node	Maximum Demand	Net Diversity Factor	Demand to be applied to the Network Model
Primary, B	MD_B	$DF_G * DF_S$	$DF_G * DF_S * MD_B$
Primary, C	MD_C	$DF_G * DF_S$	$DF_G * DF_S * MD_C$
Primary, D	MD_D	$DF_G * DF_S$	$DF_G * DF_S * MD_D$
EHV Customer, E	MD_E	$DF_G * DF_S$	$DF_G * DF_S * MD_E$
Primary, M	MD_M	$DF_G * DF_T$	$DF_G * DF_T * MD_M$
Primary, N	MD_N	$DF_G * DF_T$	$DF_G * DF_T * MD_N$
Primary, O	MD_O	$DF_G * DF_T$	$DF_G * DF_T * MD_O$
EHV Customer, U	MD_U	DF_G	$DF_G * MD_U$

5.15 Diversity Factors are applied to both the Active Power and Reactive Power demands at each Connection Point thus ensuring the power factor of the demand remains unchanged.

Method 2 – Single Diversity Factors

5.16 Where a network has significant interconnection or subject to regular rearrangement (e.g. Primary Substations being transferred between Bulk Supply Points) the use of a single Diversity Factor for all the demand supplied by a Grid Supply Point (or a set of interconnected Grid Supply Points) may be appropriate. The Diversity Factor for the GSP is calculated as the Maximum Demand at the GSP divided by the sum of all the Maximum

Demands of each Connection Node supplied from that GSP plus an allowance for losses.

5.17 Using the example shown in Figure 4 a single Diversity Factor for Grid Supply Point, G can be calculated as:

$$DF_{G1} = \frac{MD_G}{MD_B + MD_C + MD_D + MD_E + MD_M + MD_N + MD_O + MD_U + losses}$$

Where:

DF_{G1}	=	diversity factor
MD_G	=	maximum demand at substation G
MD_B	=	maximum demand at substation B
MD_C	=	maximum demand at substation C
MD_D	=	maximum demand at substation D
MD_E	=	maximum demand at substation E
MD_M	=	maximum demand at substation M
MD_N	=	maximum demand at substation N
MD_O	=	maximum demand at substation O
MD_U	=	maximum demand at substation U
$losses_{S\rightarrow}$	=	network losses in the system shown in Figure 4

5.18 The Net Diversity Factor in this method is equal to the calculated single Diversity Factor. In the example the following Net Diversity Factors would be applied to each of the Connection Nodes.

Table 10 - Calculation of Net Diversity Factors – Single Diversity Factors

Connection Node	Maximum Demand	Net Diversity Factor	Demand to be applied to the Network Model
Primary, B	MD_B	DF_{G1}	$DF_{G1} * MD_B$
Primary, C	MD_C	DF_{G1}	$DF_{G1} * MD_C$
Primary, D	MD_D	DF_{G1}	$DF_{G1} * MD_D$
EHV Customer, E	MD_E	DF_{G1}	$DF_{G1} * MD_E$
Primary, M	MD_M	DF_{G1}	$DF_{G1} * MD_M$
Primary, N	MD_N	DF_{G1}	$DF_{G1} * MD_N$
Primary, O	MD_O	DF_{G1}	$DF_{G1} * MD_O$
EHV Customer, U	MD_U	DF_{G1}	$DF_{G1} * MD_U$

5.19 Diversity Factors are applied to both the Active Power and Reactive Power demands at each Connection Point thus ensuring the power factor of the demand remains unchanged.

Method 3 – Negative Load Injections

5.20 A Negative Load Injection is a negative value of load calculated and applied to a source substation within the network model to represent the effects of diversity between associated downstream demands upon the actual demand observed at the source substation.

5.21 Negative Load Injections are applied at a substation to ensure that the demand at the substation equals the required Maximum Demand for that substation. Negative load injections are normally placed at Bulk Supply Points, other intermediate substations (such as 132kV switching substations) and Grid Supply Points.

5.22 The amount of negative load injection required to be applied at a substation is calculated as the maximum demand at that substation minus the sum of the maximum demands of all points of the network at the next lower hierarchy served by that substation plus an allowance for losses in that part of the network.

5.23 In our example, for Bulk Supply Point, S, supplying three Primary Substations, B, C and D, and an EDCM Customer E, Negative Load Injection is derived as:

$$NLI_S = MD_S - (MD_B + MD_C + MD_D + MD_E + losses_{S\rightarrow})$$

Where:

NLI_{G1}	=	negative load injection
MD_S	=	maximum demand at substation S
MD_B	=	maximum demand at substation B
MD_C	=	maximum demand at substation C
MD_D	=	maximum demand at substation D
MD_E	=	maximum demand at substation E
$losses_{S\rightarrow}$	=	line losses in the downstream network supplied from Grid Supply Point G

5.24 Similarly for Grid Supply Point, G, supplying two Bulk Supply Point, S and T, and an EDCM Customer U, Negative Load Injection is derived as:

$$NLI_G = MD_G - (MD_S + MD_T + MD_U + losses_{S\rightarrow})$$

Where:

NLI_G	=	negative load injection
MD_G	=	maximum demand at substation G
MD_S	=	maximum demand at substation S
MD_T	=	maximum demand at substation T
MD_U	=	maximum demand at substation U
$losses_{S\rightarrow}$	=	line losses in the downstream network supplied from Grid Supply Point G

5.25 The value of Negative Load Injection calculated is a negative number. This is modelled as a negative load (or in fact generation) at the substation busbar so that the incoming flow matches the required maximum demand for that substation. Negative Load Injections are applied as an Active Power injection only. No Reactive Power injection is applied.

An Implementation of Diversity Factors Using Multiple Load Sets

5.26 The use of Network Groups for analysis in the FCP methodology allows for different levels of the network to be loaded independently with different Network Demand Data (Load). By loading all Primary Substations and EDCM Customers with their maximum demands as recorded in the LTDS, the total system demand at each GSP will be significantly higher than the demand reported to National Grid for the Week 24 submission[2]. This excessive loading of the higher voltage network levels would give rise to premature reinforcement at this level as diversity has not been considered. However, when considering this Primary Substation load set only reinforcements between the lower voltage busbars of the Primary Substations and the lower voltage busbars of the supplying higher voltage substations are considered. The assets observed for overloads and hence need reinforcing are therefore the Primary Substation transformers and their supplying EHV Circuits, if applicable.

Example on a radial network

5.27 An example showing a radial network loaded with a Primary Substation load set is shown in Figure 5 and the shaded box shows the assets considered when looking for overloads. All upstream Branches should be ignored if they overload as these will be tested by a separate load set.

5.28 With the Primary Substation level tested, the loads connected to Primary Substations and EDCM Customers may be removed and the BSP substations maximum demands loaded as per the LTDS. An alternative approach to removing these loads would be to retain them in the network model but to scale them using appropriate diversity factors to match Maximum Demands at the BSP substations (as set out in Method 1).

5.29 The BSP load set can then be used to test the network assets between the BSP lower voltage busbar and the supplying GSP. Figure 6 shows the same network but with the BSP loads applied, the assets in the shaded box are the ones observed for overloads. It is accepted that using all BSP maximum demands (load) the resultant loads at the GSPs will not equal the maximum demands reported to National Grid for the Week 24 submission. The extra demand (load) may overload the GSP transformers, however, these are zero-cost Branches as they are transmission assets; the Reinforcement Cost Calculation Principles section describes zero-cost Branches further.

[2] In compliance with the Grid Code, all DNO's provide National Grid with yearly maximum demand data associated with each GSP in their network, this is known as the Week 24 submission.

Figure 5 - Network schematic showing Primary Substations loaded with maximum demands and the network assets monitored for overloads.

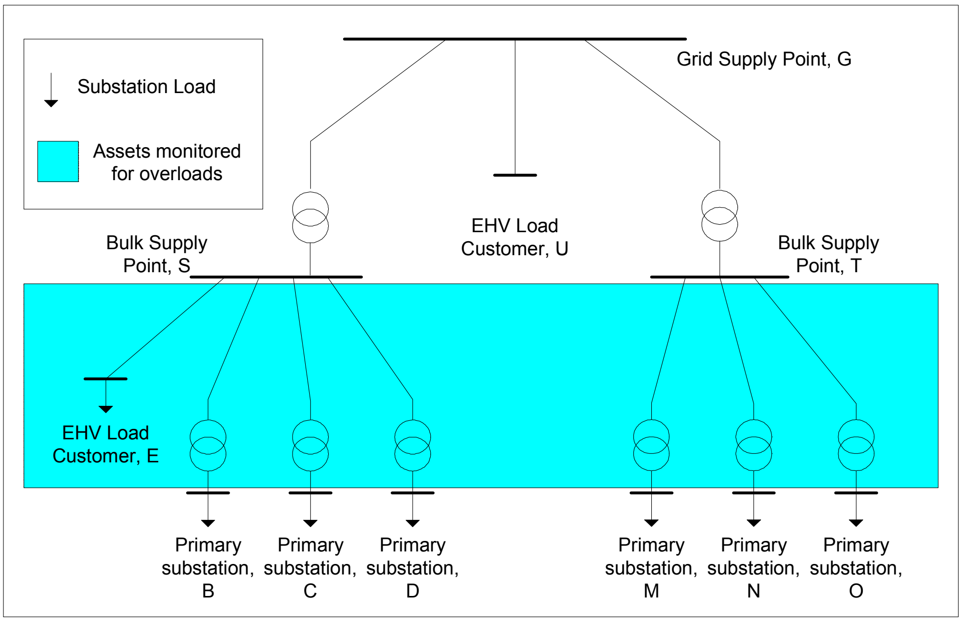
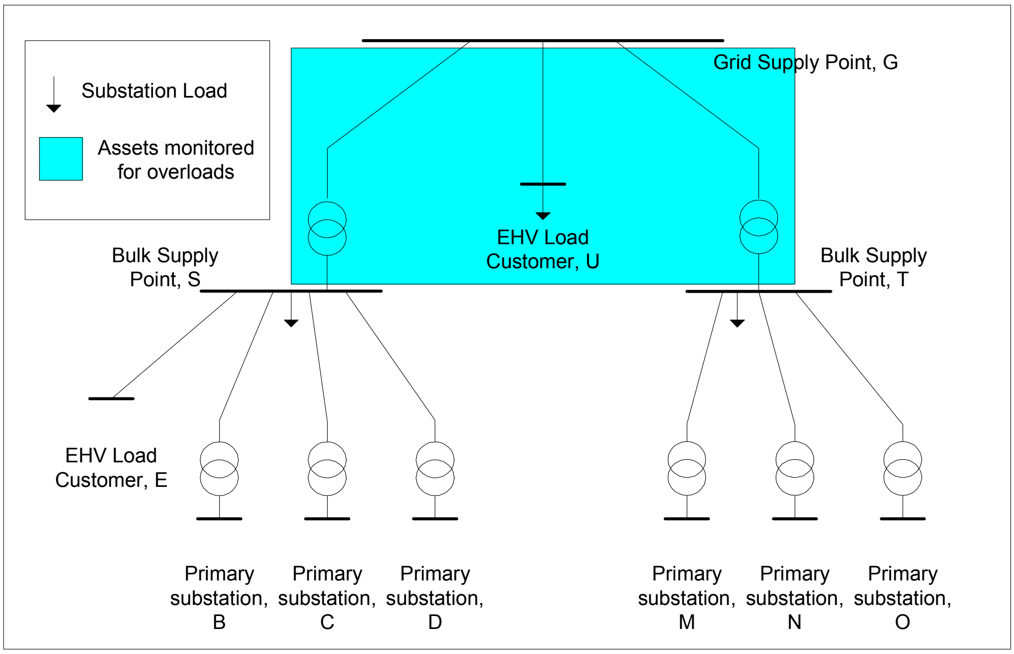


Figure 6 - Network schematic showing Primary Substations loads removed and BSP loads added, also showing the network assets monitored for overloads.



An implementation of diversity factors using multiple load sets (meshed and radial mix)

5.30 Where networks are comprised of a mix of radial and meshed sections (such as shown in Figure 7), it may not be appropriate to consider all substations as being loaded to their maximum demands. This implementation involves the application of hierarchical Diversity Factors to loads on meshed sections while the loads on the radial sections remain unchanged.

The procedure is described below.

Calculation of hierarchical diversity factors:

5.31 Hierarchical diversity factors for each network group are calculated as described in Method 1.

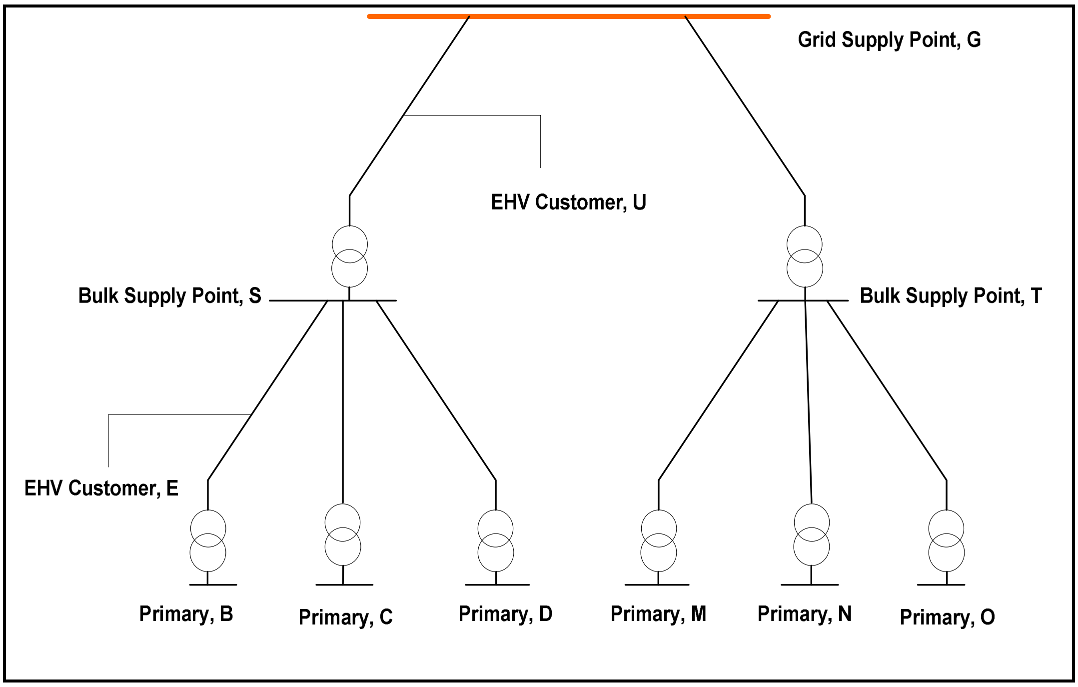
Application of the hierarchical diversity factors:

5.32 The hierarchical diversity factors are applied only to the loads on meshed sections (see table below).

Multiple network analyses:

5.33 The Primary Substation level is loaded and used to test for overloaded Branches between the Primary Substations and the BSPs (excluding any BSP transformers). To test for overloaded Branches between a BSP and a GSP, all downstream demand (load) supplied from the BSPs are removed - for example, demand (load) connected to Primary Substations B, C, D and EDCM Customer E would be removed when testing for overloaded Branches between BSP S and GSP G. BSP loads are then applied to the network model.

Figure 7 - Implementation of Diversity Factors using multiple load sets



5.34 The final load which applied at each substation is shown in the table below:

Table 11 - Calculation of Diversity Factors – Multiple load sets (meshed and radial mix).

Connection Node	Maximum Demand	Diversity Factor	Demand to be applied to the Network Model
Primary, B	MD_B	DF_S	$MD_B * DF_S$
Primary, C	MD_C	*1.00*	MD_C
Primary, D	MD_D	*1.00*	MD_D
EHV Customer, E	MD_E	DF_S	$MD_E * DF_S$
Primary, M	MD_M	*1.00*	MD_M
Primary, N	MD_N	*1.00*	MD_N
Primary, O	MD_O	*1.00*	MD_O
EHV Customer, U	MD_U	DF_G	$MD_U * DF_G$
Bulk Supply Point, S	MD_S	DF_G	$MD_s * DF_G$
Bulk Supply Point, T	MD_T	*1.00*	MD_T

Maximum Demand Data for Demand (Load) Analysis

Network Demand Data (Generation)

5.35 The Network Demand Data (Generation) element of the Maximum Demand Data shall be constructed with generation output set at zero unless the generation can be considered to have a contribution to security of supply under ER P2/6, in which case the ER P2/6 level of export shall be modelled.

5.36 The contribution of distributed generation to security of supply is dealt with in ER P2/6 through the application of F factors. Each distributed generator is assigned an F factor and this represents the percentage of the generator's declared net capacity that can be considered when assessing network security. ER P2/6 also uses the term 'Persistence' to reduce the F factor for intermittent generation, as the time period (in hours) for which its contribution to security is being assessed increases. Table 2-4 of ER P2/6 recommends values of 'Persistence'; these values are dependent on the demand class being assessed. The value of 'Persistence' to be used for intermittent generation will be as stated in Table 2-4 of ER P2/6 for 'Other outage', using the maximum GSP (or GSP groups') demand instead of the demand class of the demand group.

Network Demand Data (Load)

5.37 The Network Demand Data (Load) element of the Maximum Demand Data shall be constructed based on the Maximum Demands for each load point and either amended (Diversity Factors) or enhanced (Negative Load Injections) by the chosen diversity method (see the Diversity Factors section).

5.38 For the diversity methods 1 and 2 the maximum demand load estimates for each load point is scaled so that the modelled load in the Maximum Demand Data reflects the Grid Supply Point maximum load estimates under Normal Running Arrangement.

5.39 The application of diversity in the derivation of this data needs to be carefully considered and aim to produce, where possible, within the constraints of a single set of demand data, power flows that reflect typical flows under the Maximum Demand conditions; but also enable calculations to be undertaken upon an Authorised Network Model.

5.40 In considering the derivation of the Maximum Demand Data, it must be recognised that power flow analysis based on this Network Demand Data may not replicate the maximum power flow through individual assets that could be seen under all N-1 Contingency conditions, due to the limitations of analysis based upon a limited number of sets of Network Demand Data.

Maintenance Demand Data for Demand (Load) Analysis

Network Demand Data (Generation)

5.41 The Network Demand Data (Generation) element of the Maintenance Demand Data shall be the same as that modelled for the Maximum Demand Data.

Network Demand Data (Load)

5.42 The Network Demand Data (Load) element of the Maintenance Demand Data shall be constructed using the Maximum Demand Data load values scaled down to a minimum of 67% to represent the peak load demands observed during the maintenance period. Where actual loads are higher than 67% of Maximum Demand Data they can be used instead.

5.43 For the diversity methods 1 and 2 the maintenance demand load estimates for each load point are scaled so that the modelled load in the Maintenance Demand Data reflects the Grid Supply Point maintenance peak load estimates under Normal Running Arrangement.

5.44 The application of diversity in the derivation of this data needs to be carefully considered and aim to produce, where possible, within the constraints of a single set of demand data, power flows that reflect typical flows under the peak maintenance demand conditions; but also enable calculations to be undertaken upon an Authorised Network Model.

5.45 In considering the derivation of the Maintenance Demand Data, it must be recognised that power flow analysis based on this Network Demand Data may not replicate the maximum power flow through individual assets that could be seen under all N-2 Contingency conditions, due to the limitations of analysis based upon a limited number of sets of Network Demand Data.

Minimum Demand Data for Demand (Generation) Analysis

Network Demand Data (Generation)

5.46 The Network Demand Data (Generation) element of the Minimum Demand Data shall be Maximum Export Capacity of an Entry Point. There shall be no adjustment for F factors of ER P2/6.

Network Demand Data (Load)

5.47 The Network Demand Data (Load) element of the Minimum Demand Data shall be derived by application of a scaling factor to the Network Demand Data (Load) element of the Maximum Demand Data. Such scaling factors should be separately determined for each Grid Supply Point (or group of normally interconnected Grid Supply Points) using historic data. The scaling factors for each Grid Supply Point (or group of normally interconnected Grid Supply Points) shall be applied to all loads taken from Exit Points supplied from the relevant Grid Supply Point (or group of normally interconnected Grid Supply Points).

5.48 The Scaling Factor for each Grid Supply Point (or group of normally interconnected Grid

Supply Points) is calculated as:

$$\text{Scaling Factor}_G = \frac{\text{Minimum GSP Demand}_G}{\text{Maximum GSP Demand}_G}$$

Where:

Scaling Factor_G	=	scaling factor for Grid Supply Point, G (or group of normally interconnected Grid Supply Points)
Minimum Demand_G	=	minimum demand at Grid Supply Point, G (or group of normally interconnected Grid Supply Points) validated and cleansed with the same criteria as that used for Maximum Demand_G
Maximum Demand_G	=	minimum demand at Grid Supply Point, G (or group of normally interconnected Grid Supply Points) used to populate the Authorised Network Model for the Maximum Demand Data scenario

6 Network Groups

6.1 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 given in ER P2/6. Network Groups are defined at hierarchical levels, each level being defined by the operating voltage of the source substations, such that separate Network Groups are defined for Primary Substation, BSP and GSP levels.

6.2 Each Network Group is a part of the Distribution System that consists of:

(a) the transformation assets at a source substation; and

(b) the network that:

(i) operates at the same voltage as the lower voltage of these transformation assets; and

(ii) is electrically connected to these transformation assets, under Normal Running Arrangements, excluding electrical connection through assets operating at voltages other than the lower voltage of the transformation assets.

6.3 The following exceptions apply:

(a) where a source substation operates, under Normal Running Arrangements, with open point(s) on the lower voltage busbar such that there are separate sections of the busbar that are not electrically connected at the same voltage as the busbar, then these separate sections of busbar, and their associated network, shall be considered as separate Network Groups; and

(b) where multiple source substations, with the same lower voltage of transformation assets, operate in parallel, under Normal Running Arrangements, through network operating at the same voltage as the lower voltage of the transformation assets, then these substations and their associated network shall be considered as a single Network Group.

6.4 Where a Network Group has, under Normal Running Arrangements:

(a) no demand(load) or demand (generation) connected either within the Network Group, or any lower voltage Network Group associated with it; and

(b) the Network Group exists solely for the purposes of providing security of supply support to an adjacent Network Group, through closure of open point(s) between such Network Groups,

then such Network Groups shall be considered as part of the adjacent Network Group to which they provide security of supply support (an example of such instances would be Network Groups that would otherwise be associated with transformers that operate on ‘hot standby’ under Normal Running Arrangements).

6.5 The demand (load or generation) that is considered to be associated with each Network Group is the demand that is connected within the Network Group and also within any lower voltage Network Group that is connected the source Network Group under Normal Running Arrangements.

6.6 Figure 8 shows an example network broken down into a number of Network Groups. This example shows how individual Network Groups may include multiple source substations. This is illustrated by the Level 2 group shown as BSP Group 1. In this example both BSP1 and BSP2 are Source Substations which are encompassed within a single Network Group, due to operation of an interconnected 33kV network between these substations under Normal Running Arrangements.

6.7 Separate Network Groups may be physically connected by circuits but under Normal Running Arrangements there are no flows between the Network Groups either by means of a normally open switch or normally open circuit breaker. Figure 9 shows the same example network as seen in Figure 8 except now the 33kV circuit interconnection between BSP 1 and BSP 2 is run open, creating two level 2 BSP Network Groups, where previously there was only one, with their own separate Source Substations.

6.8 Not all network levels discussed above are applicable across Great Britain with respect to the FCP methodology. In Scotland for example only Level 2 and Level 3 Network Groups are considered as voltages above 33kV are considered transmission and so are not included in the distribution pricing models. In England and Wales all three levels (Level 1, Level 2 and Level 3) as shown in Figure 8 are considered, although depending on the network voltage transformations the Level 2 Network Group may not be present in some cases, as shown at Primary 5. In this case Primary 5's voltage transformation converts 132kV straight to 11kV and hence there is no intermediate distribution through a BSP, Level 2.

Figure 8 - Example network showing three levels of Network Groups.

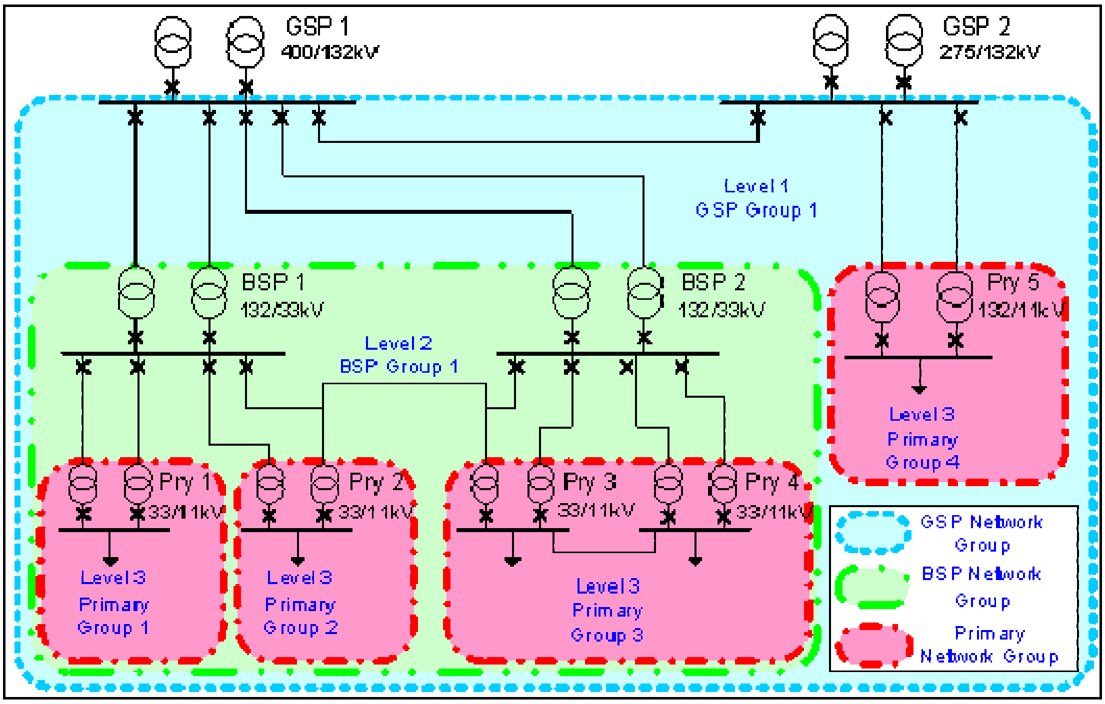
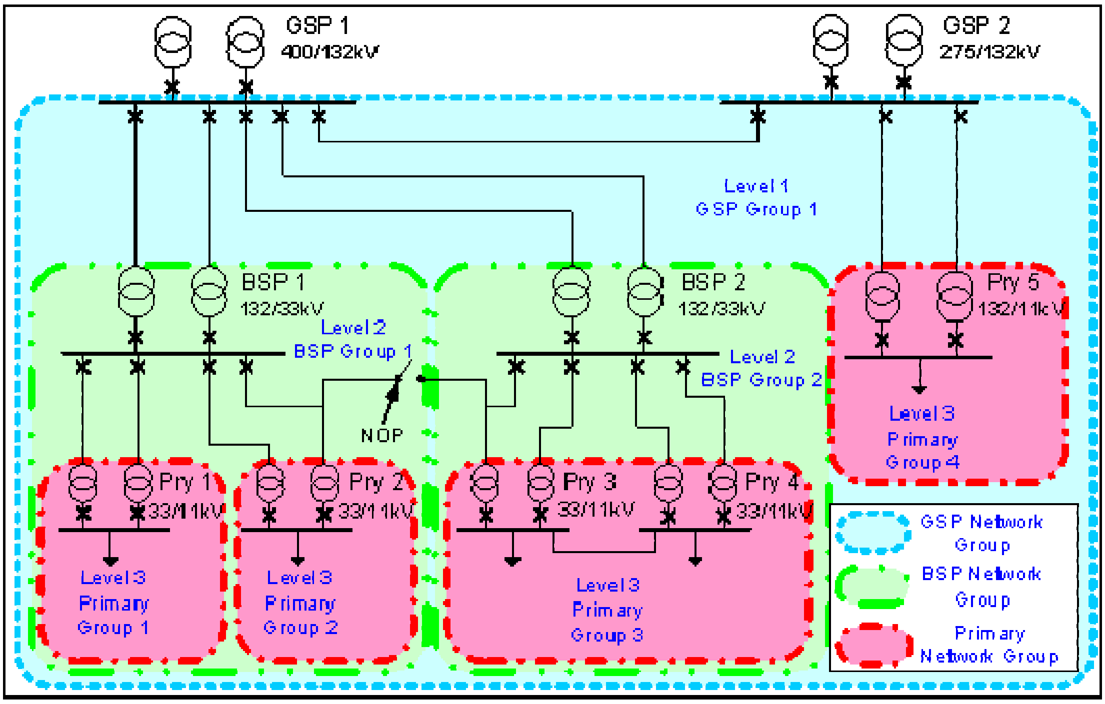


Figure 9 - Example network similar to Figure 7 showing that the addition of the Normally Open Point (NOP) has created two level 2 BSP Network Groups.



7 Power flow analysis process

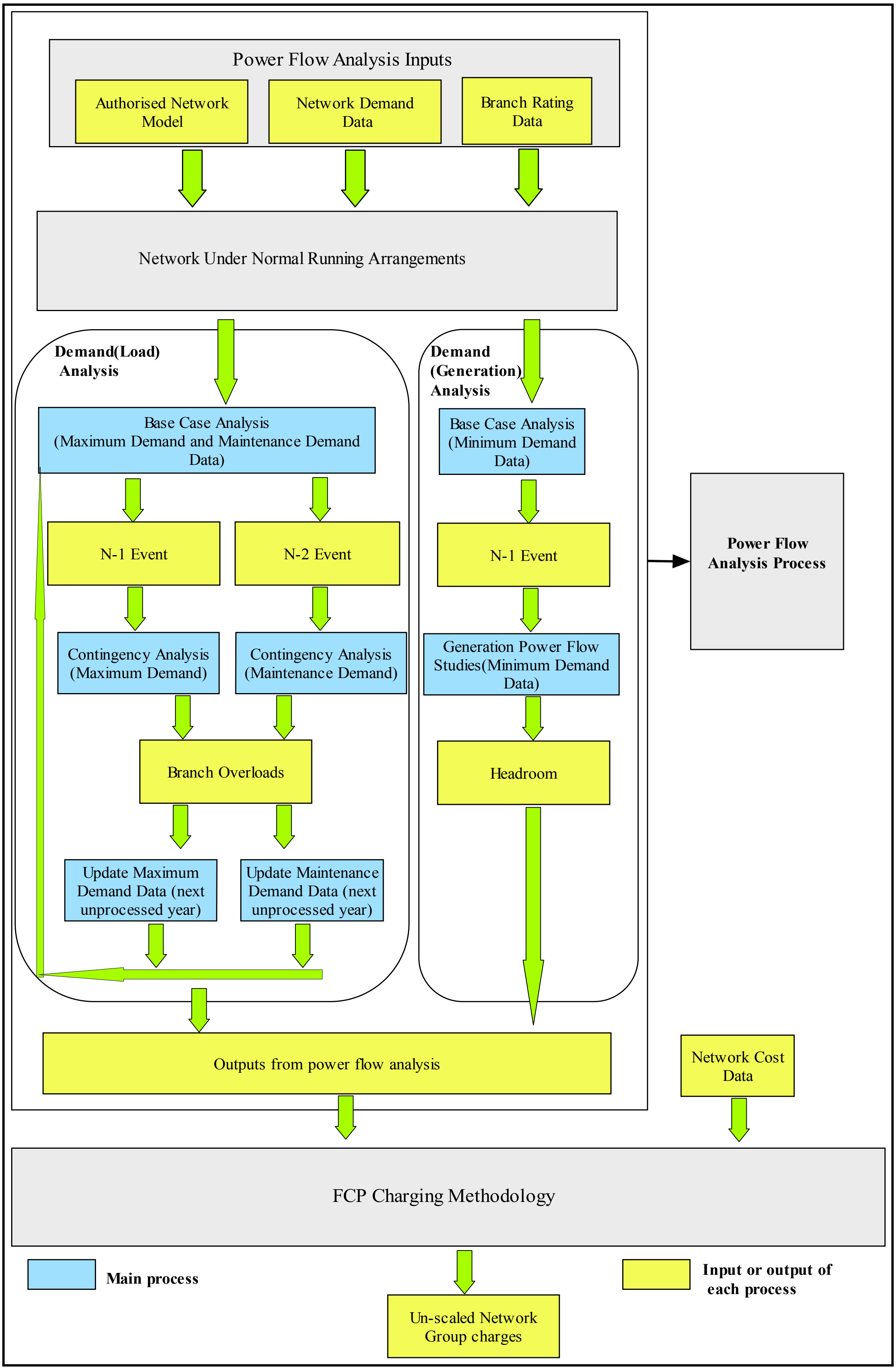
7.1 This section 7 describes the power flow analysis undertaken for pricing purposes. The purpose of power flow analysis is to determine when overloads occur on the Authorised Network Model caused by forecast changes in demand (load) and the addition of generation in each Network Group using Contingency Analysis. Each overloaded chargeable Branch will then in turn be given a reinforcement cost which will be used in the calculation of Network Group incremental charges using either the FCP_{load} formula or the $FCP_{generation}$ formula as shown in section 9 below (Calculation of Network Group incremental charges). The power flow analysis consists of two processes namely:

(a) Demand (Load) Analysis; and

(b) Demand (Generation) Analysis.

7.2 The two processes are performed separately which results in two Network Group incremental charges - demand (load) and another for demand (generation). Figure 10 shows a flow chart for the FCP methodology showing the overall processes and stages.

Figure 10 - Flowchart of the FCP pricing model.



Demand (Load) Analysis

7.3 This section examines the processes for identifying overloads and their respective timings by analysing the Authorised Network Model in succession over a 10-year period starting from the Regulatory Year the Use of System Charges are being calculated for. During this analysis only changes in demand (load) are modelled over the 10-year period.

Contingency Analysis

7.4 In line with planning standards for network security[3] Contingency Analysis is undertaken to identify the assets in each Network Group that will require reinforcement; this is achieved using AC load flow studies. The objective of the Contingency Analysis is to identify the Branches that require reinforcement and to determine the time (years) to reinforcement.

7.5 The Contingency Analysis is based on all credible outages that could affect the DNO Party's Distribution System. Both N-1 Events and where necessary, N-2 Events are modelled and the consequential network actions required to meet the security of supply requirements of ER P2/6 and the agreed level of security of supply to individual customers. For example, where appropriate, it may include constraints in distributed generation output, customer demand reductions, automatic switching schemes and manual switching. Such switching operations may include the transfer of demand or generation, as appropriate. For the N-1 Contingencies the model is set up using the Maximum Demand Data and appropriate Branch Ratings. For the N-2 Contingencies the N-2 Event is assumed to take place at the same time as a planned outage and therefore the Maintenance Demand Data and appropriate Branch Ratings are used. Only N-2 Events applicable to ER P2/6 demand class E[4] shall be considered within the Contingency Analysis, where the assessment of demand class is performed based upon the in the Regulatory Year for which the Use of System Charges are being calculated.

7.6 The N-1 and N-2 Contingency Analyses are repeated for each year of the specified 10 year planning period as shown in Figure 11. The timing for each overloaded Branch is determined from these analyses as described in Figure 11 (see Demand (Load) Analysis block). The overloaded Branches are identified by running the appropriate N-1 or N-2 Contingency Analyses on the networks populated by Maximum Demand Data or Maintenance Demand Data, respectively. If any of these two analyses cause a Branch overload for the considered year *u*, the time to reinforcement of the Branch is set to $Y=u$. If a Branch overload is

[3] Network security is a licence condition embodied in ER P 2/6

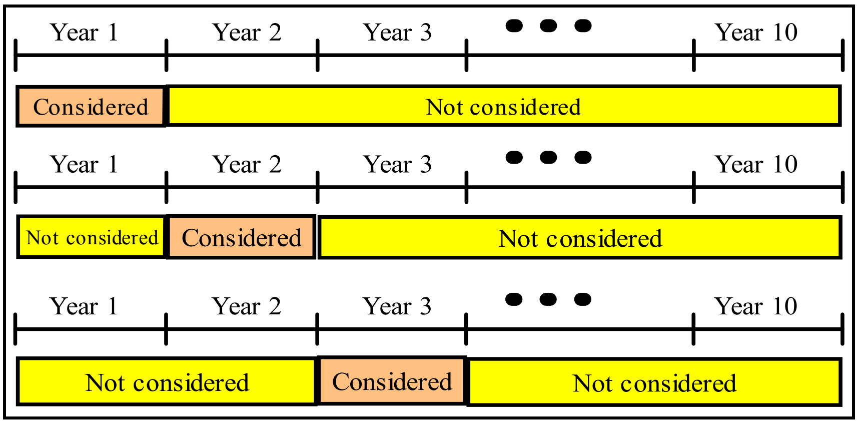
[4] ER P2/6 specifies the normal level of system security for distribution networks, classified in ranges of group demand. ER P2/6 Class E specifies the security of supply requirements where the group demand is classified as over 300MW and up to 1500MW

identified in both analyses the time to reinforcement is set to the earliest year the overload is found.

7.7 As the load flow analysis progresses through the 10-year planning period the same reinforcements will be identified and to avoid double counting of reinforcements only new Branch reinforcements each year are considered. It should be noted that the network model is static and hence not updated if a reinforcement is required.

7.8 The outputs from the Contingency Analysis will include all EHV network Branches which are overloaded, which Network Group they belong to, the time at which they were overloaded and the demand (load) that causes the overload.

Figure 11 - Reinforcements considered over the 10 year planning period.



Demand (Generation) Analysis

7.9 This section examines the processes for identifying generation related reinforcement in the model for the 10-year period.

Test Size Generators

7.10 Due to the non uniform growth of generation on the network the Demand (Generation) Analysis is based on the identification of reinforcements that would be required to accommodate the connection of new, 'typically'-sized generators within a Network Group. This is based upon a probabilistic approach assuming a notional Test Size Generator (TSG) attaches at a given location within a Network Group within the 10-year period.

7.11 The TSG is considered to be the largest 'likely' generator that could connect to the network at some point over the study period. Application of this size of TSG provides a suitable measure of the stress to the network introduced by any likely future generators and enables any associated reinforcements to be identified. Multiple locations within each Network Group are tested by the application of a TSG, each in turn. Two different types of TSG are used in the testing of each network group – ‘Substation’ TSGs and ‘Circuit’ TSGs - and are applied to different types of location within the Network Group.

7.12 A ‘Substation’ TSG shall be installed at the lower voltage of each ‘Source’ Substation within a Network Group. A ‘Source’ Substation is a substation in a Network Group that transforms down, from a higher voltage Network Group, to the voltage of the network associated with the Network Group e.g. in considering the application of ‘Substation’ TSGs within a 132/33kV BSP network group, ‘Substation’ TSGs are applied at the 33kV bars of each 132/33kV source substation (i.e. BSP) associated with the Network Group.

7.13 A Circuit TSG shall be installed at all of the following locations:

(a) the lower voltage busbars of substations that transform from the Network Group under test to lower voltage Network Groups. For example, the ‘Circuit’ TSG is applied to the lower voltage busbars of Primary Substations connected to a particular BSP Group, to identify the reinforcements within the BSP Network Group); and

(b) the Exit/Entry Point of EDCM Connectees (generation or demand) connected within the Network Group.

7.14 Different sizes are used for ‘Substation’ and ‘Circuit’ TSGs, reflecting the different output that ‘typical’ generators would be expected to have, where connecting to such locations.

Sizing Principles

7.15 The guiding principle in sizing the TSG is that no charge should be levied if the majority of likely generation sizes would not trigger reinforcement. The size of the TSG is taken to be the 85th percentile of existing and ‘customer accepted’ generation schemes connected to the DNO Party’s Distribution System at the voltage level the TSG is attached to. This approach effectively excludes the upper tail of sample, thereby ensuring that a few large generators that do not represent a ‘likely’ new generation scheme will not greatly influence the size of the TSG and lead to the imposition of incremental charges which would not be required for the majority of generators that may connect in the future.

7.16 It is considered that the use of non-parametric methods, i.e. using a percentile rather than a standard deviation, is a more robust statistical method since the distribution of generation sizes is unknown (in particular, it is unlikely to be normal).

7.17 Smaller sample sizes or very large atypical generators can impact and skew the 85th percentile

TSG size. As a result, where outliers are detected, the respective generator sample set should be aligned in order to give a greater representation of other connected generation sizes in the DNO Party's Distribution System. A separate 'Substation' TSG and 'Circuit' TSG should be separately sized, using the appropriate sample groups. This is explained below.

7.18 The resultant TSG size will be subject to a further sense check to ensure an appropriate TSG size for the generation analysis:

(a) where the size of 'Circuit' TSG is larger than the 'Substation' TSG at the same voltage level, the value derived for the 'Circuit' TSG should also be applied as the Substation TSG; and

(b) where the size of a 'Circuit' TSG at a given voltage level is zero, the size of 'Substation' TSG at the same voltage level should be applied as the 'Circuit' TSG size. Similarly where the size of the 'Substation' TSG is zero, the 'Circuit' TSG size should be applied as the size of the 'Substation' TSG.

7.19 In order to sense check the respective TSGs, they should be compared to a "TSG Threshold" to identify any abnormities which some atypical network and generation arrangements may introduce. These thresholds are:-

(a) 'Circuit' TSGs based on a 100MW[5] connection limit for 132kV, with a suitable voltage scalar used for other voltage levels; and

(b) 'Substation' TSGs based on the 'typical' firm capacity that would be expected at a substation transforming down to that voltage level.

7.20 In the event that there is no generation at a specific voltage level on the DNO Party's Distribution System a proxy TSG can be calculated taking the nearest voltage calculated TSG (calculated from actual data) and scaled by the voltage the TSG is needed. An example is given below assuming that the 33kV TSG is 25 MW and that there are no generators on the existing 22kV network but a 22kV TSG is needed. Therefore the 22kV TSG can be calculated as follows:

$$TSG_{22} = TSG_{33} \times \frac{V_{22}}{V_{33}}$$
$$TSG_{22} = 25MW \times \frac{22}{33}$$
$$TSG_{22} = 16.67MW$$

[5] This reflects the MW capacity boundary where generators have to be licensed to connect to the distribution system and comply with the Grid Code. In England and Wales this is over 100MW

7.21 The use of the voltage scalar allows a TSG size to be calculated with a similar current output considering that thermal ratings and current output are used in system design.

Sizing of Substation TSGs

7.22 The size of a Substation TSG (MW) is derived from the 85th percentile of generation schemes for “substation connected” generators only (i.e. those where the Point of Common Coupling, with other customers on the network, is at a substation that transforms down from a higher voltage to the voltage of connection of the generator (e.g. a 33kV generator is “substation connected” if it’s Point of Common Coupling is the 33kV bar of a 132/33kV substation).

Sizing of Circuit TSGs

7.23 The Circuit TSG size (MW), for each voltage level, is derived from the 85th percentile of existing and ‘customer accepted’ generation schemes for all generators at the appropriate voltage level, where the generation schemes used in the derivation are not considered as being 'substation connected'.

Generation Power Flow Studies

7.24 Once the points of connection of TSGs have been identified, and the Substation TSG and Circuit TSG sizes have been calculated, the next stage is to run the power flow analysis to determine if any Branch reinforcements are caused by the addition of the Substation and Circuit TSGs.

7.25 The Authorised Network model is populated with Minimum Demand Data for the Regulatory Year that Use of System Charges are being calculated for. All existing generator outputs are set to the Maximum Export Capacity at the corresponding Entry Points.

7.26 Network Branch Ratings are set to summer ratings, representing the most onerous seasonal condition for the assets.

7.27 Each TSG is applied, in turn, at an appropriate Node within the Authorised Network Model to test a specific Network Group, with a power output equal to its Maximum Export Capacity. Where Substation TSGs are applied, the Network Group under test is the Network Group within which the Substation TSG is connected. Where Circuit TSGs are applied, the Network Group under consideration is the higher voltage Network Group immediately upstream of the Network Group to which the Node, at which the TSG is attached, belongs.

7.28 With an appropriate TSG attached, AC power flow studies are performed to identify any requirement for reinforcement of Branches within the Network Group under consideration. These studies shall consider the power flows under Normal Running Arrangements and N-1 Contingency conditions, but not N-2 Contingency conditions. All N-1 Contingencies that affect the Network Group under consideration need to be studied. Only thermal Branch overloads are considered, with fault level and voltage regulation ignored. All reinforcements within the Network Group, under test, are identified and recorded, while overloads found outside of the Network Group under consideration are not included. The TSG is then removed and another is placed onto all untested points of connection in turn.

7.29 The example in Figure 12, Figure 13 and Figure 14 illustrate the testing of the 132, 33 and 11kV groups within a network from the application of the relevant Substation TSGs and Circuit TSGs at the appropriate network voltage level.

Figure 12 - Example of Test Size Generators application and testing at the 132kV network level

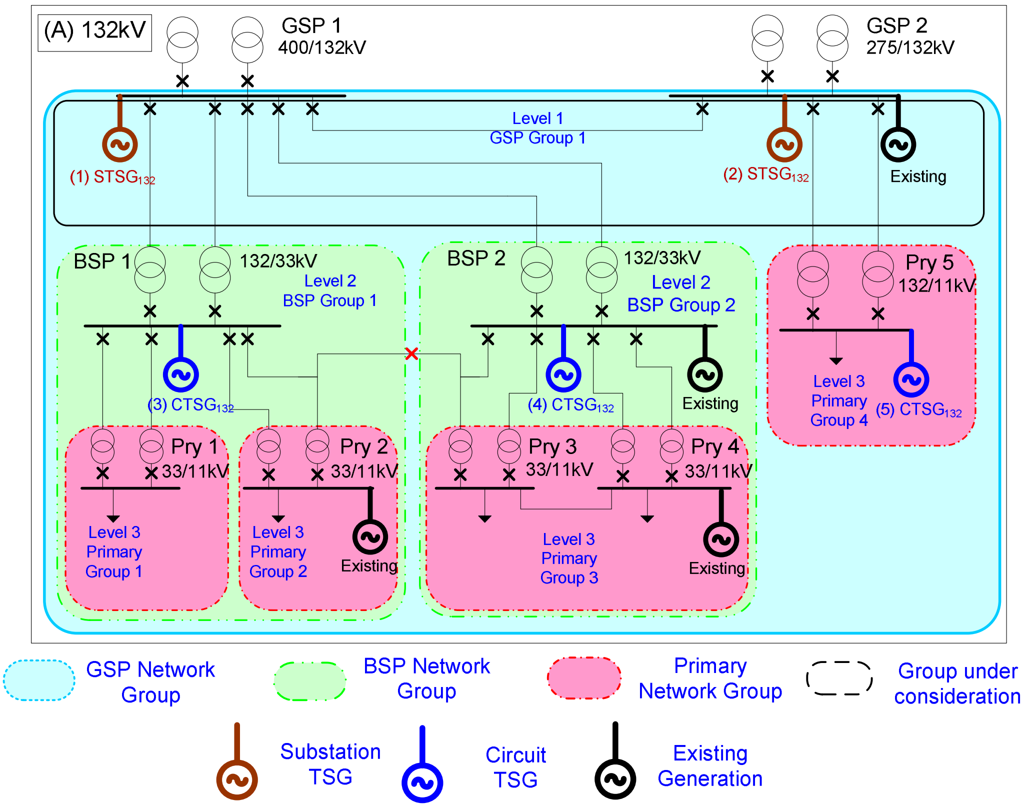


Figure 13 - Example of Test Size Generators application and testing at the 33kV network level

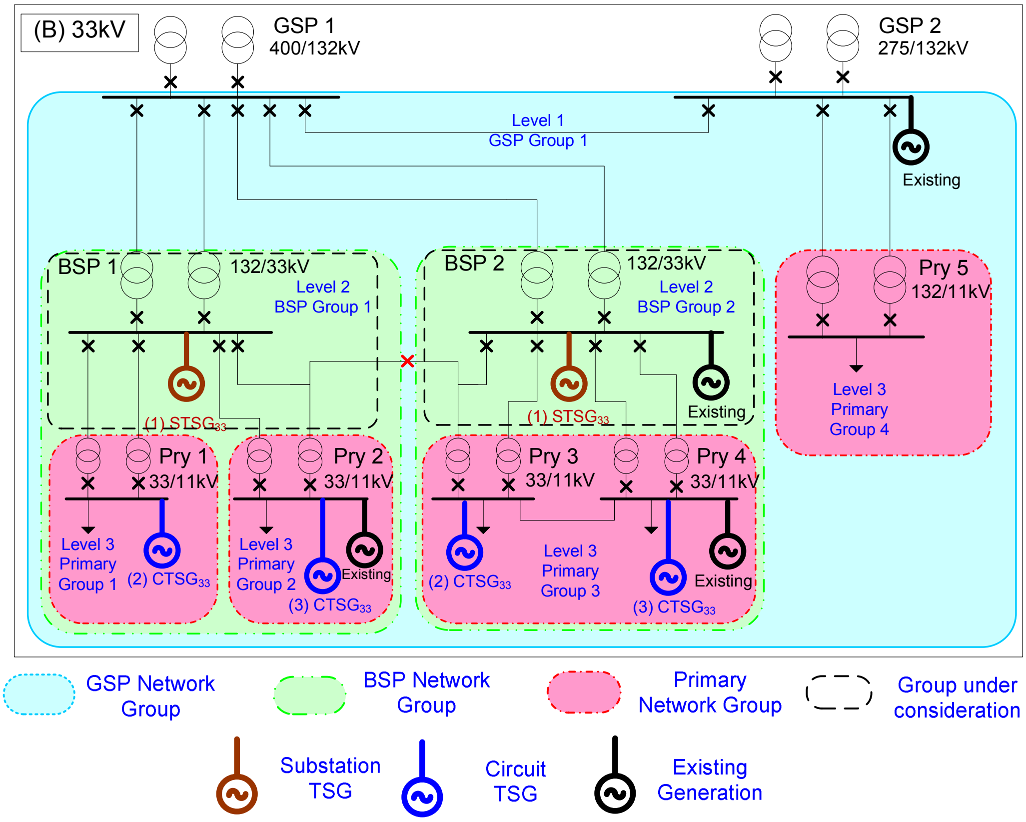
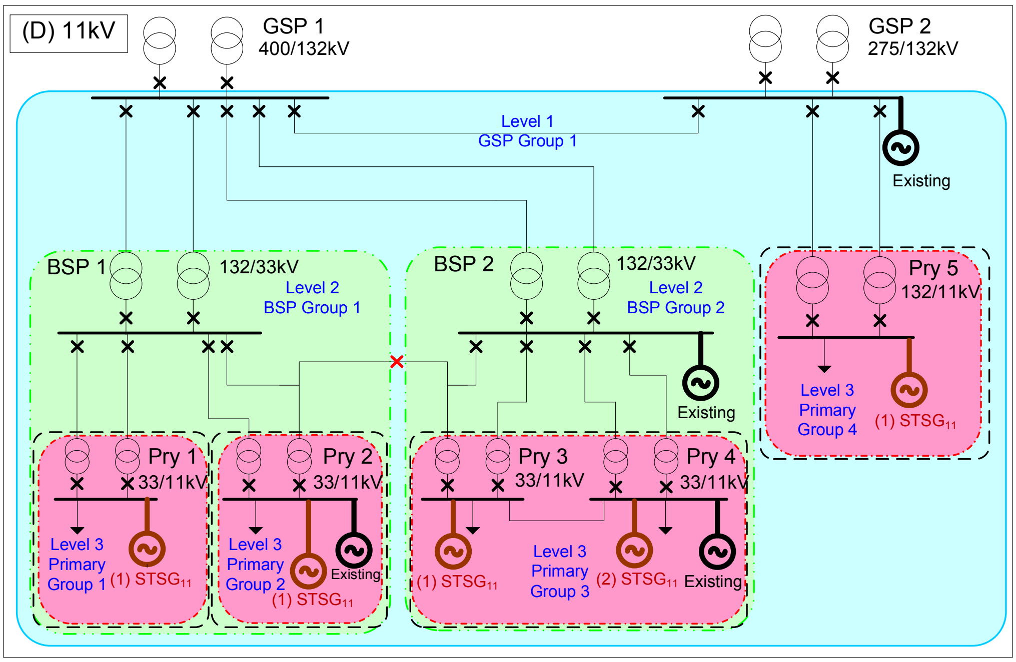


Figure 14 - Example of Test Size Generators application and testing at the 11kV network level



7.30 Figure 12 shows the application of 2 Substation 132kV TSGs, (1)$STSG_{132}$ & (2)$STSG_{132}$, and the application of 2 further Circuit 132kV TSGs, (3)$CTSG_{132}$ & (4)$CTSG_{132}$. These are applied in turn with any reinforcements as a result of their connection noted for the 132kV GSP Group 1.

7.31 Figure 13 shows the Level 2 BSP Groups 1 and 2 separately tested. For this arrangement, both groups are treated separately with the relevant Substation TSG and Circuit 33kV TSGs applied as illustrated.

7.32 Figure 14 shows the Level 3 Primary Groups 1, 2, 3, 4 and 5 separately tested. As before, the approach is the same with each group treated separately with the relevant Substation applied as illustrated.

7.33 The FCP generation charging formula given in Attachment 1 - Calculation of Network Group Load incremental charges – A Simple Example, requires the calculation of Headroom. The Headroom calculation is required to be performed for every instance that a Branch overload has been identified by the addition of a Circuit TSG or Substation TSG to the Authorised Network Model.

7.34 The Headroom calculation is performed by attaching a TSG at the same location within the Authorised Network Model that attachment of a Circuit TSG or Substation TSG identified a Branch overload. The output of the TSG is incremented, from zero, in small steps and the power flow in the Branch which had been identified as overloaded is monitored. The output of the TSG is incremented until either the Branch becomes overloaded or the capacity of the relevant Circuit TSG or Substation TSG is reached. The Headroom calculation is run with Minimum Demand Data, and with N-1 Contingencies applied. The Headroom is considered to be the maximum output (MW) from the respective TSG that does not cause the Branch in question to become overloaded. All N-1 Contingencies that affect the Network Group under consideration need to be studied.

7.35 Where the application of a Circuit TSG or Substation TSG has identified the requirement to reinforce more than one Branch, a separate value of Headroom is to be calculated for each Branch where an overload has been identified. Where a particular Branch has been identified as overloaded by application of more than one TSG, a separate value of Headroom for the Branch is determined for each different case.

7.36 The outputs from the Generation Power Flow Studies will include a reinforcement list identifying each EHV network Branch that is identified as overloaded by application of a Circuit TSG or Substation TSG, the Network Group to which the Branch belongs, the full export capacity of the relevant TSG and the Headroom. As any Branch may be overloaded by application of TSGs to more than one location, then there may be more than one entry in the reinforcement list for each Branch.

7.37 For each entry in the reinforcement list, the year to reinforcement of the Branch, caused by application of a particular Circuit TSG or Substation TSG, is determined, as shown in Attachment 1 - Calculation of Network Group Load incremental charges – A Simple Example, using both the Headroom and full export capacity of the relevant TSG. This calculation assumes that new generation shall appear at the location that the TSG was applied, growing linearly, starting from zero in the current year and reaching the full export capacity of the TSG in the final year of the planning period (i.e. year 10). The year to reinforcement is taken as being the point in time that the new generation has reached a level equal to the Headroom.

7.38 Probability factors are used within the FCP generation charging formula, given in section 9 (Calculation of Network Group incremental charges) below, to scale the reinforcement costs for each Branch, associated with the application of TSGs, by the probability of such generation actually connecting within the next 10 years. This is done in order to provide the expected cost of reinforcement for each Network Group. A probability scaling factor for each voltage level, P_v, is used in determining the probability factor appropriate for each Branch. The probability scaling factor, P_v, represents the probability of new generation connecting and is determined using the numbers and sizes of the different Circuit TSGs and Substation TSGs used in the Generation Power Flow Studies at the relevant voltage level. The method for calculating these probability scaling factors is derived by the following steps:

(a) Total new generation for the 10-year period is forecast by the DNO Party, using generation expected to connect to the existing Authorised Network Model. The total forecast is further disaggregated into individual forecasts for each of the voltage levels relevant to the DNO Party. The 10 year forecast will be reviewed annually and updated as appropriate.

(b) Each voltage level's generation forecast is divided by the total amount of new TSG generation (MW) actually attached to that voltage when studying all Network Groups of that level. For example consider a 33kV network where the export capacity size of each Substation TSG is 25MW and the export capacity size of each Circuit TSG is 20MW. If, in total, 40 Substation TSGs and 200 Circuit TSGs were applied in the Generation Power Flow Studies, the total TSG generation attached to the 33kV network is 25MW x 40 + 20MW x 200 = 5,000MW. If 5,000MW of TSG generation is attached to the 33kV network during the Generation Power Flow Studies, but only 500MW of generation is actually forecast by the DNO Party to be connected to the 33kV network over the next 10 years, then the probability of a TSG connecting to the 33kV network is taken to be 500/5,000 = 0.1. The calculated figure is taken to be the probability that a TSG will connect at that voltage level.

(c) If there is no forecast generation at a particular voltage level the same probability is used as the nearest voltage level that was used for the calculation of the proxy TSG size.

8 Calculation of reinforcement costs

8.1 The calculation of Network Group incremental charges for demand (load/generation) is based on the outputs obtained from the power flow analysis process which is discussed in the section 9 (Calculation of Network Group incremental charges) below (see Figure 10).

8.2 Using the results of the power flow analysis and reinforcement costs, Network Group incremental charges for demand (load/generation) can be calculated based on the formulae presented in section 9 (Calculation of Network Group incremental charges) below. The main principles for the calculation of reinforcement costs are given in section 8.3 (Reinforcement Cost Calculation Principles) below.

Reinforcement Cost Calculation Principles

8.3 These are general principles for the calculation of the reinforcement costs:

(a) Each branch within the Authorised Network Model should be considered as being one of three types:-

(i) Transformer Branches - which represent Branches at substations that provide transformation between different voltage levels.

(ii) Circuit Branches - which represent an interconnection (or part of an interconnection) between substations and which operate at a single voltage level.

(iii) Zero-cost Branches - these Branches exist in the network model but have zero reinforcement costs.

(b) Zero-cost Branches shall include, but not be limited to:-

(i) Branches that represent assets that are not part of the DNO Party's

Distribution System for which marginal costs are being calculated e.g. sections of the National Electricity Transmission System, adjacent Distribution Systems etc.

(ii) Branches that represent Sole Use Assets.

(iii) Branches that represent internal connections within substations, other than installed transformation (e.g. bus couplers, bus section circuit breakers etc.)

(c) The cost of reinforcement for a Branch shall be constructed from typical unit costs appropriate to the categorisation of the branch and the components represented.

(d) The typical unit costs used to derive the cost of reinforcement for a branch shall:

(i) reflect the modern equivalent asset value of reinforcing the particular asset;

(ii) include overheads directly related to the construction activity;

(iii) include building and civil engineering works, in unmade ground.

(e) A cost of reinforcement shall be allocated to each Transformer Branch and Circuit Branch taking account where possible of:

(i) the voltage of operation of the Circuit (or in the case of Transformer Branches, the voltages of transformation);

(ii) the existing mix of overhead line and underground cable within Circuit Branches;

(iii) the requirements and costs of similar historic reinforcement projects.

(f) The costs associated with substation plant and equipment (such as circuit breakers, switches, protection equipment, earthing devices etc.) shall be included within the cost of reinforcement and allocated appropriately across the Transformer Branches and Circuit Branches to which they relate.

(g) The typical unit costs used to derive the cost of reinforcement for a branch shall:

(i) reflect the modern equivalent asset value of reinforcing the particular asset;

(ii) include overheads directly related to the construction activity;

(iii) include building and civil engineering works, in unmade ground.

Branch Rating Data

8.4 Each Branch in the Authorised Network Model needs to be assigned a Branch Rating appropriate to each analysis scenario considered. Where a Branch represents a number of components (for instance, a number of sections of overhead line and/or underground cable) then the rating of that Branch is calculated by looking at the ratings of all the subcomponents and determining the lowest value. The rating of a transformer shall be the capability of the transformer to supply load at its secondary terminals.

9 Calculation of Network Group incremental charges

FCP load incremental charge

9.1 In each Network Group reinforcements within a 10-year horizon are identified. Reinforcements that are a part of lower voltage Network Groups are excluded. From Figure 78it can be seen that:

(a) In the GSP Network Group (Level 1) the Branches that are considered for reinforcement are only the EHV Branches connecting the GSPs to the BSPs, the transformers connected to the GSPs are transmission Branches and so not included in the EDCM. All of the other network Branches fall into the lower voltage Network Groups (Level 2 and Level 3).

(b) In the BSP Network Groups (Level 2) incremental charges are derived from the reinforcement costs of the BSP transformers and the outgoing Network Group Branches.

(c) In the Primary Network Groups (Level 3) incremental charges are derived from the reinforcement costs related only to the Primary transformer as the 11kV circuits are not considered in the EDCM.

9.2 The following charging function is used to derive the Network Group incremental charge (£/kVA/annum) for demand (load):

$$FCP_{load} = \sum_{j} \frac{i\left(\frac{A_j}{C_l}\right)\left(\frac{D}{C_l}\right) g_l^{\frac{2i}{\ }-1}}{1 - e^{-iT}}$$

Where:

FCP_{load} = FCP load incremental charge (£/kVA/annum)

j	=	index of Branch whose reinforcement is required in the planning period
i	=	discount rate, which is assumed to be the pre-tax cost of capital set by the Authority as part of the then most recent review of the charge restriction conditions applying under the DNO Party's Distribution Licence
A_j	=	total cost (£) of asset "j" reinforcement in the considered Network Group over 10-year period
l	=	index of the total load level at which reinforcement of Branch "j" is required
C_l	=	total demand (kVA) of the Network Group, in the Maximum Demand Scenario, in the year Y_l in which reinforcement of Branch "j" is required
D	=	total demand (kVA) in the Network Group in the first year of the 10-year horizon in the Maximum Demand scenario
g_l	=	annual average load growth rate corresponding to the year in which the reinforcement is expected to be required (see below)
T	=	10 years over which the reinforcement cost is recovered

9.3 The annual average load growth rate corresponding to the year in which the reinforcement is expected to be required generic Network Group load growth rate, g_l, is calculated by:

$$g_l = \frac{\ln\left(\frac{C_l}{D}\right)}{Y_l}$$

Where:

g_l	=	annual average load growth rate corresponding to the year in which the reinforcement is expected to be required
Y_l	=	number of years before the reinforcement of Branch "j" is required
C_l	=	total demand (kVA) of the Network Group, in the Maximum Demand Scenario, in the year Y_l in which reinforcement of Branch "j" is required
D	=	total demand (kVA) in the Network Group in the first year of the 10-year horizon in the Maximum Demand scenario

FCP generation incremental charge

9.4 The network reinforcements identified through the calculation of Headroom, for each location that a Test Size Generator is used to consider the Network Group, are used to derive £/kVA/annum Network Group incremental charges for demand (generation):

(a) GSP Network Groups (Level 1) incremental charges are derived from reinforcement costs associated with the EHV Branches connecting the GSPs to the BSPs.

(b) BSP Network Groups (Level 2) incremental charges are derived from reinforcement costs of the BSP transformers and the outgoing Network Group Branches.

(c) Primary Network Groups (Level 1) incremental charges are derived from reinforcement costs of the primary transformers.

9.5 The Network Group incremental charge for demand (generation) is calculated by spreading the estimated generation reinforcement costs across the total expected EDCM generation for the 10-year period. For a specific Network Group, the Network Group incremental charge (£/kVA/annum) for demand (generation) is calculated from the following formula:

$$FCP_{generation} = \frac{\sum_{j} P_V^j \cdot A_j \cdot e^{-iY_l}}{G_{total} + \sum_{k} G_{total}^k}$$

Where:

$FCP_{generation}$	=	FCP generation incremental charge (£/kVA/annum)
P_v^j	=	composite probability associated with Branch "j"
A_j	=	total cost (£) of Branch "j" reinforcement in the considered Network Group over 10 year period
i	=	discount rate, which is assumed to be the pre-tax cost of capital set by the Authority as part of the then most recent review of the charge restriction conditions applying under the DNO Party's Distribution Licence
Y_l	=	earliest number of years before the reinforcement of Branch "j" is required
G_{total}	=	total 10-year EDCM Generation in the considered Network Group
G^k_{total}	=	total 10-year EDCM Generation in a Network Group downstream of the considered Network
k	=	index of downstream Network Group connected to the considered Network Group

9.6 The probability factor is given by the following equation:

$$P_V = \frac{G_V}{M_{VS}S_{VS} + M_{VC}S_{VC}}$$

Where:

P_v	=	probability of new generation at voltage level "v"
G_v	=	the DNO Party's forecast new generation for voltage level "v"
M_{vs}	=	total number of Substation TSGs connected at voltage level "v" in the power flow analysis of all Network Groups
S_{vs}	=	size (capacity) of Substation TSG
M_{vc}	=	total number of Circuit TSGs connected at voltage level "v" in the power flow analysis of all Network Groups
S_{vc}	=	size (capacity) of Circuit TSG

9.7 This probability is applied to the present value of the cost of reinforcement when the overload is triggered by the installation of a single TSG. For cases in which the reinforcement of a Branch is triggered by the installation of multiple TSGs, composite probability is applied instead. This is calculated by:

$$P_V^j = 1 - (1 - P_V)^{M_S^j + M_C^j}$$

Where:

P_v^j	=	composite probability associated with asset “j”
P_v		probability of new EDCM Generation at voltage level “v”
M_s^j	=	number of Substation TSGs that cause overload of Branch “j”
M_c^j	=	number of Circuit TSGs that cause overload of Branch “j”

9.8 The present value of the cost of reinforcement of an overloaded Branch is a function of the time before which the expected reinforcement is required. The time to reinforcement is derived from:

$$Y_l = \frac{10H_l}{S_v}$$

Where:

Y_l	=	number of years before the reinforcement of Branch “j” is required.
H_l	=	TSG headroom for Branch “j”. This is the maximum output from the TSG that does not cause Branch “j” to become overloaded
l		index of TSG that causes triggers the earliest time to reinforcement of Branch “j”
S_v	=	size of the TSG at voltage level “v”. This may take the value of S_{VS} if a ‘substation’ TSG has been applied or S_{VC} if a ‘circuit’ TSG has been applied.
S_{vs}	=	Substation TSG
S_{vc}	=	Circuit TSG

9.9 Total EDCM generation expected to connect to the DNO Party’s Distribution System over the 10-year horizon period is given by:

$$G_{total} = 10(G_{existing} + G_{new})$$

Where:

G_{total}	=	total 10-year EDCM Generation connected within the considered Network Group
$G_{existing}$	=	existing EDCM Generation connected within the considered Network

		Group
G_{new}	=	new EDCM Generation connected within the considered Network Group

9.10 The annual average new EDCM Generation expected to connect to the DNO Party's Distribution System over the 10-year horizon period is given by:

$$G_{new} = 0.5 P_V (M_S S_{VS} + M_C S_{VC}),$$

Where:

G_{new}	=	new EDCM Generation connected within the considered Network Group
M_s	=	number of Substation TSGs connected to test the considered Network Group
M_c	=	number of Circuit TSGs connected to test the considered Network Group
S_{vs}	=	size (capacity) of Substation TSG
S_{vc}	=	size (capacity) of Circuit TSG

9.11 Total EDCM Generation in the Network Group under consideration over the 10-year horizon period is given by:

$$G_{total} = 10\,(G_{existing} + 0.5 P_V (M_S S_{VS} + M_C S_{VC}))$$

Where:

G_{total}	=	total 10-year EDCM Generation connected within the considered Network Group
$G_{existing}$	=	existing EDCM Generation connected within the considered Network Group
M_s	=	number of Substation TSGs connected to test the considered Network Group
M_c	=	number of Circuit TSGs connected to test the considered Network Group
S_{vs}	=	size (capacity) of Substation TSG
S_{vc}	=	size (capacity) of Circuit TSG

9.12 The year to reinforcement Y_j is used to find the present value of the reinforcement cost of Branch "j". Continuous discounting is applied in the form of the present value factor exp(-i·Y_j) where "i" is interest rate.

Hybrid groups

9.13 This scenario necessitates that a hypothetical, hybrid Network Group, which represents a composite of the 'parent' groups, is constructed for the purpose of setting incremental charges. The demand and generation incremental charges for a hybrid Network Group should be calculated by aggregating the incremental charges of all constituent Network Groups weighted by the demands supplied to the downstream Network Group.

9.14 Consider the following:

(a) a Primary Substation (Level 3) Network Group, PRY, that is supplied from two separate BSP (Level 2) Network Groups, BSP1 and BSP2;

(b) transformers T1 and T3 at PRY are supplied from BSP1 and transformer T2 is supplied from BSP2. The power flows through T1, T2 and T3 are D_{PRY}^{T1}, D_{PRY}^{T2} and D_{PRY}^{T3} under Normal Running Arrangements; and

(c) the incremental charge (Charge 1 or Charge 2) associated with Network Group BSP1 is FCP_{BSP1} and the incremental charge associated with BSP2 is FCP_{BSP2}.

9.15 The incremental charge (Charge 1 or Charge 2) for the hybrid ‘parent’ group supplying PRY is given by:

$$FCP_{hybrid} = \frac{\left(FCP_{BSP1} * \left(D_{PRY^{T1}} + D_{PRY^{T3}}\right)\right) + \left(FCP_{BSP2} * D_{PRY^{T2}}\right)}{D_{PRY^{T1}} + D_{PRY^{T2}} + D_{PRY^{T3}}}$$

Where:

FCP_{hybrid}	=	‘hybrid’ parent group incremental charge
FCP_{BSP1}	=	incremental charge associated with Network Group BSP1
D_{PRY}^{T1}	=	demand recorded at T1 at Primary Substation PRY
D_{PRY}^{T3}	=	demand recorded at T3 at Primary Substation PRY
FCP_{BSP2}	=	incremental charge associated with Network Group BSP2
D_{PRY}^{T2}	=	demand recorded at T2 at Primary Substation PRY

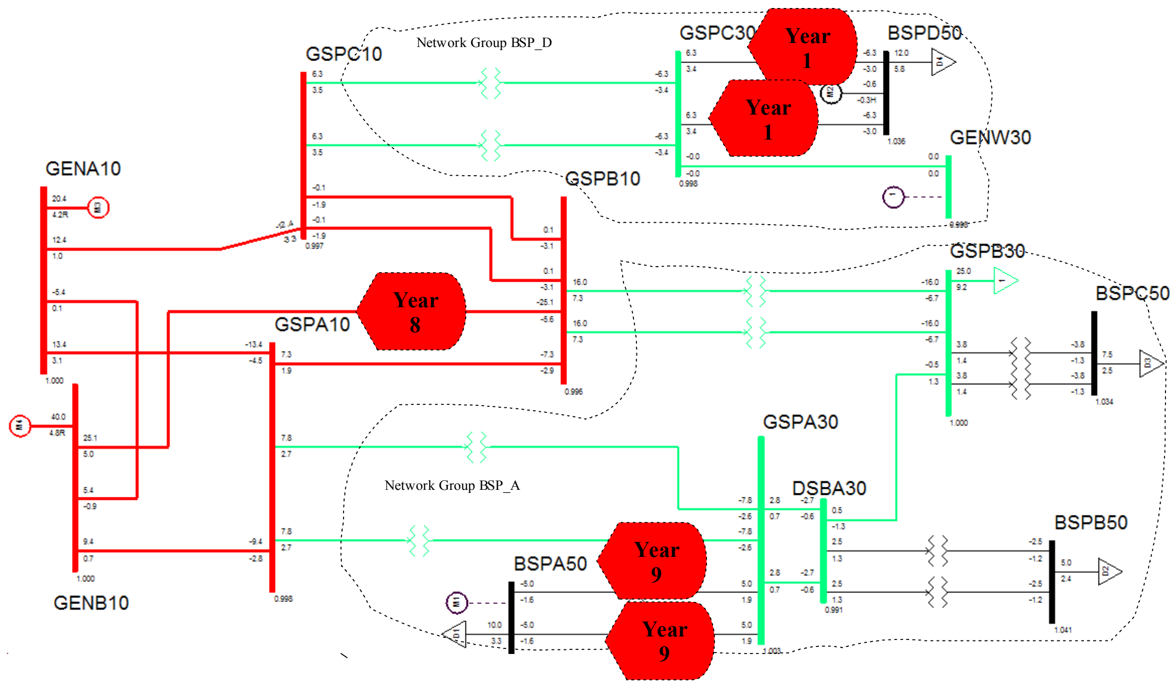
Attachment 1 - Calculation of Network Group Load incremental charges – A Simple Example

1. A small network example is shown below (Figure 15) to illustrate the calculation of Network Group incremental charges for demand (load).

2. The shown network consists of a single GSP Network Group (Level 1 shown in red) that contains two BSP Network Groups (denoted as BSP_A and BSP_D shown in green) (Level 2). For the sake of simplicity and brevity the calculation is carried out assuming that the network is split only into Level 1 and Level 2 (ignoring Level 3) Network Groups. The calculation principles described in this example can be similarly 'extended' to Level 3 Network Groups.

3. There are five reinforcements identified for this small network through a power flow analysis discussed in section 7 (Power flow analysis process) of Annex 1. These reinforcements are: a 132 kV line between 'GSPB10' and 'GENB10' and two primary transformers in each Level 2 Network Group. The required reinforcements and the year when these would be required are shown in the figure below.

Figure 15 - Example of charging by Network Groups



1 The calculation of Network Group incremental charges is summarised in

Table 12 for demand connected to 132 kV and in Table 13 for demand connected within BSP_*A* and *BSP_D*. The calculation is based on the formula given in paragraph 1.16 of the Authority's Decision Document (ref: 90/09, Annex 2):

$$FCP = i(A/C)\ (D/C)^{\uparrow}(2i/g - 1)/[(1 - e]\ ^{\uparrow}(-iT)\ ) = 0.134786 * \left(\frac{A}{C}\right)\left(\frac{D}{C}\right)^{\frac{2i}{g}-1}$$

Where:

i is a discount rate,

$T = 10$ years,

A is the Branch reinforcement cost (£),

C is demand (MVA) of the Network Group at which each reinforcement would be required,

D is initial demand (MVA) in the Network Group and

g is demand growth rate calculated from the formulae given in **Attachment 1 - Calculation of Network Group Load incremental charges – A Simple Example**, specifically $\frac{\ln\left(\frac{C}{D}\right)}{Y}$

where Y is the number of years into the future when reinforcement is required.

2 The implementation of the formula given above is described in a number of steps in Tables 6 and 7 below.

3 Both tables are split into two parts, the shaded one which contains information on:

- Network Group name;
- Network Group incremental charge for reinforcements within the Network Group;
- Network Group incremental charge for reinforcements in the parent Network Group;
- Total Network Group incremental charge;
- C and D .

4 The second part (non-shaded) is a decomposition of the Network Group incremental charge with respect to each reinforcement, where a 'reinforcement share' in the Network Group incremental charge is calculated.

5 The Network Group incremental charge for Level 1 Network Group is 3.24 £/kVA/annum due to the cost of the 132 kV reinforcement of £4,125,000.

6 The Network Group incremental charges for Level 2 consist of the corresponding incremental charge due to reinforcements identified in the Network Group (BSP_A 1.28 £/kVA/annum, BSP_D 9.18 £/kVA/annum) and the incremental charge calculated for the corresponding higher level, which is 3.24 £/kVA/annum. The combined Network Group incremental charge for BSP_A is a sum of 1.28 £/kVA and 3.24 £/kVA/annum, which is 4.52 £/kVA/annum. Similarly, for Network Group BSP_D the combined Network Group incremental charge is 12.42 £/kVA/annum.

Table 12 – Network Group incremental charge for Level 1 Network Group.

Network Group	Network Group charge[6]	Higher Level charge[6]	Combine charge[6]	Demand[MVA]	Incremental charge decomposition				
GSP	3.24	0	3.24	D=63.94 C=67.04 (Year 8)	Branch Cost - A[£]	Timing [years]	$\left(\frac{A}{C}\right)$	$\left(\frac{D}{C}\right)^{\frac{2i}{g}-1}$	Branch Share (footnote) [£/kVA/annum]
					4125000	8	61530	0.389	3.24

Table 13 - Network Group incremental charge for Level 2 Network Group.

Network Group	Network Group charge[6]	Higher Level charge[6]	Combined charge[6]	Demand [MVA]	Incremental charge decomposition				
BSP_A	1.28	3.24	4.52	D=50.6 C=52.6 (Year 9)	Branch Cost - A[£]	Timing [years]	$\left(\frac{A}{C}\right)$	$\left(\frac{D}{C}\right)^{\frac{2i}{g}-1}$	Branch Share [£/kVA/annum]
					727600	9	13832.7	0.345	0.64
					727600	9	13832.7	0.345	0.64
BSP_D	9.18	3.24	12.42	D=13.33 C=13.46 (Year 1)	Branch Cost - A[£]	Timing [years]	$\left(\frac{A}{C}\right)$	$\left(\frac{D}{C}\right)^{\frac{2i}{g}-1}$	Branch Share [£/kVA/annum]
					509200	1	37830.6	0.9	4.59
					509200	1	37830.6	0.9	4.59

[6] Network Group charge, Higher level Network Group charge and Combined Network Group charge are given in £/kVA/annum.

Attachment 2 - Calculation of Network Group Generation incremental charges – A Simple Example

1. A small network example is shown below (Figure 16) to illustrate the calculation of Network Group incremental charges for demand (generation). This network is the same as that used to illustrate the demand (load) incremental charge calculation in Attachment 1 - Calculation of Network Group Load incremental charges – A Simple Example.

2. The network consists of a single GSP Network Group (Level 1 shown in red) that contains two BSP Network Groups (denoted as BSP_A and BSP_D shown in green) (Level 2). These two BSP groups feed 4 Primary Network Groups (PRY_A – PRY_D).

3. To identify reinforcements within a network group, a power-flow analysis algorithm applies Test Size Generators (TSGs) at various locations. This is done by connecting hypothetical generation at each location in turn. The size and location of these TSGs is discussed in section 7.9 (Demand (Generation) Analysis) of Annex 1.

4. Four assets are identified as requiring reinforcement when all of the TSGs in the network have been tested. Two of these assets are flagged for reinforcement by more than one TSG. The reinforcements are shown in Figure 16 and in Table 14.

Figure 16 - Example of generation charging by Network Groups

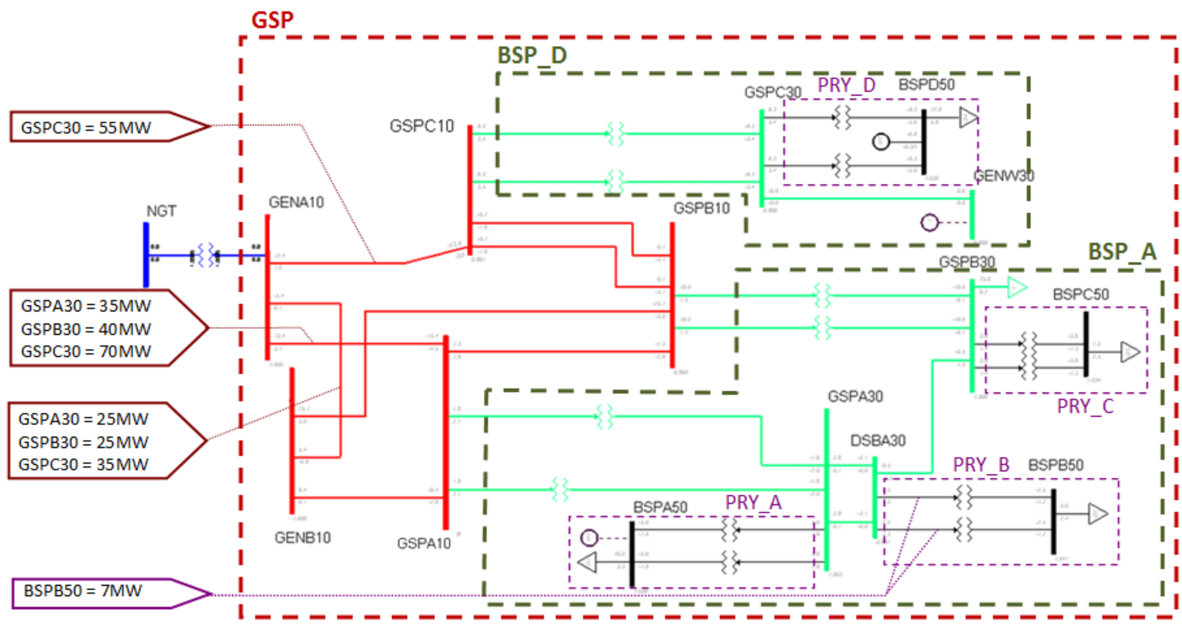


Table 14 – List of reinforcements identified during generation power flow analysis

Testing Group	TSG Location	TSG Type	TSG Size (S_v) [MW]	TSG Step [MW]	Asset From	Asset To	Overload at Step (MW)	Asset Headroom (H_j) [MW]	Timing $Y_j = 10\frac{H_j}{S_v}$ [Years]
GSP	GENA10	Source	70	5	None				
GSP	GSPA30	Circuit	70	5	GENA10	GENB10	25	20	2.857
					GENA10	GSPA10	35	30	4.286
GSP	GSPB30	Circuit	70	5	GENA10	GENB10	25	20	2.857
					GENA10	GSPA10	40	35	5.000
GSP	GSPC30	Circuit	70	5	GENA10	GENB10	35	30	4.286
					GENA10	GSPC10	55	50	7.143
					GENA10	GSPA10	70	65	9.285
BSP_A	GSPA30	Source	50	5	None				
BSP_A	GSPB30	Source	50	1	None				
BSP_A	BSPA50	Circuit	15	1	None				
BSP_A	BSPB50	Circuit	15	1	None				
BSP_A	BSPC50	Circuit	15	1	None				
BSP_D	GSPB30	Source	50	1	None				
BSP_D	BSPA50	Circuit	15	1	None				
PRY_A	BSPA50	Source	7	1	None				
PRY_B	BSPB50	Source	7	1	BSPB50	DSBA30	7	6	8.571
					BSPB50	DSBA30	7	6	8.571
PRY_C	BSPC50	Source	7	1	None				
PRY_D	BSPD50	Source	7	1	None				

The reinforcement with the earliest timing for each asset has been highlighted in Blue

1 Probability factors (P_v) are calculated for TSGs at each voltage level. These describe the probability of generation actually connecting at the TSG locations within the next 10 years. This is determined using the number and size of TSGs connected at each voltage level across the network and the total forecasted generation at that voltage level. See Table 15.

Table 15 – Calculation of Probability Factors

	Voltage [kV]	Forecasted Generation G_v [MW]	Source TSG size S_{vs} [MW]	Circuit TSG size S_{vc} [MW]	Number of Source TSGs M_{vs}	Number of Circuit TSGs M_{vc}	Probability Scaling Factor $P_V = \frac{G_V}{M_{VS}S_{VS} + M_{VC}S_{VC}}$
GSP	132 kV	250	70	70	1	3	0.8929
BSP	33 kV	200	50	15	3	4	0.9524
PRY	11 kV	26	4	-	4	-	0.9286

2 Table 16 details the existing and expected demand (generation) connected to each network group. The new generation connected to the network group is given by the total size of TSGs used to test that network group, multiplied by the probability of these TSGs actually connecting within the 10-year period.

Table 16 – Demand (Generation) connected within each Network Group

Network Group	Upstream Network Group	Existing Generation connected within considered network group [MW]	New generation expected in 10 year period $G_{new} = 0.5P_V(M_S S_{VS} + M_C S_{VC})$ [MW]	Total 10 yr generation connected within considered network group $G_{total} = 10(G_{existing} + G_{new})$ [MW]
GSP	-	0	$M_s = 1$ $M_c = 3$ $S_{vs} = 70$ $S_{vc} = 70$ $P_v = 0.8929$ $G_{new} = 125$ MW	1250
BSP_A	GSP	0	$M_s = 2$ $M_c = 3$ $S_{vs} = 50$ $S_{vc} = 15$ $P_v = 0.9524$ $G_{new} = 69.0$ MW	690
BSP_D	GSP	8.35	$M_s = 1$ $M_c = 1$ $S_{vs} = 50$ $S_{vc} = 15$ $P_v = 0.9524$ $G_{new} = 30.95$ MW	393
PRY_1	BSP_A	1	$M_s = 1$ $M_c = 0$ $S_{vs} = 7$ $S_{vc} = 0$ $P_v = 0.9286$ $G_{new} = 3.25$ MW	42.5
PRY_2	BSP_A	0	$M_s = 1$ $M_c = 0$ $S_{vs} = 7$ $S_{vc} = 0$ $P_v = 0.9286$ $G_{new} = 3.25$ MW	32.5
PRY_3	BSP_A	0	$M_s = 1$ $M_c = 0$ $S_{vs} = 7$ $S_{vc} = 0$ $P_v = 0.9286$ $G_{new} = 3.25$ MW	32.5
PRY_4	BSP_D	0.65	$M_s = 1$ $M_c = 0$ $S_{vs} = 7$ $S_{vc} = 0$ $P_v = 0.9286$ $G_{new} = 3.25$ MW	39

3 Where reinforcement of a single asset has been identified by more than one TSG, the reinforcement with the earliest timing is selected. Discount rate i=5.6% has been used for this example.

Table 17 – Network Group incremental charge for Level 1 Network Group

Network Group	Network Group charge [£/kVA/annum]	Expected Generation $G_{total} + \sum_k G_{total}^k$ [MVA]	Incremental charge decomposition

GSP	7.435	2480	Branch Cost A_j [£]	Timing Y_j [yrs]	$P_V^j = 1-(1-P_V)^{M_S^j+M_C^j}$		Asset Present Value $P_V^j \cdot A_j \cdot e^{-iY_l}$	Branch Share [£/kVA/annum]
					M_s+M_c	P_v		
			8250000	2.857	3	0.99877	7021539	2.831
			8250000	4.286	3	0.99877	6481698	2.614
			8250000	7.143	1	0.89286	4937625	1.990

Table 18 – Network Group incremental charge for Level 2 Network Group

Network Group	Upstream GSP Network Group charge [£/kVA/annum]	Network Group charge [£/kVA/annum]	Expected Generation $G_{total}+\sum_k G_{total}^k$ [MVA]	Incremental charge decomposition					
BSP_A	7.435	0.00	797.5	Branch Cost A_j [£]	Timing Y_j [yrs]	$P_V^j = 1-(1-P_V)^{M_S^j+M_C^j}$		Asset Present Value $P_V^j \cdot A_j \cdot e^{-iY_l}$	Branch Share [£/kVA/annum]
						M_s+M_c	P_v		
				None					
BSP_D	7.435	0.00	432	Branch Cost A_j [£]	Timing Y_j [yrs]	$P_V^j = 1-(1-P_V)^{M_S^j+M_C^j}$		Asset Present Value $P_V^j \cdot A_j \cdot e^{-iY_l}$	Branch Share [£/kVA/annum]
						M_s+M_c	P_v		
				None					

Table 19 – Network Group incremental charge for Level 3 Network Groups

Network Group	Upstream GSP Network Group charge [£/kVA /annum]	Upstream BSP Network Group charge [£/kVA /annum]	Network Group charge [£/kVA /annum]	Expected Generation $G_{total}+\sum_k G_{total}^k$ [MVA]	Incremental charge decomposition $P_V^j = 1-(1-P_V)^{M_S^j+M_C^j}$					
PRY_A	7.435	0.00	0.00	42.5	Branch Cost A_j [£]	Timing Y_j [yrs]	$M_S^j + M_C^j$	P_V^j	Asset Present Value	Branch Share [£/kVA /annum]
					None					

PRY_B	7.435	0.00	15.028	32.5	Branch Cost A_j [£]	Timing Y_j [yrs]	$M_S^j + M_C^j$	P_V^j	Asset Present Value	Branch Share [£/kVA /annum]
					425000	8.571	1	0.92857	244198	7.514
					425000	8.571	1	0.92857	244198	7.514
PRY_C	7.435	0.00	0.00	32.5	Branch Cost A_j [£]	Timing Y_j [yrs]	$M_S^j + M_C^j$	P_V^j	Asset Present Value	Branch Share [£/kVA /annum]
					None					
PRY_D	7.435	0.00	0.00	39	Branch Cost A_j [£]	Timing Y_j [yrs]	$M_S^j + M_C^j$	P_V^j	Asset Present Value	Branch Share [£/kVA /annum]
					None					

Attachment 3 - Output Results

1. The final outputs of the work discussed in this document are Network Group incremental charges for demand (load) and demand (generation). These are not however the final Use of System Charges and further calculations under EDCM are required to derive the final Use of System Charges.

2. The output data listed in the table below are the minimum necessary for the calculation of the final EDCM Customer Use of System Charges. To 'link' Network Groups and Nodes representing demand (load/generation) additional 'mapping' tables might be required.

3. It should be pointed out that the other information used to derive the output data will be retained for the interests of transparency.

Table 20 – Output information required to calculate final EDCM Use of System Charge.

Item	Item Name	Details
1	Network Group ID	Unique identifier of the Network Group
2	Charge 1: Demand (load) Use of System Charge (£/kVA/annum)	Network Group incremental charge for demand (load)
3	Charge 2: Demand (generation) Use of System Charge (£/kVA/annum)	Network Group incremental charge for demand (generation)
4	Parent ID	Identifier of the higher voltage Network Group immediately associated with the Network Group described by Item 1[7]
5	Active Power (kW) of Demand (Load) for Maximum Demand Scenario.	The total kW demand (load) connected to the Network Group (negative value) in the Maximum Demand Scenario
6	Reactive Power (kVAr) of Demand (Load) for Maximum Demand Scenario	The total kVAr demand (load) connected to the Network Group in the Maximum Demand Scenario[8]
7	Active Power (kW) of Demand (Load) for Minimum Demand Scenario	The total kW demand (load) connected to the Network Group (negative value) in the Minimum Demand Scenario
8	Reactive Power (kVAr) of Demand	The total kVAr demand (load) connected to the

[7] Where there is no higher voltage Network Group associated with the Network Group described by Item 1 (i.e. it is a GSP level Network Group), then the Parent ID field should be left blank.

[8] Where the current calculated for demand lags its voltage the reactive power shall be allocated the same sign as the active power. Where the current calculated for demand leads its voltage the reactive power shall be allocated the opposite sign to the active power.

	(Load) for Minimum Demand Scenario	Network Group in the Minimum Demand Scenario[8]

9	Active Power (kW) of Demand (Generation) for Maximum Demand Scenario	The total kW demand (generation) connected to the Network Group (positive value) in the Maximum Demand Scenario
10	Reactive Power (kVAr) of Demand (Generation) for Maximum Demand Scenario	The total kVAr demand (generation) connected to the Network Group in the Maximum Demand Scenario[8]
11	Active Power (kW) of Demand (Generation) for Minimum Demand Scenario	The total kW demand (generation) connected to the Network Group (positive value) in the Minimum Demand Scenario
12	Reactive Power (kVAr) of Demand (Generation) for Minimum Demand Scenario	The total kVAr demand (generation) connected to the Network Group in the Minimum Demand Scenario[8]

1 The demand (load) information that is provided as part of the output information (Items 5 to 8) shall be determined by summation of the demands (load) modelled at all Nodes within the Network Group and any associated lower voltage Network Group(s).

2 The demand (generation) information that is provided as part of the output information (Items 9 to 12) shall be determined by summation of the demands (generation) modelled at all Nodes within the Network Group and any associated lower voltage Network Group(s).

SCHEDULE 17 – EHV DISTRIBUTION CHARGING METHODOLOGY (FCP MODEL)

Annex 2 - Derivation of FCP charging formulae

The basis of the Forward Cost Pricing (FCP) methodology for both demand and generation is to set incremental charges so as to recover the expected reinforcement costs from the contributing demand or generation over the 10-year period prior to the forecast time of reinforcement. The revenue is assumed to be invested at the discount rate. Costs and incremental charges are determined for each Network Group separately. The charging formulae below are first derived for the reinforcement of a single asset (Branch). The final incremental charge rates result from the reinforcement costs of several assets, the cost being apportioned between the Network Group in which the reinforcement is forecast and the Network Groups at lower voltage levels connected to this Network Group.

Demand charging formula

Consider an asset subject to a current demand *D* in kVA where *D* grows continuously at a rate of *g*:

$$D(t) = D \cdot exp(g \cdot t). \qquad (1)$$

Suppose reinforcement would be required when the demand reaches a capacity of *C* (kVA), i.e. *D(t)=C*. Then the time *t* till reinforcement is required is given by:

$$t = ln(C/D)/g. \qquad (2)$$

Assume a discount rate of *i*, then applying the discount rate continuously (rather than in annual increments) to asset cost *A* gives a present value of the asset of:

$$PV = A \cdot exp(-i \cdot t). \qquad (3)$$

The marginal change in *PV* with respect to the demand *D* is given by differentiating expression (3), applying chain rule and using expression (2):

$$\frac{dPV}{dD} = \frac{dPV}{dt}\frac{dt}{dD} = -i \cdot A \cdot exp(-i \cdot t) \cdot \left[\frac{1}{g(C/D)}(-CD^{-2}) \right] = (i/g)(A/D)exp(-i \cdot t). \qquad (4)$$

To obtain an annual rate (£/kVA/annum) the marginal charge in £/kVA needs to be annuitised. There is no unique way of calculating the annuity factor as new payments are calculated each year. One solution is to assume NPV approach, that is, apply continuous discounting factor, and spread the incremental charge over the total time T between reinforcements (during which reinforcement incremental charges may be levied). The “annuity factor” α is then calculated as:

$$\alpha = exp(-i \cdot t)/T, \tag{5}$$

and the annuitised marginal charge is obtained by multiplying (4) and (5):

$$p(t) = (i/g)(A/D)exp(-2i \cdot t)/T \;\; £/kVA/annum. \tag{6}$$

The basic principle of the FCP approach is to ensure that the total revenue recovered over the 10 year period prior to reinforcement is equal to the cost of reinforcement. The total recovered revenue is calculated by multiplying the annuitised marginal charge by demand and revaluing to the time of reinforcement (i.e. applying the continuous “future value” factor):

$$\int_{0}^{T=10} p(t) \cdot D \cdot exp(it)dt, \tag{7.1}$$

which gives upon substitution of expression (6):

$$\int_{0}^{T=10} (i/g)(A/D)exp(-2i \cdot t)/T \cdot D \cdot exp(it)dt = \frac{A}{gT}\left[1 - exp(-10i)\right]. \tag{7.2}$$

The total recovered cost (7.2) shall be equal to asset cost A, so the marginal charge (6) needs to be scaled by factor *[1-exp(-10i)]/gT* first and then time t from expression (2) substituted giving the FCP demand formula:

$$FCP_{load} = i(A/D)exp(-2it)/[1-exp(-10i)] = i(A/D)exp[-2i \cdot ln(C/D)^{1/g}]/[1-exp(-10i)] = \\ i(A/C)(D/C)^{2i/g-1}/[1-exp(-10i)] \;\; £/kVA/annum. \tag{8}$$

In applying this formula to a reinforcement within a Network Group, C refers to the total kVA within the Network Group at which reinforcement would be required and similarly D refers to the current total kVA within the Network Group across which the cost is shared.

Each Network Group is studied over the planning period of 10 years and several reinforcements are likely to be required. The demand charging formula can then be written for the Network Group as:

$$FCP_{load} = \sum_{j} i\left(\frac{A_j}{C_l}\right)\left(\frac{D}{C_l}\right)^{\frac{2i}{g_l}-1} /(1-e^{-iT}) \;\; £/kVA/annum, \tag{9}$$

where:

j	is index of branch asset whose reinforcement is required in the planning period;
i	is the discount rate, which is assumed to be the pre-tax cost of capital set by the Authority as part of the then most recent review of the charge restriction conditions applying under the DNO Party's Distribution Licence;
A_j	is the total cost (£) of asset j reinforcement in the considered Network Group;
l	is index of the total load level at which reinforcement of asset j is required;
C_l	is total demand (kVA) of the Network Group in the year Y_l in which reinforcement of asset j is required;
D	is initial total demand (kVA) in the Network Group;
g_l	is demand growth rate calculated from $\frac{ln(C_l / D)}{Y_l}$ where Y_l is the number of years into the future when reinforcement of asset j is required;
T	is the 10 year period over which the reinforcement cost is recovered.

Generation charging formula

Generation charging under FCP methodology is done for each Network Group in turn. The essential concept is to find the ***expected*** total discounted reinforcement cost in the Network Group and then divide it by the ***expected*** total new and existing generation in the same Network Group. The concept of expectation is introduced to model uncertainty surrounding new generation, which is represented as new additional discrete units rather than annual increase of existing generation.

Expected new generation is calculated using the probability of new generation connecting. The probability is derived for each voltage separately as the ratio of the voltage level's forecast new generation and the total amount of new generation (MW) actually attached to that level in the test-size generator power flow analysis. In mathematical terms:

$$P_V = \frac{G_V}{M_{VS} S_{VS} + M_{VC} S_{VC}}, \qquad (10)$$

where:

P_V	is probability of new generation connecting at voltage level v;
G_V	is company specific forecast new generation for voltage level v;
M_{VS}	is total number of "substation" test-size generators connected at voltage level v in the power flow analysis of all Network Groups;
S_{VS}	is size (capacity) of "substation" test-size generator;
M_{VC}	is total number of "circuit" test-size generators connected at voltage level v in the power flow analysis of all Network Groups;
S_{VC}	is size (capacity) of "circuit" test-size generator.

Probability P_V shall be used to obtain expected reinforcement cost if the reinforcement of a branch asset is required within a single test-size generator powerflow study. However, there may be cases whereby a single reinforcement is required by several test-size generators, some of which are "substation" and some are "circuit". Then, composite probability needs to be associated with the corresponding asset cost:

$$P_V^j = 1 - (1 - P_V)^{M_S^j + M_C^j}, \tag{11}$$

where:

P_V^j is composite probability associated with asset j reinforcement cost;
M_S^j is number of "substation" test-size generators that require reinforcement of asset j;
M_C^j is number of "circuit" test-size generators that require reinforcement of asset j.

The expected total discounted reinforcement cost in the Network Group is the sum of individual NPV reinforcement costs multiplied by composite probability P_V^j:

$$\overline{Cost} = \sum_j P_V^j \cdot A_j \cdot e^{-iY_j}, \tag{12}$$

where A_j is reinforcement cost of asset j, Y_j is year when the reinforcement is required and $exp(-iY_j)$ is continuous discounting factor.

To calculate expected new generation, it is assumed that there is an equal probability of generation connecting in each of the 10 years, hence the probability of connection in each year is $P_V/10$. It is further assumed that there is a *linear* increase of new generation form zero in the current year to the full capacity in the last year of the planning period, so the average new generation expected to connect in the considered Network Group is:

$$\overline{G}_{new} = 0.5 P_V (M_S S_{VS} + M_C S_{VC}), \tag{13}$$

where:

M_S is number of "substation" test-size generators connected to the considered Network Group;

M_C is number of "circuit" test-size generators connected to the considered Network Group.

The expected total new and existing generation in the considered Network Group over the 10-year period is:

$$\overline{G}_{total} = 10[G + 0.5 P_V (M_S S_{VS} + M_C S_{VC})], \tag{14}$$

where G is the initial generation level in the considered Network Group. In a similar way, the expected total generation in any Network Group k that is downstream of the considered Network Group is:

$$\overline{G}^k_{total} = 10[G^k + 0.5 P_V^k (M_S^k S_{VS}^k + M_C^k S_{VC}^k)]. \tag{15}$$

Finally, the FCP generation charging formula is derived by dividing the expected total discounted reinforcement cost in the considered Network Group by the expected total generation in the considered and all downstream Network Groups:

$$FCP_{generation} = \sum_j (P_V^j \cdot A_j \cdot e^{-iY_j}) / [\overline{G}_{total} + \sum_k \overline{G}_{total}^{k}] \quad £ / kVA / annum \tag{16}$$