DCP328 – Legal Drafting

Use of System charging for private networks with competition in supply

Solution 1 plus 5A

Charging the boundary supplier for Difference Metering installations and embedded suppliers for fully settled installations

Add new definitions in Clause 1

Difference Metering	means an arrangement defined in the BSC (BSCP514) for the purposes of Settlement, whereby the flows of electricity measured by metering equipment embedded within a Licence Exempt System are deducted from the flows of electricity measured by the metering equipment at the Entry Point or Exit Point by which electricity flows from or to that Licence Exempt System.
Licence Exempt System	means an electricity distribution system that is not owned or operated by a DNO/IDNO Party.
Non-Settlement MPAN	means a 13-digit reference number for a Metering Point at an Entry Point or Exit Point, in the same format as an MPAN, which reference number is only to be used for the purposes described in this Agreement.
Meter Timeswitch Code	has the meaning given to that term in Data Transfer Catalogue (J0220).

Add a new Clause 29.5A

29.5A The following provisions shall apply in the case of an Entry Point or Exit Point on the Company's Distribution System that is subject to Difference Metering:

29.5A.1 the User shall ensure that the MPAN for the Metering Point at that Entry Point or Exit Point has Meter Timeswitch Code 996 applied to it by MPAS;

29.5A.2 the Supplier Party that is registered under the MRA in respect of an MPAN for metering equipment embedded within that Licence Exempt System shall ensure that such MPAN has Meter Timeswitch Code 997 applied to it by MPAS;

29.5A.3 the Company shall ensure that MPAS identifies the relevant Licence Exempt System for the data item 'Metering Point Address Line 1' (as described in the Data Transfer Catalogue) for each of the MPANs referred to in Clauses 29.5A.1 and 29.5A.2;

29.5A.4 the Company shall procure that the User is provided with a Non-Settlement MPAN for the Metering Point at that Entry Point or Exit Point;

29.5A.5 in addition to the Metering Data to be provided in respect of that Entry Point or Exit Point under Clause 29.4, the User shall (without charge) provide (or ensure that its BSC Party Agent provides) the Company with the metering data the User would have been obliged to procure the provision of in respect of that Entry Point or Exit Point under the BSC if Difference Metering did not apply, using the Data Transfer Catalogue D0036 or D0275 (as specified by the Company) and quoting the Non-Settlement MPAN (instead of the actual MPAN);

29.5A.6 the User shall ensure that the data referred to in Clause 29.5A.5 is provided to the Company in the same timescales as would have applied under the BSC if Difference Metering did not apply; and

29.5A.7 the Supplier Party referred to in Clause 29.5A.2 agrees that the User may receive and manipulate the Metering Data relating to consumption by the

Supplier Party's Customers connected to the Licence Exempt System in order to comply with the User's obligations under Clause 29.5A.5 and for the purpose of matters provided for or envisaged by its Supply Licence.

Add a new Clause 29.5B

29.5B Notwithstanding Clause 15.3, it is agreed that Clause 29.5A.2 creates binding obligations between the Company and the Supplier Party referred to in that Clause, and that Clause 29.5A.7 creates binding obligations between the User and the Supplier Party referred to in that Clause.

SCHEDULE 16 – COMMON DISTRIBUTION CHARGING METHODOLOGY

Introduction

This Schedule 16, version 10.0, is to be used for the calculation of Use of System Charges which will become effective from, 01 April 2018 and remain effective until superseded by a revised version.

1. This Schedule 16 sets out the Common Distribution Charging Methodology (CDCM), which gives the methods, principles, and assumptions underpinning the calculation of Use of System Charges by each DNO Party (except where the DNO Party is acting as an LDNO).

1A. The CDCM is applicable to "Designated Properties", as defined in Standard Condition 13A (Common Distribution Charging Methodology) of the DNO Party's Distribution Licences.

Commented [EA1]: This could be problematic. Part of the definition:

"…premises or Distribution Systems… connected to the licensee's Distribution System at a voltage level of less than 22 kilovolts".

We are going to define new charges which DNOs will apply in respect of customers connected to private networks, including those with DNO to PNO boundary above 22kV. But a private network with DNO to PNO boundary above 22kV is a Designated EHV Property so the licence says its charges must be calculated under the EDCM (in the same way that LDNO charges for CDCM-like customers with DNO to LDNO boundary at EHV are calculated in the EDCM).

Commented [JL2R1]: See para 28.2 in schedule 17 & 18

2. The Schedule 16 comprises two main parts. Part 1 describes the cost allocation rules. Part 2 describes the tariff structures and their application.

3. In order to comply with this methodology statement when setting distribution Use of System Charges the DNO Party will populate and publish the CDCM model version 104 when issued by the Panel in accordance with Clause 14.5.3.

4. The glossary at the end of this Schedule 16 contains definitions of terms and acronyms used in this Schedule 16. In the case of any conflict between the defined terms and acronyms set out in this Schedule 16 (on the one hand) and the definitions and rules of interpretation set out in Clause 1 of this Agreement (on the other), the defined terms and acronyms set out in this Schedule 16 shall prevail.

5. Algebraic formulae in this Schedule 16 use square brackets to clarify the calculations. For the avoidance of doubt, these square bracketed terms form an effective part of this Schedule 16.

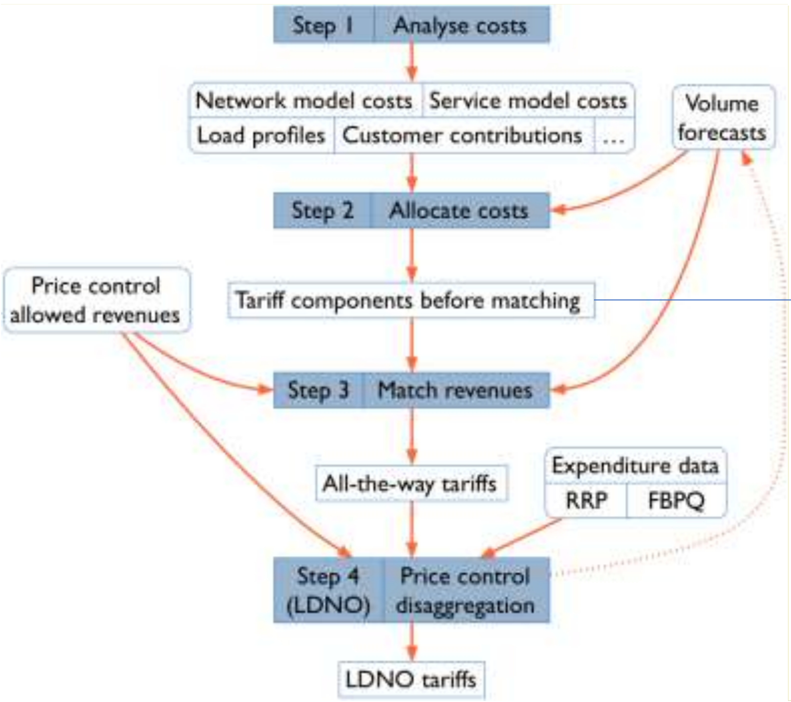
Part 1 — Cost allocation

Main steps in the allocation

6. Figure 1 gives a general overview of how the four main steps in the methodology relate to each other.

Figure 1

Overview of the main steps in the methodology



Tariffs for customers connected to Licence Exempt Systems

Commented [EA3]: These amendments will need to be made to an original version of this diagram

7. Step 1 involves the gathering of information about the network, the costs of assets and operations, the users of the network, and the forecast level of use and level of allowed revenue in the charging year.

8. Step 2 is the application of the cost allocation rules set out below. These rules are only for all-the-way tariffs and tariffs for customers connected to Licence Exempt Systems, and do not apply to LDNO tariffs.

9. Step 3 involves adjustments to the tariff components calculated in step 2 in order to match revenue recovered from the CDCM to the amount of revenue allowed under the price control conditions.

10. Step 4 uses price control condition calculations, actual expenditure data and forecast expenditure data in order to determine discount percentages, which are then applied to all-the-way tariffs in order to produce LDNO tariffs.

11. Step 4 is independent from Steps 1 to 3. In practical terms, Step 4 must be performed first, as the discount percentages are used within Step 1 to combine volume forecasts for all-the-way and portfolio tariffs into a single composite dataset for each type of end user.

Overview of the tariff components

12. Each tariff comprises some or all of the tariff components listed in table 1.

Table 1 List of tariff components

Tariff component	Unit	
One, two or three unit rates	p/kWh	
Fixed charge	p/day	
Capacity charge	p/kVA/day	
Exceeded capacity charge	p/kVA/day	Half hourly settled demand tariffs only.
Reactive power charge	p/kVArh	

13. For users that are acting as LDNOs, tariffs are portfolio tariffs with the same tariff components as the corresponding all-the-way end user tariff, excluding reactive power charges (but prices for some tariff components may be calculated as zero).

14. Each component of each tariff is rounded to the nearest value with no more than three decimal places in the case of unit rates expressed in p/kWh and reactive power unit charges expressed in p/kVArh, and with no more than two decimal places in the case of fixed and capacity charges (including exceeded capacity charges) expressed in p/MPAN/day and p/kVA/day respectively.

Step 1: Analyse costs

15. The first step of the methodology involves the determination of costs or revenue allowances for various parts of the network, and the collection of information about the relevant characteristics of network users.

Network model asset values

16. The DNO Party specifies a network model, also known as a distribution reinforcement model (DRM) or a 500 MW model, in line with the requirements of this section.

17. The network model determines the £/kW/year figure (based on simultaneous maximum load at each network level) corresponding to amortisation and return on capital for assets at the LV circuits, HV/LV, HV, EHV/HV and EHV network levels, and, in England and Wales, at the 132kV/EHV, 132kV/HV and 132kV network levels.

18. Not Used.

19. The network model consists of a costed design for an increment to the DNO Party's network.

20. At each network level, the model is sized to provide secure capacity to meet demand that, aggregated up to individual grid supply point (GSP) level, amounts to 500 MW of simultaneous maximum demand.

21. The model's design assumes a power factor of 0.95 and no embedded generation.

22. The assets included in the network model are modern equivalent assets of the kind that the DNO Party would normally install on new networks.

23. The nature, quantity and size of assets in the model is such as to meet demand and security to the DNO Party's design and planning standards, allowing for the use of standard size equipment and typical utilisation factors.

24. The proportion of assets of different types at each network level, e.g. overhead and underground circuits, reflects the mix of users and the topography in the DNO Party's Distribution Services Area.

25. The cost assumed for each asset type reflect total purchase and installation cost in the charging year, using the DNO Party's normal procurement methods.

Diversity allowances

26. For each of the 132kV (except in Scotland), EHV and HV voltage levels, the DNO Party determines a diversity allowance between the transformation level above circuits at that voltage and the transformation level below circuits at that voltage.

27. Each diversity allowance represents the extent, expressed as a percentage, to which the sum of the maximum load across all substations below would exceed the corresponding sum for substations above.

28. The DNO Party also determines a diversity allowance between the GSP Group as a whole and the individual grid supply points.

Customer contributions under current connection charging policy

29. The DNO Party estimates the extent to which the assets at each network level used by each category of users would have been expected to be covered by customer contributions if they had been constructed under the charging year's connection charging policy.

30. The DNO Party groups users into categories, by network level of supply, for the purpose of making these estimates.

31. In the case of generators, the proportions relate to the notional assets whose construction or expansion might be avoided due to the generator's offsetting of demand

on the network, and takes the same values as for a demand user at the same network level of supply.

Service model asset values

32. The DNO Party specifies a set of service models covering the range of typical dedicated assets operated for the benefit of individual HV and LV users of the network.

33. For each service model, the DNO Party estimates the number and types of connections that the model covers, and a total construction cost for the assets in the model.

34. For each tariff, the DNO Party identifies the extent to which each of the service models represents the relevant assets for an average user in that tariff.

35. A weighted average of service models is used if several service models apply to the same tariff.

36. In the case of unmetered supplies, service model assets are modelled on the basis of units delivered.

37. In the case of generation service models, the service models should reflect the additional costs of protection equipment for a typical generator in each category, for example the difference in cost between a fuse and a circuit breaker, or the cost of additional telecommunications equipment used for control purposes.

Transmission exit expenditure

38. The DNO Party prepares a forecast of expenditure on transmission exit charges in the charging year.

Other expenditure

39. The DNO Party prepares a forecast of other expenditure for the charging year, where other expenditure is defined as the sum of:

(a) 100 per cent of direct operating costs.

(b) 60 per cent of indirect costs (as defined in RRP guidance).

(c) 100 per cent of network rates.

Distribution time bands

40. The DNO Party determines five distribution time bands, labelled black, red, yellow, amber and green. The 'red', 'amber' and 'green' time bands will apply to all half hourly settled tariffs that are metered. The 'black', 'yellow' and 'green' time bands will apply to the unmetered supplies half hourly tariff.

41. Distribution time bands are defined separately for Monday-Friday and for Saturday/Sunday. In each case, time bands are defined by reference to UK clock time only, and always begin and end on the hour or half hour. There will be no constraint on either the number of hours that can be covered by each time band or whether the time band applies to all or only part of a day. The red, amber and green times bands will apply throughout the year. The black and yellow time bands can be set to apply to only part of the year, where so specified by the DNO Party.

41A. The DNO Party may only change distribution time bands with effect from 1 April and must provide a minimum of 15 months prior notice of such changes. However, where a change to distribution time bands is caused by the implementation of a change to this methodology, the requirement to provide a minimum of 15 months' notice prior notice will not apply.

41B. Notice of changes to the distribution time bands should be given in the relevant charging statement, and such notice should appear in the same paragraph of the statement as the time bands that are being changed.

Load characteristics

42. The DNO Party estimates the following load characteristics for each category of demand users:

a) A load factor, defined as the average load of a user group over the year, relative to the maximum load level of that user group. Load factors are numbers between 0 and 1.

b) A coincidence factor, defined as the expectation value of the load of a user group at the time of system simultaneous maximum load, relative to the maximum load level of that user group. Coincidence factors are numbers between 0 and 1.

c) In the case of multi-rate tariffs and non-half hourly unmetered supplies tariffs that are applied to non-half-hourly meter data or to fixed time bands that differ from the distribution time bands (if any), the estimated proportion of units recorded in each relevant time pattern regime that fall within each distribution time band.

42A. The load characteristics for non-half hourly unmetered supplies are not determined from settlement data. For each non half hourly unmetered supplies tariff the load characteristics are calculated using profile data derived for each GSP Group.

43. In determining the load characteristics of each category of demand user the DNO Party will use reasonable endeavours to analyse meter and profiling data received for the most recent 3 year period (at the time of setting charges for the relevant charging year) for which data are available in time for use in the calculation of charges. The three elements of load characteristics – Load Factors, Coincidence Factors, and the estimated proportion of units recorded in each relevant time pattern regime that fall within each distribution time band – will be calculated individually for each of the 3 years and a simple arithmetic average will be calculated to be used in tariff setting.

44. For load factors and coincidence factors in the case of non half hourly settled customer classes (except the non half hourly unmetered supplies tariffs), data adjusted for GSP Group correction factor are used.

45. For the estimated proportion of units recorded in each relevant time pattern regime that fall within each distribution time band, data are not adjusted for GSP Group correction factors.

46. Not used.

Loss adjustment factors to transmission

47. For each network level, the DNO Party determines a single loss adjustment factor to transmission relating to Exit Points from its network at that level. These loss adjustment factors should be representative of average losses at the time of system simultaneous maximum load.

Peaking probabilities

48. The DNO Party determines a peaking probability in respect of each network level and each of the distribution time bands.

49. The peaking probability represents the probability that an asset at that network level would experience maximum load during that distribution time band. In deriving peaking probabilities the DNO Party will use reasonable endeavours to use the most recent 3 year period (at the time of setting charges for the relevant charging year) for which information is available in time for use in the calculation of charges. Peaking probabilities will be derived individually for each of the 3 years and a simple arithmetic average will be calculated to be used in tariff setting.

Power factor data

50. The DNO Party determines or estimates, for each network level, the average of the ratio of reactive power flows (kVAr) to network capacity (kVA), weighted by reactive power flow.

51. If data are not available for any network level, the DNO Party uses data for the nearest network level at which they are available.

Volume forecasts

52. The DNO Party forecasts the volume chargeable to each tariff component under each tariff for the charging year.

53. The volume forecasts for portfolio tariffs are multiplied by the LDNO discount percentages determined in Step 4, and combined with the all-the-way volume forecasts

for each end user type. These combined volume forecasts are used throughout Steps 2 and 3 of the methodology.

Forecast of price control allowed revenues

54. The DNO Party prepares a forecast of allowed revenue for the charging year in accordance with the requirements of the price control conditions and in a manner which is consistent with its volume forecasts and in a format consistent with table 1 of Schedule 15.

Step 2: Allocate costs

Categories of costs

55. The cost and revenue allocation is driven by a representation of the different voltage and transformation levels in the network and by a distinction between the elements of cost related to assets and those related to operations.

56. Table 2 shows the network levels and categories of costs used in the model. In this Schedule 16, the acronym EHV refers to voltages of 22 kV and above, up to and excluding 132 kV. In the case of the Scottish Distribution Services Areas, the entries for the 132kV and 132kV/EHV network levels are zero as these voltages are part of the transmission network. LV refers to voltages below 1 kV, and HV refers to voltages of at least 1kV and less than 22kV.

Table 2 Categories of unit costs in the model

Category	Description	Unit	Levels
Network assets	Amortisation and return on capital for networks or substations at each level, excluding assets that are deemed to be covered by customer contributions. This is expressed per kW of system simultaneous maximum load.	£/kW/year	132kV 132kV/EHV EHV EHV/HV 132kV/HV HV HV/LV LV circuits
Transmission exit	Expressed per kW of system simultaneous maximum load	£/kW/year	Transmission exit
Other expenditure	Other expenditure is attributed to levels and assets in the network following the rules set out below. The part allocated to network levels is expressed per kW of system simultaneous maximum load.	£/kW/year	132kV 132kV/EHV EHV EHV/HV 132kV/HV HV HV/LV LV circuits
	The part of other expenditure allocated to assets dedicated to one customer is expressed per user for each user type.	£/year	For each type of user

Annuitisation of network model asset values

57. Capital costs that are not covered by customer contributions are converted to annual costs using a level annuity with the annuity period and rate of return set out in table 3.

Table 3 Annuity rate of return and annuity period

Parameter	Value
Annuity period	40
Annuity rate of return	Set to equal the latest pre-tax real weighted average cost of capital (CC below) for each DNO Party calculated using the following formula: CC = (Gearing Assumption x Pre-Tax Cost of Debt) + (1-Gearing Assumption)*(Post Tax Cost of Equity/(1-Corporation Tax Rate)) where: Gearing Assumption is set to the 'notional Gearing' value referred to in the ED1 Price Control Financial Handbook; Pre-Tax Cost of Debt is set to the 'cost of corporate debt' value specified in or calculated in accordance with the most recent Annual Iteration Process applicable when setting distribution Use of System Charges; Post Tax Cost of Equity is set to the 'cost of equity' value referred to in the ED1 Price Control Financial Handbook; and Corporation Tax Rate is the rate of corporation tax which is, when setting distribution Use of System Charges, expected to be applicable in respect of the regulatory year (as defined in the Distribution Licence) in which those Charges will take effect. The CC value is calculated as a percentage, and rounded to two decimal places.

Determination of unit costs from network model

58. For each network level, the DNO Party determines the flow at time of system simultaneous maximum load, measured at Exit Points from the network level, that could be accommodated by the network model on the basis of a normal mix and diversity of loads for its network.

59. The asset value and unit cost for that network level are obtained by dividing the annuitised cost of purchasing and installing the assets in the network model by this exit flow at time of system simultaneous maximum load.

[network level assets £/kW] = [assets £]/[modelled exit flow at time of system simultaneous maximum load kW]

[network level £/kW/year] = [network level assets £/kW]*[annuity factor]

60. The modelled exit flow at peak time is obtained by combining the 500 MW at GSP sizing assumption, the diversity allowance between GSP and GSP Group, and the loss adjustment factor for the relevant network level.

Allocation of other expenditure

61. Estimated load at each network level is calculated from:

a) volume forecasts for each tariff;

b) the loss adjustment factors representative of the time of system simultaneous maximum load;

c) the load characteristics for users on each tariff, used to estimate the contribution of each user category to load at the time of system simultaneous maximum load.

62. For the purposes of this calculation, a generation user is taken to make a zero contribution to load at the network level corresponding to circuits at its Entry Point, and a full negative contribution to load at all network levels above its Entry Point. For demand users, account is taken of differences between the diversity allowance in the network model and the diversity of each customer group in order to ensure that the estimated load matches the volumes subject to charges in respect of each network level.

63. For each network level covered by the network model, a notional asset value is calculated by multiplying the unit asset cost by the estimated load:

[notional asset value £] = [network level assets £/kW]*[estimated load kW]

64. For each service model, a notional asset value is calculated by multiplying the unit asset value of that service model by the extent to which each user requires that model.

65. Other expenditure (excluding transmission exit charges) is allocated between network levels in the proportion given by these notional assets.

66. The result is combined with forecast transmission exit charges to give an annual expenditure figure for each network level and for each service model. These figures are converted into unit cost using the same rules as for costs and revenues from network assets and customer assets.

Allocation of costs on the basis of contribution to system simultaneous maximum load

67. All £/kW/year unit costs and revenue are used in the calculation of yardstick charges for each tariff.

68. For demand tariffs, tariffs for demand customers connected to Licence Exempt Systems and portfolio tariffs related to demand users with a single unit rate or several unit rates and non-half hourly unmetered supplies tariffs, the contributions of each network level to the unit rate are calculated as follows:

[p/kWh from network model assets] = 100*[network level £/kW/year]*[user loss factor]/[network level loss factor]*[pseudo load coefficient]*(1 – [contribution proportion])/[days in charging year]/24

[p/kWh from operations] = 100*[transmission exit or other expenditure £/kW/year]*[user loss factor]/[network level loss factor]*[pseudo load coefficient]/[days in charging year]/24

69. These calculations are repeated for each network level.

70. In the paragraph 68 equation:

(a) the user loss factor is the loss adjustment factor to transmission for the network level at which the user is supplied;

(b) the network level loss factor is the loss adjustment factor to transmission for the network level for which costs are being attributed; and

(c) the pseudo load coefficient is calculated as follows:

i) calculate the ratio of coincidence factor to load factor that would apply if units were uniformly spread within each time band, based on the estimated proportion of units recorded in each relevant time pattern regime that fall within each distribution time band and the assumption that the time of system simultaneous maximum load is certain to be in the red or black (as appropriate) distribution time band;

ii) calculate a correction factor for each user type as the ratio of the coincidence factor to load factor, divided by the result of the calculation above;

iii) for each network level and each unit rate, derive the ratio of coincidence factor (to network asset peak) to load factor that would apply given peaking probabilities at that network level if units were uniformly spread within each time band, multiplied by the correction factor; and

iv) the result of (iii) above is the pseudo load coefficient for the network level and unit rate, save that the coefficients calculated for the non-half hourly and half hourly unmetered supplies are then aggregated to produce one value per network level.

71. For generation users, tariffs for generation users connected to Licence Exempt Systems and portfolio tariffs for generation users, no contribution to the unit rate is calculated in respect of the network level corresponding to circuits at the Entry Point, and a negative contribution to the unit rate (i.e. a credit) comes from each network level above the Entry Point. That contribution is calculated as follows:

[p/kWh from network model assets] = –100*[network level £/kW/year]*[user loss factor]/[network level loss factor]*(1 – [contribution proportion])/[days in year]/24

[p/kWh from operations] = –100*[transmission exit or other expenditure £/kW/year]*[user loss factor]/[network level loss factor]/[days in year]/24

72. Not used.

72A. An additional set of correction factors is applied to the LV Network Domestic and LV Network Non-Domestic Non-CT tariffs and the non-half-hourly-settled tariffs for profile classes 1 to 4, so as to ensure that the average charges produced by the LV Network Domestic tariff are equivalent to a volume-weighted average of the non-half-hourly-settled tariffs for profile classes 1 and 2, and the average charges produced by the LV Network Non-Domestic Non-CT tariff are equivalent to a volume-weighted average of the non-half-hourly-settled tariffs for profile classes 3 and 4.

Allocation of network costs to standing charges (fixed and capacity)

73. For demand users, other than unmetered users, standing charge factors are used to reduce unit charges and to attribute these costs or revenues to capacity charges (p/kVA/day) or fixed charges (p/day) instead.

74. The standing charge factors for demand tariffs are shown in the table below:

Tariff	EHV	EHV/HV	HV	HV/LV	LV circuits
Domestic Unrestricted					100%
Domestic Two Rate					100%
Domestic Off Peak (related MPAN)					100%
Small Non Domestic Unrestricted					100%
Small Non Domestic Two Rate					100%
Small Non Domestic Off Peak (related MPAN)					100%
LV Medium Non-Domestic					100%
LV Sub Medium Non-Domestic				100%	
HV Medium Non-Domestic	20%	100%	100%		
LV Network Domestic					100%
LV Network Non-Domestic Non-CT					100%
LV HH Metered			20%	100%	100%
LV Sub HH Metered			100%	100%	
HV HH Metered	20%	100%	100%		
NHH UMS Category A					0%
NHH UMS Category B					0%
NHH UMS Category C					0%
NHH UMS Category D					0%
LV UMS (Pseudo HH Metered)					0%

75. Where a standing charge factor is specified for the EHV/HV network level, the same standing charge factor applies to the 132kV/HV network level.

76. Where a standing charge factor is specified for the EHV network level, and where the 500 MW model includes 132kV/HV transformation, the 132kV standing charge factor is set to the EHV standing charge factor multiplied by the proportion of load going through 132kV/HV transformation.

77. For each tariff, the unit rates are reduced to take account of the allocation of costs to capacity or fixed charges. This is achieved by multiplying the cost element for each relevant network level by (1 – [standing charge factor]).

78. For each demand user type, and for each network level, the unit cost to be attributed to capacity charges or fixed charges in respect of that network level is:

> [p/kVA/day from network model assets] = 100*[standing charge factor]*[network level £/kW/year]*[user loss factor]/[network level loss factor]*(1 – [contribution proportion])/[days in year]/(1 + [diversity allowance])*[power factor in network model]
>
> [p/kVA/day from transmission exit or other expenditure] = 100*[standing charge factor]*[transmission exit or other expenditure £/kW/year]*[user loss factor]/[network level loss factor]/[days in year]/(1 + [diversity allowance])*[power factor in network model]

79. The power factor in network model parameter is set to 0.95.

80. The diversity allowance for the LV circuit level is defined as the amount by which the aggregate maximum demand load determined for that network level exceeds the estimated demand at the time of system simultaneous maximum load. The aggregate maximum demand is calculated by aggregating agreed import capacities for half hourly settled users and estimated capacities for non half hourly settled user groups.

81. For the tariffs listed below, the unit costs calculated by the formula above are allocated to the capacity charge. The exceeded capacity charge for half hourly settled demand

users, except unmetered users, is calculated using the same formula, but with the customer proportion set to zero.

- LV HH Metered
- LV Sub HH Metered
- HV HH Metered.

82. Otherwise, the unit costs calculated by the formula above are allocated to the fixed charge.

83. For the tariffs listed below, LV costs are allocated to the fixed charge by estimating the proportion of LV network capacity used by these categories of users, and dividing the corresponding proportion of LV costs by the number of domestic and non-domestic MPANs:

- Domestic Unrestricted
- Domestic Two Rate
- Small Non-Domestic Unrestricted
- Small Non-Domestic Two Rate
- LV Network Domestic
- LV Network Non-Domestic Non-CT.

84. For the tariffs listed below, the relevant unit costs in p/kVA/day are converted to a fixed charge by multiplying them by the estimated maximum load per user of the user category (obtained from the volume forecast and load factor data) divided by the power factor in the network model:

- LV Medium Non-Domestic
- LV Sub Medium Non-Domestic
- HV Medium Non-Domestic.

Costs associated with LV customer and HV customer levels

85. Other expenditure allocated to the LV customer and HV customer network levels are included in the fixed charge for each tariff where there is such a tariff component.

86. In the case of unmetered supplies, these charges are spread across all units.

Costs associated with reactive power flows

87. For each tariff and each network level, the contribution to reactive power unit charges is obtained as follows:

(a) Calculate what the contribution to a single unrestricted unit rate in p/kWh from each network level would be.

(b) Take the absolute value.

(c) Adjust for standing charge factors at the relevant network levels (for demand users only).

(d) Multiply by the assumed power factor in the network model.

(e) Multiply by the DNO Party's estimate of the average ratio of the reactive power flow (kVAr) to network load (kVA) at the relevant network level.

88. For the purpose of the calculation of reactive power unit charges, generation users are taken to make a full contribution to the reactive power flows in the network at their Entry Point and at each network level above their Entry Point.

Derivation of all-the-way tariffs before revenue matching and tariffs for customers connected to Licence Exempt Systems

88a. All-the-way tariffs before revenue matching are determined by summating across all voltages:

- the contribution to each unit rate at each voltage calculated in accordance with paragraph 77 and 86 as applicable;
- the contribution to fixed charges at each voltage calculated in accordance with paragraph 85;

- the contribution to capacity charges at each voltage calculated in accordance with paragraph 81; and
- the contribution to reactive power charges at each voltage calculated in accordance with paragraph 87.

88b. Tariffs for customers connected to Licence Exempt Systems are determined in accordance with paragraph 88a, save that lower voltage elements are excluded as follows:

- where the Licence Exempt System is connected to the LV network, the costs associated with the LV customer level are excluded;
- where the Licence Exempt System is connected at LV substation, the costs associated with the LV customer and LV network levels are excluded; and
- where the Licence Exempt System is connected at HV Network, the costs associated with the LV customer, LV network and LV substation levels are excluded.

Commented [EA4]: Calculations of PNO tariffs – all-the-way tariffs with some voltages excluded.

Commented [JL5R4]: Noted. We need to check definitions LV Network LV Customer, LV Substation etc.

88c. Capacity charge elements (p/kVA/day) for half-hourly site-specific settled customers connected to Licence Exempt Systems are allocated to the fixed charge (in p/day) by multiplying the capacity charge by the average kVA per customer for an equivalent all-the-way customer, determined from the DNO Party's volume forecast for the equivalent all-the-way half-hourly metered tariff at that voltage.

Commented [EA6]: Conversion of capacity charges to fixed charges – which I think is as agreed.

88d. Reactive power charge elements (p/kVArh) for half-hourly site-specific settled customers connected to Licence Exempt Systems are allocated to the fixed charge (in p/day) by multiplying the reactive power charge by the average kVArh per customer for an equivalent all-the-way customer, determined from the DNO Party's volume forecast for the equivalent all-the-way half-hourly metered tariff at that voltage, and dividing by the number of days in the charging year.

Commented [EA7]: Conversion of reactive power charges to fixed charges – which I think is as agreed.

Step 3: Match revenues

~~88.~~89. The DNO Party uses its volume forecasts to estimate the revenues that would be raised by applying the tariff components derived from step 2, excluding any revenues treated as excluded revenue under the price control conditions.

~~89.~~90. If any separate charging methodology is used alongside the CDCM, e.g. for EHV users, then the forecast revenues from these charges, excluding any revenues treated as excluded revenue under the price control conditions, are added to the total.

~~90.~~91. If the forecast of allowed revenue exceeds the estimate of relevant revenues, then the difference is a shortfall. If the estimate of relevant revenues exceeds the forecast of allowed revenue, then the difference is a surplus.

~~91.~~92. Revenue matching is achieved by applying a unit charge adder (p/kWh) to all-the-way charges calculated as follows: the revenue surplus or shortfall (in pence) to be recovered; divided by the total volume of all all-the-way and LDNO demand customers (in kWh). The unit charge adder is applied to all-the-way demand tariffs only.

~~92.~~93. The unit charges adder is positive if there is a shortfall and negative if there is a surplus.

~~93.~~94. If this procedure would result in negative value for any tariff component, then that tariff component is set to zero, and the unit charge adder figure is modified to the extent necessary to match forecast and target revenue.

~~94.~~95. ~~–~~Tariffs for generation and for customers connected to Licence Exempt Systems do not have any revenue matching element.

Commented [JL8]: This was agreed but we need a case for the consultation document.

Step 4: Price control disaggregation

~~95.~~96. Step 4 involves calculations based on price control and expenditure data which produce a series of discount percentages to be used to determine portfolio tariffs for LDNOs.

~~96.~~97. The discount percentages are determined in accordance with Schedule 29, which schedule is deemed to form part of this CDCM (as if it were set out herein).

~~97.~~98. For demand users, the discount percentages are applied to all tariff components in all-the-way tariffs in order to determine embedded network portfolio tariffs.

~~98.~~99. For generation users, the unit rate element (p/kWh) is not discounted, reflecting the modelling assumption that generation benefits are seen at the voltage level above the Exit Point, and therefore the embedded LDNO simply "passes on" the benefits seen at the DNO Party level. The fixed charge element (p/day) is discounted at 100 per cent, as this tariff component in the all-the-way tariff recovers costs associated with the allocation of other expenditure to service assets, which are not provided by the DNO Party.

~~99.~~100. Not used.

~~100.~~101. Not used.

~~101.~~102. Not used.

~~102.~~103. Not used.

~~103.~~104. Not used.

~~104.~~105. Not used.

~~105.~~106. Not used.

~~106.~~107. Not used.

~~107.~~108. Not used.

~~108.~~109. Not used.

~~109.~~110. Not used.

~~110.~~111. Not used.

~~111.~~112. Not used.

~~112.~~113. Not used.

~~113.~~114. Not used.

~~114.~~115. Not used.

~~115.~~116. Not used.

~~116.~~117. Not used.

~~117.~~118. Not used.

~~118.~~119. Not used.

~~119.~~120. Not used.

~~120.~~121. Not used.

~~121.~~122. Not used.

~~122.~~123. Not used.

~~123.~~124. Not used.

~~124.~~125. Not used.

Part 2 — Tariff structures and application

~~125.~~126. The development of the CDCM has involved the creation of a common tariff structure for all 14 DNO Parties and their Distribution Service Areas.

~~126.~~127. This part details the common tariff structure and associated tariff elements for Non-Half Hourly (NHH), Half-Hourly (HH) site-specific and HH aggregated metered supplies for demand and generation, for unmetered supplies, customers connected to Licence Exempt Systems and for charges to LDNOs.

Tariff structures for demand customers

NHH Metered Demand

~~127.~~128. Use of System Charges for NHH Metering Point Administration Numbers (MPANs) will be via the Supercustomer approach which uses data from the D0030 industry data flow and is based on Settlements Classes comprising:

(a) Line Loss Factor Class (LLFC);

(b) Profile Class (PC);

(c) Standard Settlement Configuration (SSC); and

(d) Time Pattern Regime (TPR)

~~128.~~129. The combination of LLFC/PC/SSC/TPR determines the associated profile and half-hourly data values.

~~129.~~130. NHH metered time bands will follow either, the appropriate SSC/TPR combinations with the allocation of the TPR to the unit rate set by the DNO Party, or the time bands set by DNO Parties where that DNO Party already utilises a form of 'de-linking'.

~~130.~~131. Charges will be applied on a fixed charge and unit rate basis. There will be no capacity, exceeded capacity, maximum demand or reactive charges for NHH metered MPANs.

~~131.~~132. Structure of NHH demand charges:

(a) Fixed charge will be p/MPAN/day.

(b) Unit charges will be p/kWh.

(c) Unmetered supplies will be charged on a p/kWh basis only.

Changes from NHH to HH Settlement for Metered Demand

132A Prior to Measurement Classes F and G being available under the BSC, where the Supplier transfers customers from NHH Settlement to HH Settlement, Measurement Class C (100kW or more) and Measurement Class E (less than 100kW) will apply.

132B Once Measurement Classes F and G are available under the BSC, where the Supplier transfers customers from NHH Settlement to HH Settlement the following Measurement Classes will apply:

- Domestic users connected at LV with non-CT metering installed will transfer from Measurement Class A to Measurement Class F.

- Domestic users connected to LV with CT metering can (at supplier option in discussion with user) move to Measurement Class C (must be more than 100kW), Measurement Class E (must be 100kW or less) or Measurement Class F (must be 100kW or less).

- Non-Domestic users connected at LV with non-CT metering installed will transfer from Measurement Class A to Measurement Class G.

- Non-Domestic users connected at LV with CT metering installed will transfer from Measurement Class A to Measurement Class C (more than 100kW) or Measurement Class E (100kW or less).

HH Site-Specific Metered Demand

~~132.~~133. Use of System Charges for HH settled site-specific demand customers will use data from the D0275 or D0036 industry data flows based on half hourly metered data provided by MPAN.

~~133.~~134. Charges will consist of a fixed, unit, capacity and reactive power charge.

~~134.~~135. As described in Paragraph 40, there will be three unit rate time bands on a time of day basis for all half hourly settled customers with the exception of the half hourly unmetered supplies tariff, to reflect the requirements of the cost drivers of their individual networks. These three time bands will be called ‘red’, ‘amber’ and ‘green’ to represent three differing cost signals. As described in Paragraph 40, there will be three unit rate time bands for the half hourly unmetered supplies tariff, to reflect the requirements of the cost drivers of their individual networks. The three time bands will be called ‘black’, ‘yellow’ and ‘green’ to represent three differing cost signals.

135A Prior to Measurement Classes F and G being available under the BSC, those users in Measurement Class C or E will be HH settled on a site-specific basis, and assigned to the appropriate tariff based on the Measurement Class, type of metering equipment installed and the voltage of connection as specified in the table below:

Tariff	Voltage of Connection	Metering	Measurement Class

LV HH Metered	LV	Whole current/Current Transformer	C / E
LV Sub HH Metered	LV Sub	Whole current/Current Transformer	C / E
HV HH Metered	HV	Current Transformer	C / E

135B. This paragraph only applies once Measurement Classes F and G are available under the BSC. Where this paragraph applies, those users who remain in Measurement Class C or E will be HH settled on a site specific basis, while those users in Measurement Class F or G will be settled on an aggregate basis. HH settled customers will be assigned to the appropriate tariff based on the Measurement Class, type of metering equipment installed and the voltage of connection as specified in the table below:

Tariff	**Voltage of Connection**	**Metering**	**Measurement Class**
LV Network Domestic	LV	Whole Current or Current Transformer	F
LV Network Non-Domestic Non-CT	LV	Whole Current	G
LV HH Metered	LV	Current Transformer	C / E
LV Sub HH Metered	LV Sub	Current Transformer	C / E
HV HH Metered	HV	Current Transformer	C / E

~~135.~~136. Structure of the HH demand charges:

(a) Fixed charge p/MPAN/day;

(b) Unit rate charge p/kWh;

(c) Unmetered supplies will be charged on a p/kWh basis only;

(d) Capacity charge p/kVA/day (with the exception of tariffs for customers connected to Licence Exempt Systems);

(e) Exceeded capacity charge p/kVA/day (with the exception of tariffs for customers connected to Licence Exempt Systems); and

(f) Reactive power charge p/kVArh (with the exception of tariffs for customers connected to Licence Exempt Systems).

~~136.~~137. Generally the p/MPAN/day charge relates to one MPAN. However, where a site is a group of MPANs as identified in the connection agreement, billing systems should be able to group the MPANs where appropriate for charging purposes.

~~137.~~138. Unit charges will be allocated by settlements HH data and DNO Party specific network time bands.

~~138.~~139. There will be no charges applied to correctly de-energised HH MPANs/sites as determined by the de-energisation status in MPAS Registration System.

~~139.~~140. Where a site is incorrectly de-energised, i.e. when actual metering advances are received the DNO Parties should contact suppliers to ensure the status is corrected. If a site is found to be energised charges will be back dated to the date of energisation.

140A. Use of System Charges for HH aggregated metered demand MPANs (as determined under paragraph 135B above) will be via the Supercustomer approach which uses data from the D0030 industry data flow and is based on Settlement Classes comprising:

a) Line Loss Factor Class (LLFC);

b) Profile Class (PC);

c) Standard Settlement Configuration (SSC); and

d) Time Pattern Regime (TPR)

140B. The combination of LLFC/PC/SSC/TPR determines the associated profile and half hourly data values. These will be determined by the DNO Party and provided to the Supplier Volume Allocation Agent. The PC for HH aggregated metered demand MPANs will always be zero.

140C. DNO specific network time bands will be applied to the appropriate SSC/TPR combinations stated in paragraph 140B.

140D. Charges will be applied on a fixed charge and unit rate basis, the latter allocated to DNO specific network timebands. There will be no capacity, exceeded capacity or reactive power charges for HH aggregated metered demand MPANs.

140E. Structure of HH aggregated metered demand charges shall be as follows:

a) Fixed charge will be p/MPAN/day

b) Unit charges will be p/kWh.

Demand Tariff Structures

~~140.~~141. Table 4 below shows the structure for NHH metered demand tariffs, and Table 5 below shows the structure for HH metered demand tariffs (both site-specific and aggregated).

Table 4: Non-half-hourly metered demand tariffs

Point of Connection	Tariff Name	Profile Class	Unit rate 1* p/kWh	Unit rate 2* p/kWh	Fixed charge p/MPAN/day
LV	Domestic Unrestricted	1	✓		✓
LV	Domestic Two Rate	2	✓	✓	✓
LV	Domestic Off-Peak (related MPAN)	2	✓		
LV	Small Non-Domestic Unrestricted	3	✓		✓
LV	Small Non-Domestic Two Rate	4	✓	✓	✓
LV	Small Non-Domestic Off-Peak (related MPAN)	4	✓		
LV	LV Medium Non-Domestic	5 to 8	✓	✓	✓
LV	NHH UMS (Category A)	8	✓		
LV	NHH UMS (Category B)	1	✓		
LV	NHH UMS (Category C)	1	✓		
LV	NHH UMS (Category D)	1	✓		
LVS	LV Sub Medium Non-Domestic	5 to 8	✓	✓	✓
HV	HV Medium Non-Domestic	5 to 8	✓	✓	✓

* Unit rates 1 and 2 for NHH customers are either unrestricted or based upon the TPR or the DNO specific combinations.

Table 5: Half-hourly metered demand tariffs							
Tariff	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN /day	Capacity charge p/kVA/ day	Exceeded Capacity charge p/kVA/day	Reactive power charge p/kVArh
LV Network Domestic	Red	Amber	Green	✓			
LV Network Non-Domestic Non-CT	Red	Amber	Green	✓			
LV HH Metered	Red	Amber	Green	✓	✓	✓	✓
LV Sub HH Metered	Red	Amber	Green	✓	✓	✓	✓
HV HH Metered	Red	Amber	Green	✓	✓	✓	✓
LV UMS (Pseudo HH Metered)	Black	Yellow	Green				

Note 1: The Domestic and Non-Domestic off-peak (related MPAN) tariffs are supplementary to a standard published tariff and therefore only available under these conditions.

Note 2: Where DNO Parties use a default tariff for invalid settlement combinations these will be charged at the Domestic Unrestricted rates.

Note 3: LV Sub applies to customers connected to the DNO Party's network at a voltage of less than 1 kV at a substation with a primary voltage (the highest operating voltage present at the substation) of at least 1 kV and less than 22 kV, where the current transformer (CT) used for the customer's settlement metering is located at the substation. For these purposes, 'at the substation' means:

a) an HV/LV substation with the metering CT in the same chamber as the substation transformer; or

b) an HV/LV substation with the metering CT in a chamber immediately adjacent to the substation transformer chamber.

Note 4: not used.

Note 5: Where a customer or its supplier requests a DNO Party to confirm if a connection may be eligible for an LV Sub tariff, the DNO Party will investigate and reach a decision, taking account of any supporting information provided by the customer or supplier and any additional information that is available to it. Administration charges (to cover reasonable costs) may apply if a technical assessment or site visit is required, but shall not be applied where the DNO Party agrees to the change of tariff request. In all circumstances where a DNO Party decides or agrees that a customer should be moved to an LV Sub tariff, the new tariff charges will be applied in the next calendar month following the DNO Party's decision or agreement. Where a customer is already registered on an LV Sub tariff they will remain so.

Note 6: HV Medium Non-Domestic - This tariff will be closed to new customers and all new HV connections will be required to be half-hourly metered.

Note 7: Fixed charges are generally levied on a pence per MPAN basis. However, there are some instances in the half-hourly market where more than one MPAN exists on a customer's connection and only one fixed charge is appropriate. Where a group of MPANs is classed as a site as identified in the connection agreement, billing systems should be able to group the MPANs, where appropriate, for charging purposes.

Tariff structures for generation

NHH and Aggregated HH Metered Generation

~~141.~~142. Use of System Charges for NHH Low Voltage (LV and LVS) generation tariffs and aggregated HH LV generation will be billed via Supercustomer. The billing systems will be required to apply fixed charges plus negative unit charges with the process being managed through the DNO Party's invoicing of the supplier.

~~142.~~143. Structure of NHH and aggregated HH generation charges:

(a) Fixed charge will be p/MPAN/day; and

(b) Unit rate charge p/kWh.

HH Metered Generation (other than Aggregated)

~~143.~~144. Use of System Charges for HH Low Voltage (LV) and High Voltage (HV) generation tariffs (excluding aggregated HH LV generation) will be via the HH billing systems. The billing systems will be required to apply fixed charges plus reactive power unit charges, negative unit charges and manage the process through the DNO Party's invoicing of the supplier

~~144.~~145. Structure of HH generation charges:

(a) Fixed charge will be p/MPAN/day;

(b) Unit rate charge p/kWh; and

(c) Reactive power charge p/kVArh.

~~145.~~146. The following tables and notes show the structure for generation tariffs.

Table 6: Non-half-hourly metered generation tariffs				
Point of Connection	Tariff Name	Profile Class	Unit rate 1 p/kWh	Fixed charge p/MPAN/day
LV	LV Generation NHH or Aggregate HH*	8 or 0	✓	✓
LVS	LV Sub Generation NHH	8	✓	✓

* This tariff can be settled NHH or aggregated HH

Table 7: Half-hourly metered generation tariffs					
Tariff	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN/day	Reactive power charge p/kVArh
LV Generation Intermittent	✓			✓	✓
LV Sub Generation Intermittent	✓			✓	✓
HV Generation Intermittent	✓			✓	✓
LV Generation Intermittent no RP charge	✓			✓	
LV Sub Generation Intermittent no RP charge	✓			✓	
HV Generation Intermittent no RP charge	✓			✓	
LV Generation Non-Intermittent	Red	Amber	Green	✓	✓
LV Sub Generation Non-Intermittent	Red	Amber	Green	✓	✓
HV Generation Non-Intermittent	Red	Amber	Green	✓	✓
LV Generation Non-Intermittent no RP charge	Red	Amber	Green	✓	
LV Sub Generation Non-Intermittent no RP charge	Red	Amber	Green	✓	
HV Generation Non-Intermittent no RP charge	Red	Amber	Green	✓	

Note 1: A single-rate tariff is applied to NHH settled generation, as there is no readily available and accurate information about the time at which units are delivered.

Note 2: Intermittent generation is defined as a generation plant where the energy source of the prime mover cannot be made available on demand, in accordance to the definitions in Engineering Recommendation P2/6. These include wind, tidal, wave, photovoltaic and small hydro. The operator has little control over operating times therefore, a single-rate tariff (based on a uniform probability of operations across the year) will be applied to intermittent generation.

Note 3: Non-intermittent generation is defined as a generation plant where the energy source of the prime mover can be made available on demand, in accordance to the definitions in Engineering Recommendation P2/6. The generator can choose when to operate, and bring more benefits to the network if it runs at times of high load. These include combined cycle gas turbine (CCGT), gas generators, landfill, sewage, biomass, biogas, energy crop, waste incineration and combined heat and power (CHP). A three-rate tariff will be applied to generation credits for half-hourly settled non-intermittent generation.

Note 4: LV Sub Generation applies to customers connected to the DNO Party's network at a voltage of less than 1 kV at a substation with a primary voltage (the highest operating voltage present at the substation) of at least 1 kV and less than 22 kV, where the current transformer used for the customer's settlement metering is located at the substation.

Note 5: not used.

Note 6: Note 4 above for LV generation substation tariffs will be applied for new customers from 1 April 2010.

Note 7: Where a DNO Party has requested (and still requires) a generator to operate with a power factor of less than 0.95, excess reactive power charges will not apply (these instances are identified in the table as 'no RP charge').

Tariff structures for Licence Exempt Systems using Difference Metering

146A The tariffs charged in respect of Licence Exempt Systems using Difference Metering shall be charged to the Supplier at the DNO Party's boundary based on the units imported or exported at the boundary between the network and the Licence Exempt System. No charges will be applied by the DNO Party to the boundary settlements data received by the DNO Party, or to the settlements data received in respect of ~~the~~any settlement meters within the Licence Exempt System.

146B The tariffs charged in respect of Licensed Exempt Systems using fully settled or shared metering shall be charged to each Supplier within the Licence Exempt System based on the settlements data received in respect of the settlements meter at each Metering Point within the Licence Exempt System, and is dependent on the voltage of the Point of Connection of the Licence Exempt System to the ~~licensed~~ D~~d~~istribution S~~s~~ystem, being either LV network (see Table 146B.1), LV substation (see Table 146B.2) or HV (see Table 146B.~~2~~3). ~~:~~

Table 146B.1: Licence Exempt System Tariffs - LV connection*

Tariff Name	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN /day	Capacity charge p/kVA/ day	Exceeded Capacity charge p/kVA/day	Reactive power charge p/kVArh
LV Domestic Aggregated	Red	Amber	Green	✓			
Domestic Aggregated (Related MPAN)	Red	Amber	Green				
Non-Domestic Aggregated	Red	Amber	Green	✓			
Non-Domestic Aggregated (Related MPAN)	Red	Amber	Green				
LV Site Specific	Red	Amber	Green	✓			
Unmetered Supplies**	Black	Yellow	Green				

Commented [JL9]: Still need to add in the definitions to the glossary

Commented [JL10]: this is true for fully settled sites but not for shared sites. With the definitions used we may be able to shorten this

Commented [EA11]: The draft tariffs I created were differentiated between those where the PNO provided only the LV services, provided the LV mains and LV services, or connected at HV

Commented [JL12]: Used this notation which was approved by the Panel for all table numbers to be amended and follow the para number.

LV Generation Aggregated	Red	Amber	Green				
LV Generation Site Specific	Red	Amber	Green				

* Where the boundary between the Licence Exempt System and the Distribution System is at LV but not at an HV/LV substation.

Table 146B.2 Licence~~d~~ Exempt System Tariffs - LV Substation connection*

Tariff Name	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN /day	Capacity charge p/kVA/ day	Exceeded Capacity charge p/kVA/day	Reactive power charge p/kVArh
LV Domestic Aggregated	Red	Amber	Green	✓			
Domestic Aggregated (Related MPAN)	Red	Amber	Green				
Non-Domestic Aggregated	Red	Amber	Green	✓			
Non-Domestic Aggregated (Related MPAN)	Red	Amber	Green				
LV Site Specific	Red	Amber	Green	✓			
Unmetered Supplies**	Black	Yellow	Green				

LV Generation Aggregated	Red	Amber	Green				
LV Generation Site Specific	Red	Amber	Green				

* Where the boundary between the Licence Exempt System and the Distribution System is at an HV/LV substation.

Table 146B.~~2~~3: Licence Exempt System Tariffs - HV connection*

Tariff Name	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN/day	Capacity charge p/kVA/day	Exceeded Capacity charge p/kVA/day	Reactive power charge p/kVArh
LV Domestic Aggregated	Red	Amber	Green	✓			
LV Domestic Aggregated (Related MPAN)	Red	Amber	Green				
LV Non-Domestic Aggregated	Red	Amber	Green	✓			
LV Non-Domestic Aggregated (Related MPAN)	Red	Amber	Green				
LV Site Specific	Red	Amber	Green	✓			
Unmetered Supplies	Black	Yellow	Green				
LV Sub Site Specific	Red	Amber	Green	✓			

HV Site Specific	Red	Amber	Green	✓				
LV Generation Aggregated	Red	Amber	Green	✓				
LV Sub Generation Aggregated	Red	Amber	Green	✓				
LV Generation Site Specific	Red	Amber	Green	✓				
LV Sub Generation Site Specific	Red	Amber	Green	✓				
HV Generation Site Specific	Red	Amber	Green	✓				

* Where the boundary between the Licence Exempt System and the Distribution System is at HV.

Tariff structures for LDNOs

~~146.~~147. The tariff structure for LDNOs will mirror the structure of the all-the-way-tariff, and is dependent on the voltage of the Point of Connection being either LV (see Table 8) or HV (see Table 9); except for the LDNO UMS tariffs (marked with ** in Tables 8 and 9 below), which are charged by reference to the voltage of the Points of Connection that provide the majority of the energised domestic connections for the LDNO in the GSP Group (or, where there is no such majority, on such other reasonable basis as the DNO Party determines). In all cases, the same tariff elements will apply.

Table 8: LDNO LV connection*								
Profile Class	Tariff Name	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN /day	Capacity charge p/kVA /day	Exceeded Capacity charge p/kVA /day	Reactive power charge p/kVArh

1	Domestic Unrestricted	✓			✓			
2	Domestic Two Rate	✓	✓		✓			
2	Domestic Off-Peak (related MPAN)	✓						
3	Small Non-Domestic Unrestricted	✓			✓			
4	Small Non-Domestic Two Rate	✓	✓		✓			
4	Small Non-Domestic Off-Peak (related MPAN)	✓						
5 to 8	LV Medium Non-Domestic	✓	✓		✓			
8	NHH UMS (Category A)	✓						
1	NHH UMS (Category B)	✓						
1	NHH UMS (Category C)	✓						
1	NHH UMS (Category D)	✓						
0	LV Network Domestic	Red	Amber	Green	✓			
0	LV Network Non-Domestic Non-CT	Red	Amber	Green	✓			
0	LV HH Metered	Red	Amber	Green	✓	✓	✓	✓
0	LV UMS (Pseudo HH Metered)	Black	Yellow	Green				
0 or 8	LV Generation NHH or Aggregate HH	✓			✓			
0	LV Generation Intermittent	✓			✓			✓
0	LV Generation Non-Intermittent	Red	Amber	Green	✓			✓

* Where the boundary between the LDNO and DNO network is at LV

Table 9: LDNO HV connection*

Profile Class	Tariff Name	Unit rate 1 p/kWh	Unit rate 2 p/kWh	Unit rate 3 p/kWh	Fixed charge p/MPAN /day	Capacity charge p/kVA /day	Exceeded Capacity charge p/kVA /day	Reactive power charge p/kVArh
1	Domestic Unrestricted	✓			✓			
2	Domestic Two Rate	✓	✓		✓			

Table 9: LDNO HV connection*								
2	Domestic Off-Peak (related MPAN)	✓						
3	Small Non-Domestic Unrestricted	✓			✓			
4	Small Non-Domestic Two Rate	✓	✓		✓			
4	Small Non-Domestic Off-Peak (related MPAN)	✓						
5 to 8	LV Medium Non-Domestic	✓	✓		✓			
8	NHH UMS (Category A)	✓						
1	NHH UMS (Category B)	✓						
1	NHH UMS (Category C)	✓						
1	NHH UMS (Category D)	✓						
0	LV Network Domestic	Red	Amber	Green	✓			
0	LV Network Non-Domestic Non-CT	Red	Amber	Green	✓			
0	LV HH Metered	Red	Amber	Green	✓	✓	✓	✓
0	LV UMS (Pseudo HH Metered)	Black	Yellow	Green				
0	LV Sub HH Metered	Red	Amber	Green	✓	✓	✓	✓
0	HV HH Metered	Red	Amber	Green	✓	✓	✓	✓
0 or 8	LV Generation NHH or Aggregate HH	✓			✓			
0	LV Generation Intermittent	✓			✓			✓
0	LV Generation Non-Intermittent	Red	Amber	Green	✓			✓
0	LV Sub Generation Intermittent	✓			✓			✓
0	LV Sub Generation Non-Intermittent	Red	Amber	Green	✓			✓
0	HV Generation Intermittent	✓			✓			✓
0	HV Generation Non-Intermittent	Red	Amber	Green	✓			✓

Capacity charges

Maximum Import Capacity

~~147.~~148. The Maximum Import Capacity (MIC) will be charged on a site basis (p/kVA/day).

~~148.~~149. The level of MIC will be agreed at the time of connection and when an increase has been approved. Following such an agreement (be it at the time of connection or an increase) no reduction in MIC will be allowed for a period of one year (subject to Part 4 below).

~~149.~~150. Subject to Part 4 below, reductions to the MIC may only be permitted once in a 12 month period and no retrospective changes will be allowed. Where MIC is reduced the new lower level will be agreed with reference to the level of the customers' maximum demand. It should be noted that where a new lower level is agreed the original capacity may not be available in the future without the need for network reinforcement and associated cost.

~~150.~~151. For LDNO connections, if capacity ramping has been agreed with the DNO Party, in accordance with the DNO Party's connection charging methodology, the phasing profile will apply instead of the above rules. Where an LDNO has agreed a phasing of capacity this will be captured in the Bilateral Connection Agreement with the DNO Party.

Standby Capacity for Additional Security on Site

~~151.~~152. Where standby capacity charges are applied, the charge will be set at the same rate as that applied to normal MIC.

Exceeded Capacity

~~152.~~153. Where a customer takes additional capacity over and above the MIC without authorisation, the excess will be classed as exceeded capacity. The exceeded portion of the capacity will be charged at the exceeded capacity rate (p/kVA/day). The exceeded capacity will be charged for the duration of the month in which the breach occurs and derived as follows:

Exceeded capacity (kVA) = max (0, Chargeable capacity – MIC)

Where:

Chargeable capacity = actual capacity utilised as set out below

MIC = Maximum Import Capacity

Minimum Capacity Levels

~~153.~~154. There is no minimum capacity threshold.

Capacity Value Calculations – Import

~~154.~~155. The actual capacity utilised will be calculated by the following formula:

$$\text{Import Demand} = 2 \times \sqrt{\text{AI}^2 + \max(RI, RE)^2}$$

Where:

AI = Import consumption in kWhRI = Reactive import in kVArh

RE = Reactive export in kVArh

Import Demand = kVA

~~155.~~156. This calculation is completed for every half hour and the maximum value from the billing period is captured.

~~156.~~157. Not used.

~~157.~~158. Only kVArh Import and kVArh Export values occurring at times of kWh Import are used.

Capacity Value Calculations – Export

~~158.~~159. The actual capacity utilised will be calculated by the following formula:

$$\text{Export Demand} = 2 \times \sqrt{\text{AE}^2 + \max(RI, RE)^2}$$

Where:

AE = Export production in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

Export Demand = kVA

~~159.~~160. This calculation is completed for every half hour and the maximum value from the billing period is captured.

~~160.~~161. The export demand value is calculated to record the highest export value and used for information only.

~~161.~~162. Only kVArh Import and kVArh Export values occurring at times of kWh Export are used.

Reactive power charges

~~162.~~163. Reactive power charges will be applied based on chargeable reactive power. The charge will be p/kVArh for units in excess of a set amount.

~~163.~~164. The chargeable reactive power units will be calculated by the following formulae.

Chargeable Reactive Power Unit Calculations - Import

$$\text{Chargeable kVArh} = \max\left(\max(\text{RI}, \text{RE}) - \left(\sqrt{\left(\frac{1}{0.95^2} - 1\right)} \times AI\right), 0\right)$$

Where:

AI = Import consumption in kWh

RI = Reactive Import in kVArh

RE = Reactive export in kVArh

~~164.~~165. The 0.95 constant refers to the reactive charging threshold and the design power factor of the network model within the CDCM.

~~165.~~166. This calculation is completed for every half hour and the values summated over the billing period.

~~166.~~167. Only kVArh Import and kVArh Export values occurring at kWh Import are used.

~~167.~~168. The square root calculation will be to two decimal places.

Chargeable Reactive Power Unit Calculations - Export

$$\text{Chargeable kVArh} = \max\left(\max(\text{RI},\text{RE}) - \left(\sqrt{\left(\frac{1}{0.95^2} - 1\right)} \times AE\right), 0\right)$$

Where:

AE = Export production in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

~~168.~~169. The 0.95 constant refers to the reactive charging threshold and the design power factor of the network model within the CDCM.

~~169.~~170. This calculation is completed for every half hour and the values summated over the billing period.

~~170.~~171. Only kVArh Import and kVArh Export values occurring at kWh Export are used.

~~171.~~172. The square root calculation will be to two decimal places.

Charging decimal places

~~172.~~173. DNO Parties will set unit charges (kWh) and reactive power charges (kVArh) to three decimal places. The rates for fixed charges and capacity charges and exceeded capacity charges will be set to two decimal places.

Part 3 — Network Unavailability Rebate Payments

~~173.~~174. A compensation payment may be payable to customers for network outages under two schemes.

~~174.~~175. The majority of customers are compensated under the Guaranteed Standards arrangements set out in The Electricity (Standards of Performance) Regulations 2015.

~~175.~~176. Customers who are off supply for greater than defined periods of time are entitled to a payment. This scheme applies to all demand customers and to all generators not included in the scheme described below.

~~176.~~177. For customers with generation connected at more than 1,000 volts and who have agreed a standard connection the following scheme will apply. This scheme is known as Distributed Generation Network Unavailability Rebate and payments will be calculated for each generator on the following basis:

Payment = A*B*(C-D)

Where:

A = the network unavailability price of £2 per MW per hour.

B = incentivised generator capacity; the highest active electrical power that can be generated (or the relevant incremental change of this amount in cases of the expansion of existing generation plant) by the generator for the year, according to the connection and/or use of system agreement(s).

C = network interruption duration; the total duration of all occurrences (in minutes) on the network each of which involves a physical break in the circuit between itself and the rest of the system or due to any other open circuit condition, which prevents the generator from exporting power. It excludes:

- 50 per cent of the total duration of cases where the DNO Party takes pre-arranged outages of its equipment for which the statutory notification has been issued to the generator;

- the cases where the generator has specific exemption agreements with the DNO Party in the connection and/or use of system agreement(s); and

- the cases which are part of exempted events in the quality of service incentive or the Guaranteed Standard Statutory Instrument (such exemptions include interruptions of less than three minutes duration and industrial action).

D = the baseline network interruption duration for the relevant year which either has a default value of zero or some other value agreed between the customer and the DNO Party and recorded within either; the connection offer, connection agreement and/or use of system agreement(s).

~~177.~~178. Distributed Generation Network Unavailability Rebate scheme payments will be calculated by the DNO Party on an annual basis (1st April - 31st March) and payments made shortly after the end of each year. This payment is automatic and does not need to be claimed by the generation customer. The de minimis level of rebate is £5 (and below that amount no payment will be made).

Part 4 – Transitional Protection for Customers affected by BSC Modification P272

~~178.~~179. This Part 4 sets out the transitional protection for Customers who may be affected by BSC Modification P272, being demand Customers in Profile Class (PC) 5-8 which are required to become half-hourly settled (where capable metering has been installed).

~~179.~~180. This Part 4 forms part of the CDCM, but also applies to IDNO Parties and to DNO Parties acting outside of their distribution services area.

~~180.~~181. Subject to paragraph 183 below, where:

(a) a Customer takes a supply of electricity at a Premises where the electricity conveyed to the Premises is recorded through a CT meter; and

(b) the Metering Point for such Premises has, on or before 31 March 2017, been migrated to Measurement Class C or E, as a result of BSC Modification P272,

then, for a period of twelve months immediately following the date of the migration to Measurement Class C or E, a lower Maximum Import Capacity (**MIC**) may be agreed between the Customer and the DNO/IDNO Party. In such circumstances, the revised MIC will be applied retrospectively from the date of the migration to Measurement Class C or E.

~~181.~~182. In respect of any change in MIC under paragraph 181 above:

(a) such revised MIC will be agreed with reference to the level of the Customer's maximum demand;

(b) no further changes in MIC shall be permitted under paragraph 181 above; and

(c) paragraphs 149 and 150 of the CDCM (or any equivalent or similar statements in the applicable charging methodology if the CDCM does not apply) shall apply to the revised MIC from the date the retrospective change is agreed.

~~182.~~183. Paragraph 181 above shall not apply:

(a) where a Connection Agreement has been entered into for the Premises within the twelve months immediately prior to the date of the change in Measurement Class, in which case the terms of that Connection Agreement shall stand; or

(b) where the Customer was neither the owner nor the occupier of the Premises at the time of the migration to Measurement Class C or E.

~~183.~~184. In this Part 4, the following definitions shall apply:

BSC Modification P272	means the modification to the BSC referred to as modification 'P272, Mandatory Half Hourly Settlement for Profile Classes 5-8', which was approved by the Authority on 29 October 2014.
Measurement Class	has the meaning given to that expression in the BSC.
Profile Class	has the meaning given to that expression in the BSC.

Glossary of Terms used in this Schedule 16

In this Schedule 16, except where the context otherwise requires, the expressions in the left-hand column below shall have the meaning given to them in the right-hand column below:

Term	***Meaning***
allowed revenue	the DNO Party's "Combined Allowed Distribution Network Revenue" (as defined in the DNO Party's price control conditions).

Term	*Meaning*
all-the-way tariff	a tariff applicable to an end user rather than an LDNO.
boundary tariff	a tariff for use of the DNO Party’s network by an LDNO where charges are based on boundary flows.
CDCM	the Common Distribution Charging Methodology.
charging year	the 12-month period ending on a 31st March for which charges and credits are being calculated.
coincidence factor	for a user category, aggregate load at the time of the DNO Party’s system simultaneous maximum load divided by maximum aggregate load.
Common Distribution Charging Methodology	the methodology of that name with which the DNO Party is obliged to comply under its Distribution Licence.
contribution proportion	the proportion of asset annuities which are deemed covered by customer contributions. This is defined for each combination of a tariff and a network level.
customer contribution	capital charges payable by customers under the DNO Party’s connection charging policy.
CT	Current Transformer, indicating metering which uses current transformers to induce a reference current which is then passes through the meter (as compared to non-CT or whole current metering, where the full electrical current passes through the meter).
distribution time bands	the time bands described in paragraphs 40, 41 and 135.

Term	*Meaning*
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, as per paragraph 27.
DRM	distribution reinforcement model. This may refer either to a 500 MW network model or to a cost allocation method based on such a model.
EDCM	means the EHV distribution charging methodology as described in Schedule 17 or Schedule 18 (as applicable to each DNO Party).
EHV	EHV refers to nominal voltages of at least 22kV and less than 132kV; network elements with a nominal voltage of 132kV are excluded from EHV for the purpose of this Schedule 16.
embedded network	an electricity distribution system operated by an LDNO and embedded within the DNO Party's network.
end user	is a user, but excluding LDNOs.
Engineering Recommendation	one of the engineering recommendations referred to in the Distribution Code.
excluded revenue	revenue from "Excluded Services" (as defined in the price control conditions).
Forecast Business Plan Questionnaire or FBPQ	the questionnaire that the DNO Party is required to submit under the Regulatory Instructions and Guidance issued by the Authority under the DNO Party's Distribution Licence.

Term	***Meaning***
fully settled	where every customer on a Licence Exempt System is to have or has a Supplier, its own MPAN and metering equipment and there is no metering equipment at the boundary between the Distribution System and the Licence Exempt System. The BSC refers to these circumstances as an ‘Associated Distribution System’.
GSP	grid supply point: where the network is connected to a transmission network.
HV	nominal voltages of at least 1kV and less than 22kV.
kV	Kilovolt (1,000 Volts): a unit of voltage.
kVAr	Kilo Volt Ampere reactive: a unit of reactive power flow.
kVArh	Kilo Volt Ampere reactive hour: a unit of total reactive power flow over a period of time.
kW	Kilowatt (1,000 Watts): a unit of power flow.
kWh	Kilowatt hour: a unit of energy.
LDNO	a licensed distribution network operator, meaning an IDNO Party or DNO Party operating an electricity distribution system outside of its Distribution Services Area.
load factor	for a user category, average load divided by maximum aggregate load.
LV	nominal voltages of less than 1kV.

Term	*Meaning*
LV Mains	LV distributing mains where: (a) the upper boundary is at the secondary side (LV) of a distributor transformer; and (b) the lower boundary is the point of connection associated with the LV service.
LV Services	the service line from the LV main to the DNO's protection device situated upon the customer's premises, including the joint and associated components connecting the service line to the distributing main.
Measurement Class	has the meaning given to that expression in the BSC.
modern equivalent asset and modern equivalent asset value	is a reference to the cost of replacing an asset at the time of the calculation.
MPAN	the unique number identifying a particular Metering Point or Metering System.
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.
network	the DNO Party's Distribution System within the DNO Party's Distribution Services Area.

Term	*Meaning*
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. Additional network levels are used for transmission exit and for LV and HV customer assets.
network model	a costed design for a 500 MW extension to the DNO Party's network, as described in paragraph 16.
peaking probability	is the peaking probability described in paragraph 49.
power factor	the ratio of energy transported (kW) to network capacity used (kVA).
portfolio tariff	a tariff for use of the DNO Party's network by an LDNO where charges are based on flows out of/into the LDNO's electricity distribution system from its end users or further nested networks.
price control conditions	the charge restriction conditions contained as special conditions within the DNO Party's Distribution Licence.
profile class	has the meaning given to that expression in the Balancing and Settlement Code.
regulatory asset value	is the DNO Party's regulatory asset value as described in the Regulatory Instructions and Guidance issued by the Authority under the DNO Party's Distribution Licence.
related MPAN	has the meaning given to the expression "Related Metering Points" in the Master Registration Agreement.
Revenue not to share	means the amount described as such in paragraph 111.
RRP	regulatory reporting pack, a dataset produced each year by each DNO Party for the Authority.

Term	*Meaning*
service model	a costed design for the typical dedicated assets of a category of network users.
Shared metering	where meter readings recorded by Settlement metering equipment at the boundary between the Distribution System and the Licence Exempt System are apportioned between Suppliers based on readings from non-Settlement meters on a Licence Exempt System.
standing charge	any fixed or capacity charge that does not depend on actual use of the network.
Supercustomer	in relation to billing, is billing by Settlement Class.
system simultaneous maximum load	the maximum load for the GSP Group as a whole.
time pattern regime or TPR	means a code that is used to identify the switching times of a meter register.
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.
user	refers to customers (whether demand customers or generators) and (where relevant) LDNOs.

SCHEDULE 17 – EHV CHARGING METHODOLOGY (FCP MODEL)

1. INTRODUCTION

This Schedule 17, version 10.0, is to be used for the calculation of Use of System Charges which will become effective from, 01 April 2018 and remain effective until superseded by a revised version.

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

1.2 This Schedule 17 sets out the methods, principles, and assumptions underpinning the EDCM for the calculation of Use of System Charges by the following DNO Parties:

Scottish Hydro Electric Power Distribution plc;

Southern Electric Power Distribution plc;

SP Distribution Limited;

SP Manweb plc;

Western Power Distribution (East Midlands) plc; and

Western Power Distribution (West Midlands) plc.

1.3 In order to comply with this methodology statement when setting distribution Use of System Charges the DNO Parties referred to above will populate the EDCM model version F204 when issued by the Panel in accordance with Clause 14.5.3.

Main Steps

1.4 The EDCM involves four main steps.

1.5 Step 1 is the application of load flow techniques and the LRIC or FCP methodologies to determine an EDCM tariff element, known as Charge 1, which represents costs associated with demand-led reinforcement, estimated by reference to power flows in the maximum demand scenario.

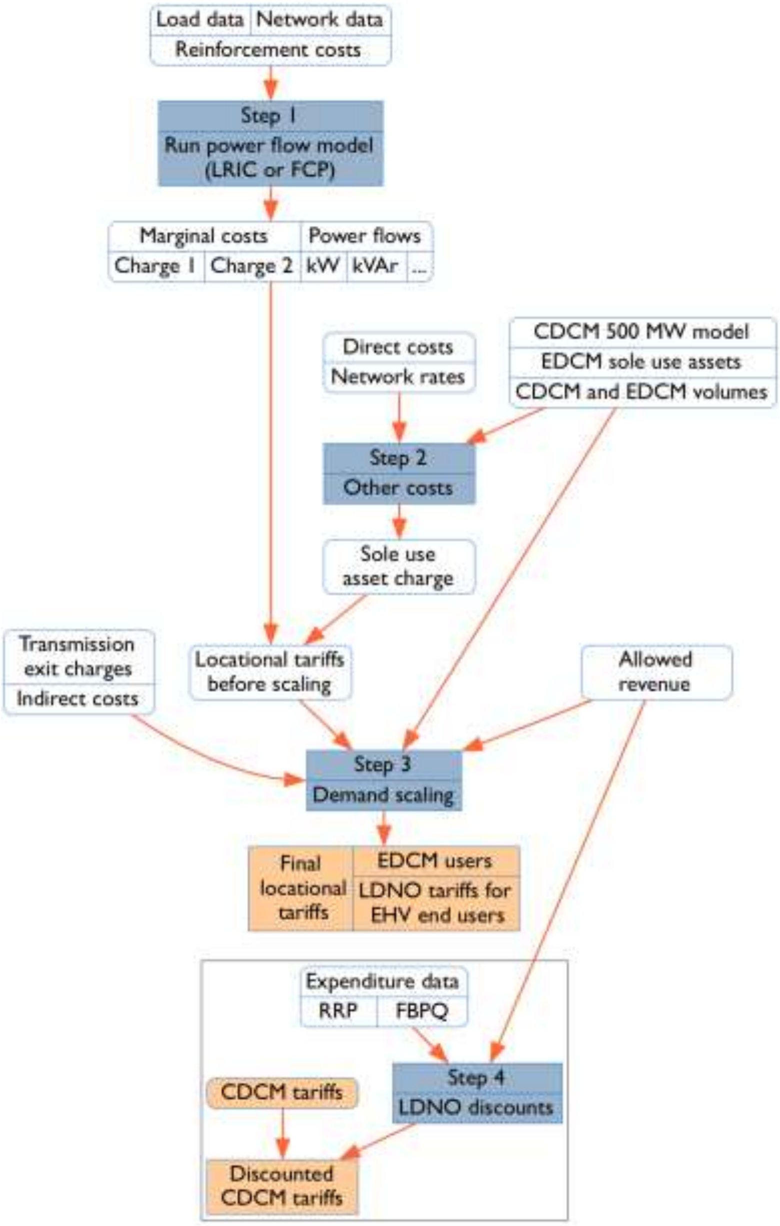
1.6 Step 2 involves the allocation of DNO Party costs to Connectees using appropriate cost drivers.

1.7 Step 3 adds a scaling element to charges which is related to Allowed Revenue.

1.8 Step 4 uses CDCM charges to determine the element of portfolio charges to be applied in the case of DNO/IDNO Parties who are supplied from the DNO Party's network at voltages higher than the scope of CDCM charges.

1.9 Figure 1 provides a diagrammatic overview of the steps involved for import charges.

Figure 1 Diagrammatic overview of the EDCM for import



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; and

(f) calculation of FCP load 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 (save that, until 5 November 2016, where charges are being calculated for two or more Regulatory Years, the same Authorised Network Model will be used for all the years).

2.4 Guidance on the configuration of the Authorised Network Model is provided in the section 4 (**Error! Reference source not found.**~~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 (**Error! Reference source not found.**~~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.

Calculation of reinforcement costs

2.13 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.

2.14 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

2.15 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.

2.16 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 EDCM 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:

FCPload	=	FCP load incremental charge (£/kVA/annum)
j	=	in index of Branch whose reinforcement is required in the planning period
i	=	discount rate, which is set to equal the latest pre-tax real weighted average cost of capital (CC below) for each DNO Party calculated using the following formula:

CC = (Gearing Assumption x Pre-Tax Cost of Debt) + (1- Gearing Assumption)*(Post Tax Cost of Equity/(1-Corporation Tax Rate))

where:

Gearing Assumption is set to the ‘notional Gearing’ value referred to in the ED1 Price Control Financial Handbook;

Pre-Tax Cost of Debt is set to the ‘cost of corporate debt’ value specified in or calculated in accordance with the most recent Annual Iteration Process applicable when setting distribution Use of System Charges;

Post Tax Cost of Equity is set to the ‘cost of equity’ value referred to in the ED1 Price Control Financial Handbook; and

Corporation Tax Rate is the rate of corporation tax which is, when setting distribution Use of System Charges, expected to be applicable in respect of the Regulatory Year in which those Charges will take effect.

The CC value is calculated as a percentage, and rounded to two decimal places.

Aj = 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

Cl = total demand (kVA) of the Network Group, in the Maximum Demand Scenario, in the year Yl 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

gl = 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

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

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

Where:

gl = annual average load growth rate corresponding to the year in which the reinforcement is expected to be required

Yl = number of years before the reinforcement of Branch "j" is required

Cl = total demand (kVA) of the Network Group, in the Maximum Demand Scenario, in the year Yl 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

2.18 Guidance relating to the calculation and application of FCP load incremental charges is presented in section 9.1 (**Error! Reference source not found.**~~FCP load incremental charge~~) of Annex 1.

Outputs

2.19 The outputs of the FCP modelling are:

(a) Network Group ID;

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

(c) Parent Network Group ID;

(d) Active Power (kW) of demand (load) for Maximum Demand Scenario;

(e) Reactive Power (kVAr) of demand (load) for Maximum Demand Scenario;

(f) Active Power (kW) of demand (generation) for Maximum Demand Scenario; and

(g) Reactive Power (kVAr) of demand (generation) for Maximum Demand Scenario.

3. EDCM CHARGE COMPONENTS FOR CONNECTEES

3.1 This section sets out the different charge components that will apply to Connectees under the EDCM. Charge components are the outputs of the EDCM and make up the distribution use of system charges applied to Connectees.

3.2 In the EDCM, each set of charges comprises import rates, export rates, or both, as applicable to the Connectee. The DNO Party's Relevant Charging Statement includes information that enables a Supplier to determine which Designated EHV Property each set of charges applies to.

3.3 Demand charges under the EDCM comprise the following individual components:

Import fixed charges.

Import capacity charges.

Exceeded import capacity charges.

Unit rate charges for consumption at the time of the DNO Party's peak (super-red time band).

3.4 The EDCM charge components for import are listed in table 1.

Table 1 Charge components for import

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

3.5 Generation charges under the EDCM comprise the following individual components:

Export fixed charges

Export capacity charges

Exceeded export capacity charges

Export super-red unit rate (credit)

3.6 The EDCM charge components for export are listed in table 2.

Table 2 Charge components for export

Charge component	Unit
Export fixed charge	p/day
Export capacity charge	p/kVA/day
Exceeded export capacity charge	p/kVA/day
Export super-red unit rate	p/kWh

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

4. CALCULATION OF EDCM CHARGE COMPONENTS

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

5. CHARGEABLE EXPORT CAPACITY FOR EXPORT CHARGES

5.1 The Chargeable Export Capacity for each Connectee is defined as the Maximum Export Capacity minus any capacity that is exempt from use of system charges in the charging year.

6. APPLICATION OF FCP CHARGE 1

6.1 Each tariff in the model is linked to one FCP location or network group. Each FCP network group may be linked to a parent FCP network group and a grandparent FCP network group. Each FCP network group may have a charge 1 in £/kVA/year associated with it.

6.2 The import charges for the application of charge 1 is given by the formulas:

For Connectees 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 Connectees:

[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.

Any negative contributions to the [p/kVA/day capacity charge] or the [p/kWh super-red rate] from the parent or the grandparent network groups are set to zero.

Super red hours are the number of hours in the DNO Party'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 Party to reflect the time of peak, and then divided by the Maximum Import Capacity (averaged over the same financial year). If the DNO Party considers that the reactive consumption data relates to export rather than import (e.g. the average kVAr figure exceeds half of the Maximum Import Capacity) then the Maximum Import Capacity in the denominator should be replaced by the Maximum Export Capacity of the same Connectee. 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.

6.3 Charge 1 is applied to export charges as a credit. The credit is expressed as a negative charge rate in p/kWh and is applied in respect of active power units exported during the DNO Party's super-red time band. The credit rate is set to zero for Connectees who are assigned an F Factor of zero. The credit rate is calculated as follows:

[p/kWh super-red export rate] = -100*[Proportion eligible for charge 1 credits] *([network charge 1 £/kVA/year] + [parent charge 1 £/kVA/year] + [grandparent charge 1 £/kVA/year]) * ([Chargeable export capacity]/[Maximum export capacity]) /[number of hours in the super-red time band]

Where:

The proportion eligible for charge 1 credits is zero if the F factor that is assigned to the Connectee as described in the FCP methodology is equal to zero, and 1 otherwise.

The super-red generation rate is not applied to Connectees with zero Chargeable Export Capacity.

7. NO APPLICATION OF NEGATIVE CHARGES

7.1 Under FCP, charge 1 is either zero or positive. Any negative values of Charge 1 are set to zero.

8. DEMAND SIDE MANAGEMENT (DSM) AND GENERATION SIDE MANAGEMENT (GSM)

8.1 Some EDCM Customers are subject to demand side management (DSM) or generation side management (GSM) agreements.

8.2 For Connectees 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 Connectees 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.

8.4 For Connectees with GSM agreements, no adjustments are made in the EDCM.

9. TRANSMISSION CONNECTION (EXIT) CHARGES FOR DEMAND

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 * NETSO charge / (CDCM system maximum load + total EDCM peak time consumption)

Where:

DC is the number of days in the Charging Year.

NETSO charge is the DNO Party's forecast annual expenditure on transmission connection point charges in £.

CDCM system maximum load is the forecast system simultaneous maximum load from CDCM Connectees (in kW) from CDCM table 2506.

Total EDCM peak time consumption (in kW) calculated by multiplying the Maximum Import Capacity of each Connectee by the forecast peak-time kW divided by forecast maximum kVA of that Connectee (adjusted for losses to transmission and, if necessary, for Connectees connected for part of the Charging Year) and aggregating across all EDCM Customer demand.

9.3 The single p/kW/day charging rate is converted into a p/kVA/day import capacity based charge for each EDCM Connectee as follows:

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

10. TRANSMISSION CONNECTION (EXIT) CREDITS FOR GENERATORS

10.1 A capacity-based credit related to transmission exit is applied to generation tariffs.

10.2 Transmission exit credits are paid to generators that have an agreement with the DNO, the terms of which require the generator, for the purposes of P2/6 compliance, to export power during supergrid transformer (SGT) outage conditions.

10.3 The rate in p/kVA/day for each generation customer would be calculated as follows:

Transmission exit credit p/kVA/day = -[Transmission exit charging rate in p/kW/day] * [Capacity eligible for credits in kW] / [Chargeable Export Capacity in kVA of that Connectee]

Where:

Transmission exit charging rate in p/kW/day is calculated as described for demand tariffs.

Capacity eligible for credits (in kW) is the capacity that is made available by the generator under the agreement with the DNO.

Chargeable Export Capacity (in kVA) is the forecast average value of the maximum export capacity of the generator over the charging year, less any capacity that is exempt from use of system charges in the charging year.

The generation transmission connection (exit) rate is not calculated for Connectees with zero Chargeable Export Capacity.

10.4 Transmission connection (exit) credits are applied to the Chargeable Export Capacity (in kVA)

11. REACTIVE POWER CHARGES

11.1 The EDCM does not include a separate charge component for any reactive power flows.

12. EXPORT CAPACITY CHARGES

12.1 The EDCM includes an export capacity charge.

12.2 EDCM DG revenue target £/year = GL * [Total 2005-2010 EDCM generation capacity] / ([Total 2005–2010 EDCM generation capacity] + [Total 2005–2010 CDCM generation capacity]) + AGPa * [Total post–2010 EDCM generation capacity] / ([Total post–2010 EDCM generation capacity] + [Total post–2010 CDCM generation capacity]) + (OM * ([Total Pre–2005 EDCM DG capacity] + [Total Post–2010 EDCM DG capacity]))

Where:

GL is the incentive revenue in the charging year in respect of generators connected between 2005 and 2010 calculated for the charging year as in paragraph 11.10 of the Special Conditions of the Electricity Distribution Licence (CRC11). From and including Regulatory Year 2015/2016 GL is zero.

AGPa is the average of the values of GPa for the charging year and each of the two years immediately preceding the charging year. For Regulatory Year 2014/2015 GPa is calculated using a modified version of the formula in paragraph 11.6 of the Electricity Distribution Licence (CRC11) resulting from DPCR5. To calculate GPa, the term GPX is replaced by the term GPS in the formula in paragraph 11.6. Both GPX and GPS are defined in paragraph 11.7 of the same document. For Regulatory Years 2015/16 onwards GPa is zero.

Total Pre-2005 EDCM DG capacity is the aggregate maximum export capacity of all non-exempt EDCM generators that connected before 1 April 2005, adjusted for part-year connected generators. In the case of generators that have subsequently increased their maximum export capacity, the part of their capacity that was added after 1 April 2005 would be ignored.

Total 2005–2010 EDCM generation capacity is the sum of the maximum export capacities of all non-exempt EDCM generators that connected between 1 April 2005 and 31 March 2010, adjusted for part-year connected generators.

Total Post–2010 EDCM generation capacity is the sum of the maximum export capacities of all non-exempt EDCM generators that connected on or after 1 April 2010, adjusted for part-year connected generators. In the case of generators that originally connected before 1 April 2010 and have increased their maximum export capacity on or after 1 April 2010, the capacity that was added after 1 April 2010 should be included.

Total 2005–2010 CDCM generation capacity is the sum of the maximum export capacities of all non-exempt CDCM generators that connected between 1 April 2005 and 31 March 2010, adjusted for part-year connected generators.

Total Post–2010 CDCM generation capacity is the sum of the maximum export capacities of all non-exempt CDCM generators that connected on or after 1 April 2010, adjusted for part-year connected generators.

OM is an allowance in £/kW in respect of the operational and maintenance costs for assets that are deemed to have been installed for the purposes of connecting generators to the distribution network. The value of OM is set to £0.20/kW.

12.3 A fixed export capacity charge in p/kVA/day is calculated as follows:

Fixed export capacity charge in p/kVA/day = (100 / DC) * [EDCM DG revenue target] / [Total EDCM generation capacity]

Where:

EDCM DG revenue target in £/year is calculated as described above

Total EDCM generation capacity (in kVA) is the aggregate Chargeable Export Capacity of all Connectees, adjusted, if necessary for Connectees connected part of the year.

The fixed export capacity charge in p/kVA/day is applied to the Chargeable Export Capacity of each EDCM Connectee.

13. ALLOCATION DRIVERS FOR OTHER CHARGE ELEMENTS IN THE EDCM

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

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

13.2 The residual revenue is that part of the DNO Party's Allowed Revenue that has not been pre-allocated to demand charges using cost-based charge elements.

13.3 EDCM charge 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 Connectee (sole use assets). This is relevant to import and export charges.
- The value of site-specific shared network assets used by the Connectee. This is relevant to import charges only.
- The sum of historical consumption at the time of system peak and 50 per cent of Maximum Import Capacity. This is relevant to import charges only.
- Chargeable Export Capacity. This is relevant to export charges only.

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

14. SOLE USE ASSETS

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

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

14.3 The Point of Common Coupling for a particular single Connectee is the point on the network where the power flow associated with the single Connectee under consideration, may under some (or all) possible arrangements interact with the power flows associated with other Connectees, taking into account all possible credible running arrangements.

14.4 Where a single site has both import and export charges, associated with import and export meter registrations, the sole use assets are allocated between the import and export proportionally to Maximum Import Capacity and Maximum Export Capacity respectively. Where any part of the Maximum Export Capacity associated with an export meter registration is exempt from use of system charges in the charging year, the value of sole use assets allocated to the export tariff is reduced by multiplying it by the ratio of the Chargeable Export Capacity to the Maximum Export Capacity.

14.5 Where an EDCM site was originally connected as a single Connected Installation, and has subsequently split into multiple Connected Installations, 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 Connected Installations in proportion to their Maximum Import Capacities and Maximum Export Capacities.

15. SITE-SPECIFIC SHARED NETWORK ASSETS

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

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

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

15.4 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.

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

15.6 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 Point of Common Coupling. The Point of Common Coupling might be at a different voltage than the Connectee's connection, and might also be at a different voltage than the voltage of connection when the Connectee was connected.

Table 3 Categorisation of EDCM Customers

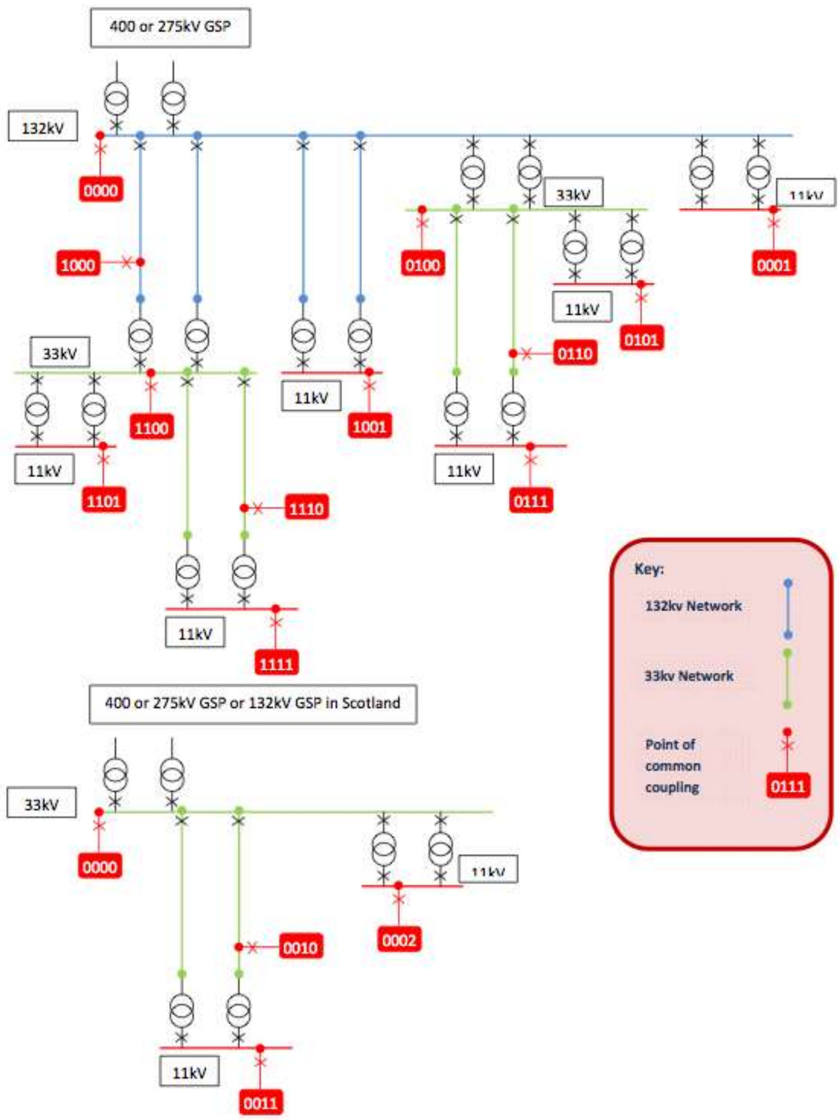
Category	Definition
Category 0000	Point of Common Coupling at the GSP, whether the GSP is shared or not.
Category 1000	In England or Wales only, Point of Common Coupling at a voltage of 132 kV, unless the Connectee qualifies for category 0000.
Category 1100	Point of Common Coupling at 22 kV or more on 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.

15.7 All references to GSP in the table above relate to interconnections with the onshore National Electricity Transmission System.

15.8 The figure below provides examples of Connectees who might be placed in each of the categories described above.

Customer Categories



15.9 The use of each network level by each EDCM Connectee 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

15.10 Category 0000 Connectee are deemed not to use any network assets other than sole use assets.

15.11 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 Import Capacity of the Connectee, and for network levels above on consumption at peak time.

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

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

Where:

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

DL 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 EDCM Customer category of that Connectee. See table below for the correspondence between EDCM 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 (0.95) by the loss adjustment factor to transmission for the network level relevant to that Connectee (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)

15.12 Again, separate site-specific asset values per kVA (in £/kVA) are calculated in respect of each network level. The asset value for the network level of connection is based on the Maximum Import Capacity of the Connectee, and for network levels above on consumption at peak time.

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

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

Where:

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

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.

15.13 Network use factors for import charges 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. DNO Parties 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.

15.14 The total value of the site-specific shared assets required to serve each Connectee 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 Connectee.

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

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

15.15 Total site-specific shared assets is the aggregate value (in £) of all site-specific shared assets for EDCM Connectees. This is calculated by multiplying TNA by the Maximum Import Capacity (adjusted, if necessary, for Connectees connected for part of the Charging Year), and then aggregating across all EDCM Connectees.

16. CALCULATION OF THE EDCM DEMAND REVENUE TARGET

16.1 The EDCM demand revenue target is the share of the DNO Party’s Allowed Revenue (excluding transmission exit charges and net revenue from EDCM generation) that will be recovered from EDCM Connectees through import charges.

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

16.3 A single contribution rate for network rates is calculated for all EDCM Connectees 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 DNO Party's total expenditure on network rates.

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

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectees.

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.

16.4 A single contribution rate for direct operating costs is calculated for all EDCM Connectees 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 DNO Party's total expenditure on direct operating costs.

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

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectees.

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.

16.5 A single contribution rate for indirect costs is calculated for all EDCM Connectees 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 DNO Party's total expenditure on indirect costs.

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

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectees.

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.

16.6 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 Party's total Allowed Revenue excluding transmission exit charges in £/year

DOC is the DNO Party's total expenditure on direct operating costs.

INDOC is the DNO Party's total expenditure on indirect costs.

NR is the DNO Party's total expenditure on network rates.

GCN is the total forecast net revenue in £/year from the application of EDCM export charges, including the EDCM generation fixed charge. This amount is estimated by applying the calculated EDCM export charges rounded to the relevant number of decimal points.

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

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

HV and LV network assets from the CDCM model.

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

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

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

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

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

Where:

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

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 Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

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

Demand sole use asset based network rates contribution = S * NR rate

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

Demand sole use asset based indirect costs contribution = S * INDOC rate

Where

S is the MEAV of demand sole use assets of that EDCM Connectee (adjusted for Connectees 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.

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

16.10 The aggregate EDCM demand revenue target is calculated as the sum, across all EDCM demand, of the contributions based on import capacities and demand sole use assets, less the total reduction in fixed charges made to EDCM customers under paragraph 17.2. Such fixed charge reduction is to be derived as follows:

FCR = OMR * (EHV assets + HV and LV network assets) / (Total site-specific shared assets + EHV assets + HV and LV network assets)

Where

OMR is the total reduction in fixed charges made to EDCM customers under paragraph 17.2, where the reduction is derived as the aggregated value of the amount each EDCM customer would have paid under paragraph 17.1 less the amount paid under 17.2 for eligible customers.

17. FIXED CHARGES FOR IMPORT AND EXPORT

17.1 The contribution rates for network rates and direct operating costs are converted into a p/day fixed charge for the sole use assets of each EDCM Connectee as follows:

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

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

Where

DC is the number of days in the Charging Year.

SD is the MEAV of sole use assets allocated to demand of that EDCM Connectee.

SG is the MEAV of sole use assets allocated to generation of that EDCM Connectee excluding the value of sole use assets associated with exempt export capacity.

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.

17.2 Where a customer demonstrates with written evidence to the DNO Party (or where the DNO Party has written evidence) that the customer (or its predecessors) made a capitalised O&M payment in respect of a connection to the DNO Party's network, and the period over which the O&M payment was capitalised remains unexpired, then the import fixed charge will be calculated as set out below (and the calculation for the import fixed charge in paragraph 17.1 will not apply).

The sole use assets will be split between those where capitalised O&M has been paid and those where it has not, and the fixed charge will be derived as follows:

p/day = (((DOC rate + NR rate) * SUA MEAVU) + (NR rate * SUA MEAVP)) / (days in Charging Year) * 100

Where:

DOC rate is the direct operating costs contribution rate in per cent;
NR rate is the network rates contribution rate in per cent;
Where SUA MEAVU is the Modern Equivalent Asset Value of Sole Use Assets where capitalised O&M has not been paid (or the period over which it was to be capitalised has expired); and

SUA MEAVP is the Modern Equivalent Asset Value of Sole Use Assets where capitalised O&M has been paid (and the period over which it was to be capitalised has not expired).

17.3 For customers that are classified as exempt pre-2005 EDCM Distributed Generators (DGs), it is deemed for the purposes of paragraph 17.2 that the customer paid capitalised O&M to be capitalised over a period of 25 years from connection.

18. DEMAND SCALING

18.1 Demand scaling is the process by which import charges to EDCM Connectees are set so that the forecast notional recovery from the application of those import charges to EDCM Connectees matches the EDCM demand revenue target.

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

- Calculating adjusted site-specific shared asset values for each Connectee 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 Connectees on the basis of adjusted site-specific assets and sole use assets. [a]
- Allocation of the indirect cost element in the EDCM demand revenue target to individual EDCM Connectees on the basis of their consumption at the time of the DNO Party's peak and 50 per cent of Maximum Import Capacity as a p/kVA/day charge. [b]
- Forecasting the notional recoveries from the application of FCP charges to EDCM Connectee. [c]
- Allocation of 80 per cent of the difference between the EDCM demand revenue target and the sum of 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.

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

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

- In ascending order, list the network use factors for all EDCM Connectees in all DNO Party 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 EDCM Connectee.
- 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.

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

18.6 The network use factor (NUF) caps and collars for 2011/2012 and each network level were calculated using this methodology and are set out in table 4 below. The NUF caps and collars using 2015/2016 data for each network level have also been determined, and are set out in table 4A below.

Table 4 Network use factor caps and collars (2011/2012)

Network levels	Collar	Cap
132kV	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	2.678

Table 4A Network use factor caps and collars (using 2015/16 data)

Network levels	Collar	Cap
132kV	0.192	1.859
132kV/EHV	0.674	1.551
EHV	0.367	2.366
EHV/HV	0.635	1.616
132kV/HV	0.808	1.652

18.7 The caps and collars in table 4 above were fixed for three years, and were used to calculate charges for the Charging Years 2012/2013 and 2013/2014. The caps and collars are to be re-calculated for the subsequent Charging Years. From Charging Year 2017/2018 onwards the caps and collars are to be calculated using the methodology described in paragraph 18.5 based on the NUFs described in paragraph 18.8. The NUFs themselves are calculated in accordance with paragraphs 29 and 30 below.

18.8 Table 5 below sets out the schedule for the calculation of the NUF caps and collars for each Charging Year.

Table 5 NUF cap and collar calculation timeline

Charging Year	**Caps and collars**
2011/2012 Submission	2011/2012 caps/collars (as per table 4)
2012/2013	2011/2012 caps/collars (as per table 4)
2013/2014	2011/2012 caps/collars (as per table 4)
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	2015/2016 caps/collars (as per table 4A)
2018/2019	2015/2016 caps/collars (as per table 4A)
2019/2020	2015/2016 caps/collars (as per table 4A)
2020/2021	Average of 2015/2016, 2016/2017, 2017/2018 NUFs
2021/2022	Average of 2015/2016, 2016/2017, 2017/2018 NUFs
2022/2023	Average of 2015/2016, 2016/2017, 2017/2018 NUFs
2023/2024	Average of 2017/2018, 2018/2019, 2019/2020, NUFs
2024/2025	Average of 2017/2018, 2018/2019, 2019/2020, NUFs
2025/2026	Average of 2017/2018, 2018/2019, 2019/2020 NUFs

18.9 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 Import Capacity of the EDCM Connectee, and for network levels above on consumption at peak time.

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

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

Where:

NUaL is the adjusted network use factor for that EDCM Connectee 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.

18.10 The total value of the adjusted site-specific shared assets required to serve each EDCM Connectee 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 EDCM Connectee.

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

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

18.11 Total adjusted site-specific shared assets for all EDCM demand is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM Connectees. This is calculated by multiplying TNAa by the Maximum Import Capacity (adjusted, if necessary, for Connectees connected for part of the Charging Year), and then aggregating across all EDCM demand.

18.12 The direct cost and network rates allocations to individual demand Connectees 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.

18.13 A single asset based charging rate for network rates is calculated for all EDCM Connectee. 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 Connectee.

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

18.14 A single asset based charging rate for direct operating costs is calculated for all EDCM Connectees. 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 Connectee.

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

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

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 EDCM Connectee.

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

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

18.16 A p/kVA/day charging rate for indirect costs for each EDCM Connectee is calculated on the basis of historical demand at the time of the DNO Party's peak and 50 per cent of Maximum Import Capacity of that Connectee.

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 EDCM Connectees.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by Maximum Import Capacity in kVA of that Connectee (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 Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

LDNO factor takes the value 0.5 if the EDCM Connectee is connected to a LDNO's network 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 Connectee.

18.17 The p/kVA/day charging rate for indirect costs is converted into an import capacity based charge for each EDCM Connectee 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 Distribution System-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 Import Capacity in kVA of that Connectee (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 EDCM Connectee is connected to a LDNO's network and 1 otherwise.

18.18 A single asset based residual revenue charging rate is calculated for all EDCM Connectees. 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 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 Connectee.

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

SU recovery is the forecast notional recovery from the application of import fixed charges (before any rounding) for sole use assets relating to EDCM Connectees.

FCP recovery is the forecast notional recovery from the application of FCP demand charges (before any rounding) to all EDCM Connectees.

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

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

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 EDCM Connectee.

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

18.20 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 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 Connectee (from annex 3).

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

SU recovery is the forecast notional recovery from the application of demand fixed charges (before any rounding) for sole use assets relating to EDCM Connectees.

FCP recovery is the forecast notional recovery from the application of FCP demand charges (before any rounding) to all EDCM Connectees 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 Connectee (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 Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

18.21 The fixed adder in p/kVA/day is converted into an import capacity based charge for each EDCM Connectee as follows:

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

Where:

Fixed adder is the Distribution System-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 Import Capacity in kVA of that Connectee (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)).

19. APPLICATION OF EDCM DEMAND FOR EDCM CONNECTEES

19.1 The tariff application rules for the EDCM are the same as for the CDCM wherever possible. Each component of each tariff is rounded to the nearest value with no more than three decimal places in the case of unit rates expressed in p/kWh, and with no more than two decimal places in the case of fixed and capacity charges expressed in p/day and p/kVA/day respectively.

19.2 The part of EDCM portfolio tariffs (for LDNO networks and Distribution Licence exempt networks) that is based on CDCM tariffs will be billed like CDCM tariffs.

19.3 Final EDCM demand charges will have:

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

19.4 The import fixed charge on sole use assets in p/day is applied to each EDCM Connectee.

19.5 The final EDCM import capacity charge for each EDCM Connectee 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]

19.6 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.

19.7 If the EDCM import capacity charge (p/kVA/day) calculated above is negative and the Connectee's average kW/kVA (adjusted for part year) 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]))

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

19.9 Final EDCM export charges will have:

1. An export fixed charge on sole use assets (in p/day)
2. An export capacity charge (in p/kVA/day), which might include transmission exit credits to qualifying generators.
3. An export super-red unit rate (in p/kWh)
4. An exceeded export capacity charge (in p/kVA/day)

19.10 The export capacity charge (in p/kVA/day) is applied to the Chargeable Export Capacity of EDCM Connectees.

19.11 The export super-red unit rate (in p/kWh) is applied to active power units exported during the DNO Party's super-red time band.

20. EXCEEDED CAPACITY CHARGES

20.1 Where a Connectee uses additional capacity over and above the Maximum Import Capacity or Maximum Export Capacity without authorisation, the excess is classed as exceeded capacity.

20.2 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

Export capacity used = 2 * (SQRT(AE^2 + MAX(RI,RE)^2))

Where:

AE = Import consumption in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

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

20.4 For the purposes of calculating exceeded capacity for export charges, any reactive flows during half hours when there is no active power export will not be taken into account.

20.5 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 Party would not be taken into account when calculating import or export capacity used.

20.6 For Connectees other than those that have an agreement with the DNO, the terms of which require them, for the purposes of P2/6 compliance, to export power during supergrid transformer (SGT) outage conditions, the exceeded portion of the export capacity is charged at the same rate as the capacity that is within the Maximum Export Capacity. This is charged for the duration of the month in which the breach occurs.

20.7 For Connectees other than those with DSM agreements, the exceeded portion of the import capacity is charged at the same rate as the capacity that is within the Maximum Import Capacity. This is charged for the duration of the month in which the breach occurs.

20.8 Sites subject to DSM arrangements would normally pay the DSM-adjusted capacity charge for capacity usage up to their Maximum Import Capacities.

20.9 If sites with DSM agreements were to exceed their maximum import 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.

21. APPLICATION OF EDCM IMPORT CHARGE COMPONENTS

21.1 Table 6 summarises the method of application of import charge components.

Table 6 Application of EDCM import charge components

Tariff component	Unit	Application
Import 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)
Import super-red unit rate	p/kWh	Applied to active power units consumed during the DNO Party's super-red time band.

21.2 Table 7 summarises the method of application of export charge components.

Table 7 Application of EDCM export charge components

Tariff component	Unit	Application
Export fixed charge	p/day	Applied as a fixed charge.
Export capacity charge	p/kVA/day	Applied to the Chargeable Export Capacity.
Exceeded export 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)

Tariff component	Unit	Application
Export super-red unit rate	p/kWh	Applied to active power units exported during the DNO Party's super-red time band.

22. CHARGES FOR NEW CONNECTEES

22.1 New Connectees could connect at any time between the publication of EDCM charges for the new Charging Year and the end of that Charging Year.

22.2 If the connection of such Connectees had been anticipated before the publication of charges, the DNO Party would have included forecast data relating to the new Connectee in both the power flow model and the EDCM tariff model. The resulting tariff is applied to the new Connectee, on a pro-rata basis if the price is produced during the Charging Year.

22.3 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 Connectee, failing that, make a reasonable estimate;

Run the power flow model after including the new Connectee to produce a full set of charges 1 and 2, including for the new Connectee;

Include the new Connectee's details, including marginal charges from (a) in the EDCM tariff model, to produce a full set of new charges;

Use the tariff relating to the new Connectee to calculate charges; and

Charges relating to the current year for existing Connectees would not change as a result.

22.4 If a Connectee were to change their maximum import or export capacity at any time between the publication of EDCM charges 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.

23. DNO TO DNO CHARGES

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

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

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

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

(c) All other interconnections between DNO Parties.

23.2 In all cases of type (a), the benefitting DNO Party will be treated as being equivalent to an EDCM Connectee connected to the other DNO Party's network. The DNO Party providing the benefit will calculate and apply EDCM import charges, except charges for sole use assets, as applicable to the other DNO Party. Export charges or credits will not apply.

23.3 In the case of type (b) interconnections, each DNO Party will treat the other as an EDCM Connectee. Normal EDCM import charges, except charges for sole use assets, will apply. Export charges or credits will not apply.

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

23.5 In every other case, each DNO Party applies import charges to the other as a normal EDCM Connectee, as with type (b) interconnections.

24. LDNO CHARGING

24.1 LDNOs with Distribution Systems that serve Connectees 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 charges.

A LDNO with a Distribution System that qualifies as a CDCM "Designated Property" according to the definition set out in condition 13A.6 of the Distribution Licence is eligible for portfolio discounts calculated using a price control disaggregation model (method M) consistent with the CDCM.

A LDNO with a Distribution System that qualifies as an EDCM "Designated EHV Property" according to the definition set out in condition 13B.6 of the Distribution Licence is eligible for discounts calculated using an "extended" price control disaggregation model (extended method M).

24.2 A LDNO with a Distribution System that qualifies as an EDCM "Designated EHV Property" could itself have Connectees who would fall under the scope of the EDCM. Since the EDCM is a locational charging method, the host DNO Party would calculate EDCM charges at the DNO Party's boundary for each EDCM-like Connectee on the LDNO's Distribution System. No discounts are calculated for such EDCM Connectees as the DNO Party's charges are based only on the specific site's equivalent use of the DNO Party's Distribution System.

25. CALCULATION OF LDNO DISCOUNTS

25.1 The discount percentages are determined in accordance with Schedule 29, which is deemed to form part of this EDCM (as if it were set our therein).

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

25.3 Not used.

25.4 Not used.

25.5 Not used.

25.6 Not used.

25.7 Not used.

25.8 Not used.

25.9 Not used.

25.10 Not used.

25.11 Not used.

25.12 Not used.

25.13 Not used.

25.14 Not used.

25.15 Not used.

25.16 Not used.

25.17 Not used.

25.18 Not used.

25.19 Not used.

26. PORTFOLIO EDCM TARIFFS FOR CONNECTEES IN THE EDCM

26.1 For Connectees on a LDNO's Distribution System that would be covered by the EDCM if they were on the DNO Party's Distribution System, the EDCM is applied to calculate a portfolio EDCM charge/credit for each such Connectee.

26.2 These EDCM portfolio charges would be calculated as if each EDCM Connectee on the LDNO's Distribution System were notionally connected at the boundary between the DNO Party and the LDNO; except for LDNO UMS tariffs, which are charged by reference to the voltage of the Points of Connection that provide the majority of the energised domestic connections for the LDNO in the GSP Group (or, where there is no such majority, on such other reasonable basis as the DNO Party determines). Both EDCM import and export charges will apply.

26.3 For the purposes of calculating the boundary-equivalent portfolio EDCM tariffs, each EDCM Connectee on the LDNO's Distribution System would be assigned the demand Connectee category determined by reference to that LDNO Distribution System's Point of Common Coupling. The demand Connectee category is assigned as per Table 3 in paragraph 15.6.

26.4 Such Connectees would attract charges (credits) in respect of any reinforcements caused (avoided) on the DNO Party's Distribution System only, i.e. any network Branches that are on the LDNO's Distribution System would be attributed a zero FCP charge/credit.

26.5 The setting of final charges to Embedded Designated EHV Properties including the calculation of charges for assets used on the LDNO's Distribution System will be established by the LDNO.

26.6 All EDCM charges would be calculated using "boundary equivalent" data provided by the LDNO to the host DNO Party 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 Party - LDNO boundary, for each EDCM Connectee, after taking into consideration the diversity and losses within the LDNO's Distribution System. 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.

26.7 The EDCM will include in the charges for Embedded Designated EHV Properties a fixed charge relating to any assets on the DNO Party's Distribution System that are for the sole use of a LDNO's Distribution System. The assets on the DNO Party's network that are for the sole use of a LDNO Distribution System are defined as the assets in which only consumption or output associated with Embedded customers on the LDNO Distribution System can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements, i.e. all assets between the asset ownership boundary and the LDNO Distribution System's Point of Common Coupling are considered as sole use assets. These fixed charges would be calculated in the same way as it would be for EDCM Connectees connected directly to the host DNO Party's Distribution System.

26.8 In calculating charges for assets on the DNO Party's Distribution System that are for the sole use of a LDNO's Distribution System, DNO Parties 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 Connectee to the capacity at the LDNO - DNO Party boundary.

26.9 If there are no Embedded Designated EHV Properties on the LDNO's Distribution System, no sole use asset charges would apply.

26.10 Demand scaling would be applied as normal to any EDCM portfolio tariff in respect of an EDCM Connectee. For the purposes of scaling, all EDCM Connectees connected to the LDNO's Distribution System will be treated as notional EDCM Connectees connected to the DNO Party's Distribution System with a Point of Common Coupling at the LDNO Distribution System's Point of Common Coupling.

26.11 For EDCM Connectees connected to the LDNO's Distribution System, the capacity-based charge for the DNO Party's indirect costs and the 20% share of residual revenue that is applied as a fixed adder, would be scaled down by a factor of 50 per cent, however, the scaling down will not apply where the residual revenue is negative.

27. OFFSHORE NETWORKS CHARGING

27.1 The DNO Party will treat offshore networks connected to the DNO Party as if they were EDCM Connectees.

27.2 The DNO Party 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.

27.3 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 Connectee.

27.4 Demand scaling will also be applied.

28. DNO PARTY TO LICENCE EXEMPT SYSTEMS~~UNLICENSED NETWORKS~~

28.1 Not used. ~~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.~~

28.2 Otherwise, the DNO Party applies the EDCM to calculate an import and export charge based on ~~capacity and~~ power flow data ~~metered~~ at the boundary and agreed capacity 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 Connectee.~~

28.2A The tariffs charged in respect of Licence Exempt Systems~~unlicensed networks~~ using Difference Metering shall be charged to the Supplier at the DNO Party's boundary based on the units imported or exported at the boundary between the network and the Licence Exempt Systems~~unlicensed network~~. No charges will be applied by the DNO Party to the boundary settlements data received by the DNO Party, or to the settlements data received in respect of the settlements meter within the Licence Exempt System~~unlicensed network~~.

28.2B **The tariffs charged in respect of** Licence Exempt Systems **using Fully Settled metering shall be charged to the Supplier at the DNO Party's boundary**

28.3 Licence Exempt Systems that serve Connectees 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 charges.

Commented [RC13]: Change unlicensed networks to licence exempt systems

Commented [RC14]: Replicate changes within PNO rebate for sceh 17 and 18.

Commented [RC15]: NK to provide an example to include:

- Summate metering data from conectees to understand when consumption being used
- Power flow analysis to determine tariff
- Allocation to each connectee

Commented [RC18]: Need to explain how this is determined.

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28.4 Tariffs for customers connected to Licence Exempt Systems are determined in accordance with paragraph 88a of schedule 16, save that lower voltage elements are excluded as follows:

- where the Licence Exempt System is connected at an EHV/HV substation, the costs associated with the LV customer, LV network, LV substation and HV network levels are excluded;
- where the Licence Exempt System is connected to the EHV network, the costs associated with the LV customer, LV network, LV substation, HV network and EHV/HV levels are excluded;
- where the Licence Exempt System is connected at a 132kV/EHV substation, the costs associated with the LV customer, LV network, LV substation, HV network, EHV/HV and EHV network levels are excluded;
- where the Licence Exempt System is connected to the 132kV network, the costs associated with the LV customer, LV network, LV substation, HV network, EHV/HV, EHV network and 132kV/EHV levels are excluded;
- where the Licence Exempt System is connected direct to a GSP, the costs associated with the LV customer, LV network, LV substation, HV network, EHV/HV, EHV network, 132kV/EHV and 132kV network levels are excluded.

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28.4A Capacity charge elements (p/kVA/day) for half-hourly site-specific settled customers connected to Licence Exempt Systems are allocated to the fixed charge (in p/day) by multiplying the capacity charge by the average kVA per customer for an equivalent all-the-way customer, determined from the DNO Party's volume forecast for the equivalent all-the-way half-hourly metered tariff at that voltage as determined under schedule 16.

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28.4B Reactive power charge elements (p/kVArh) for half-hourly site-specific settled customers connected to Licence Exempt Systems are allocated to the fixed charge (in p/day) by multiplying the reactive power charge by the average kVArh per customer for an equivalent all-the-way customer, determined from the DNO Party's volume forecast for the equivalent all-the-way half-hourly metered tariff at that voltage as determined under schedule 16, and dividing by the number of days in the charging year.

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29. DERIVATION OF 'NETWORK USE FACTORS'

Step 1:

29.1 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 EDCM demand or CDCM demand at the EHV/HV boundary.

29.2 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)

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

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

30. INCREMENTAL METHOD:

30.1 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.

30.2 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 Connectee 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.

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

Step 2:

30.4 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:

30.5 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:

30.6 Each nodal demand’s proportionate usage of a Branch is determined using the equation below:

Alloc (£/year) = ([MW usage] / [Total MW usage]) * (Abs [Max contingency flow] / [Rating]) * AMEAV

If the Branch is “generation-dominated”, or (2 * Abs [Base flow load]) ≤ Abs ([Base flow] - [Base flow load]), then use:

Alloc (£/year) = ([MW usage] / [Total MW usage]) * (Abs [Max contingency flow] / [Rating]) * Abs ([Base flow load] / [Base flow]) * AMEAV

Where:

- Alloc is the allocation of the AMEAV of the asset to a demand user in £/year
- MW usage is the absolute value of the “MW usage” of the asset attributable to that demand user (expressed in MW)
- Total MW usage is the sum of the absolute values of the “MW usage” of all demand users of that asset (expressed in MW)

- Max contingency flow is the maximum post-contingent flow through the asset in MVA. The maximum post-contingency asset flows may be extracted from the 'locational' analyses.

- Rating is the unadjusted rated capacity of the asset in MVA

- Base flow load is the algebraic sum of power flows through the Branch due to demand only in MW.

- Base flow is the aggregate power flow through the Branch under normal network operation in MW.

- AMEAV is the annualised modern equivalent asset value in £/year of that asset.

- The ratio ([Max contingency flow] / [Rating]) is called the asset utilisation factor and it is capped at 1.

The quantity (Abs [Max contingency flow] / [Rating]) * Abs ([Base flow load] / [Base flow]) is called the load utilisation factor.

30.7 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:

30.8 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'.

30.9 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.

30.10 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 Party 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.

30.11 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.

SCHEDULE 18 – EHV CHARGING METHODOLOGY (LRIC MODEL)

This Schedule 18, version 10.0, is to be used for the calculation of Use of System Charges which will become effective from, 01 April 2018 and remain effective until superseded by a revised version.

1. INTRODUCTION

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

1.2 This Schedule 18 sets out the methods, principles, and assumptions underpinning the EDCM for the calculation of Use of System Charges by the following DNO Parties:

Eastern Power Networks plc;

Electricity North West Limited;

London Power Networks plc;

Northern Powergrid (Northeast) Limited;

Northern Powergrid (Yorkshire) plc;

South Eastern Power Networks plc;

Western Power Distribution (South Wales) plc; and

Western Power Distribution (South West) plc.

1.3 In order to comply with this methodology statement when setting distribution Use of System Charges the DNO Parties referred to above will populate the EDCM model version L204 when issued by the Panel in accordance with Clause 14.5.3.

Main steps

1.4 The EDCM involves four main steps.

1.5 Step 1 is the application of load flow techniques and the LRIC or FCP methodologies to determine an EDCM tariff element, known as Charge 1, which represents costs associated with demand-led reinforcement, estimated by reference to power flows in the maximum demand scenario.

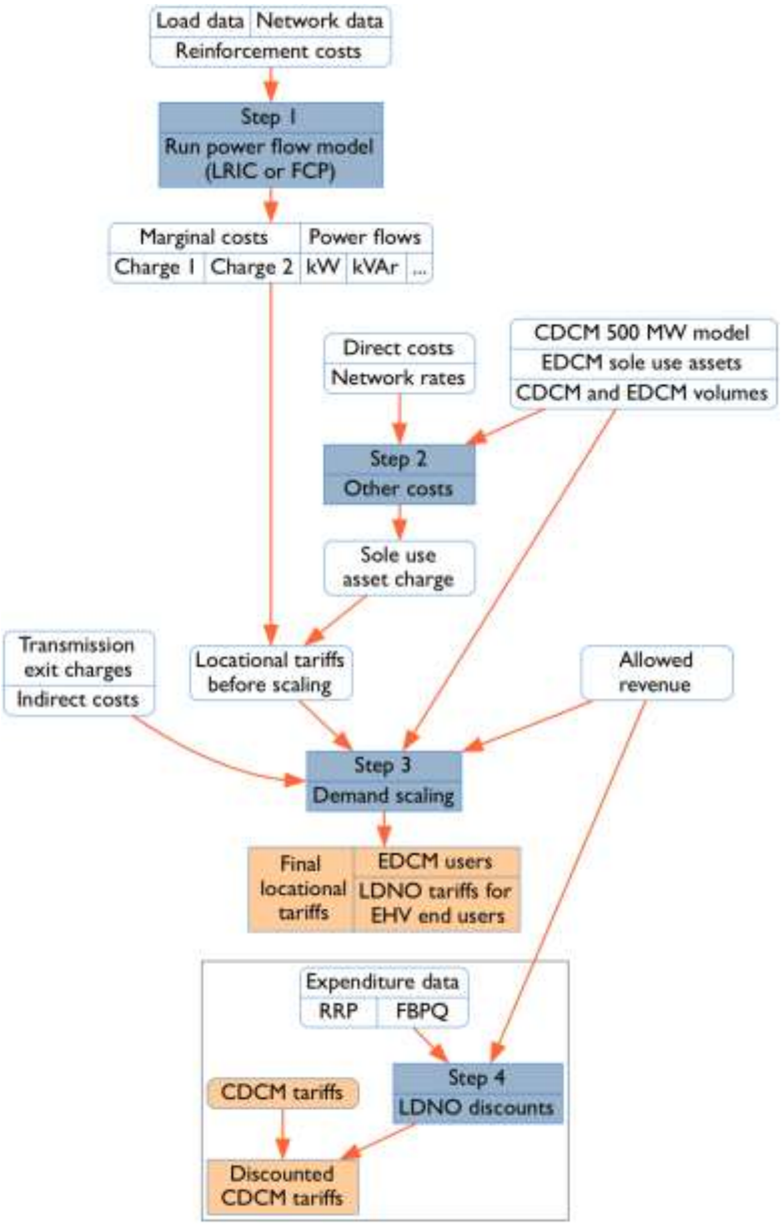
1.6 Step 2 involves the allocation of DNO Party costs to Connectees using appropriate cost drivers.

1.7 Step 3 adds a scaling element to charges which is related to Allowed Revenue.

1.8 Step 4 uses CDCM charges to determine the element of portfolio charges to be applied in the case of DNO/IDNO Parties who are supplied from the DNO Party's network at voltages higher than the scope of CDCM charges.

1.9 Figure 1 provides a diagrammatic overview of the steps involved for import charges.

Figure 1 Diagrammatic overview of the EDCM for import



2. LONG RUN INCREMENTAL COST PRICING ANALYSIS

Introduction

2.1 This Schedule 18 sets out the principles and high-level detail that should be adopted as the common approach to EDCM Use of System Charging that is based on the Long Run Incremental Cost (LRIC) model.

2.2 The LRIC model calculates Nodal incremental costs. These costs represent the brought forward (or deferred) reinforcement costs caused by the addition of an increment of demand or generation at each network Node. The method models the impact changes in Connectees' behaviour have on network costs.

2.3 In particular, the LRIC model takes account of the effects a change in Connectee behaviour has on the network by using AC power flow analysis, which enables the calculation of the time needed before elements of the network require reinforcement and subsequently the net present value (NPV) of the future costs of reinforcement. The incremental cost is equal to the difference in the NPV of reinforcing under existing conditions and when an increment of new demand or generation is added.

2.4 To calculate Use of System Charges for EDCM Connectees (demand and generation), the common LRIC method consists of the following stages:

(a) LRIC model:

(i) AC power flow analysis;

(ii) calculation of Branch incremental costs (in £/annum); and

(iii) calculation of Nodal incremental costs (including the consideration of the Maximum Demand Scenario and the Minimum Demand Scenario; in £/annum);

(iv) calculation of Nodal, Charge 1 (by taking account of the magnitude of the increment driving the incremental costs; in £/kVA/annum).

(b) derivation of site-specific Use of System Charges (including the consideration of sole use asset charges, transmission exit charges and operating and maintenance costs); and

(c) scaling to derive the final EHV Use of System Charges.

Power Flow Analysis

2.5 Power flow analysis calculates the effects of adding an increment of demand or generation to the DNO Party's Distribution System. In particular, it calculates the power flows passing over the various assets comprising the DNO Party's network under base and incremented conditions using maximum (typically during the winter period) and minimum (typically during the summer period) demand data.

2.6 The power flow analysis calculates the following values for each Node/Branch combination:

(a) base power flows using Maximum Demand Data and Minimum Demand Data, and

(b) incremented power flows using Maximum Demand Data and Minimum Demand Data.

2.7 Power flow analysis uses a number of processes and assumptions as follows:

(a) A representation of the entire EHV network captured using appropriate power flow modelling software (the Authorised Network Model)[1]. The modelled network should be based on the network expected to exist and be in operation in the Regulatory Year that Use of System Charges are being calculated for, based on the DNO Party's Long Term Development Statement (save that, until 5 November 2016, where charges are being calculated for two or more Regulatory Years, the same Authorised Network Model will be used for all the years).

(b) AC power flows should be calculated for maximum and minimum demand base conditions and for maximum and minimum demand conditions plus an increment of demand or generation[2]. A 0.1MW Nodal increment should be used in relation to calculating the active demand and generation elements of the incremented power flows, assuming that the power factor is 0.95 for

[1] Guidance on creation of a suitable network model is provided in section 4**Error! Reference source not found.**~~Authorised Network Model~~ of Annex 1.

[2] Guidance on the power-flow analysis required to consider these conditions is provided in sections 6.3 and 6.10 of Annex 1.

increments applied at Nodes where demand is located and unity for increments applied at Nodes where generation is located. Increments will be applied in the direction of demand for the analysis of maximum demand network conditions and in the direction of generation for the analysis of minimum demand conditions. Where both demand (load) and generation are located at a Node, separate incremental power flows shall be calculated using increments at 0.95 power factor and at unity power factor.

(c) Nodal demand and generation data should be used, which is based on actual metered network usage data that is recovered from the DNO Party's Supervisory Control and Data Acquisition (SCADA) (or equivalent) system. In particular:

(i) **Demand Data** – for the maximum demand period, the model uses demands consistent with those used to assess reinforcement[3]. This includes diversity to allow a complete EHV network model to be run[4]. Minimum demands are taken as being a percentage of maximum demands[5]. This percentage is derived for each Grid Supply Point (GSP) and applied to the demands supplied by that GSP;

(ii) **Generation Data** - for the maximum demand period generation is zero unless it is deemed to contribute to network security in accordance with ER P2/6[6]. The generation export used for the minimum demand period is the Maximum Export Capacity for each EDCM (Generation) Connectee, factored to reflect coincidence with other generation export. This factor is derived for each GSP and applied to EDCM (Generation) Connectees connected to that GSP. These are broadly similar to the assumptions that are used by the DNO Party when investment planning[7];

(iii) **Cleansing Data** - the DNO Party should cleanse demand and generation data so that it is representative of typical network usage. That is,

[3] Guidance on the demand data required to represent the maximum demand period is provided in section 5.31 of Annex 1.
[4] Guidance on the application of diversity to demand data is provided in section 5.11 of Annex 1.
[5] Guidance on the demand data required to represent the minimum demand period is provided in section 5.37 of Annex 1.
[6] Guidance on the generation data required to represent the maximum demand period is provided in section 5.31 of Annex 1.
[7] Guidance on the generation data required to represent the minimum demand period is provided in section 5.37 (of Annex 1

anomalous power flows, which represent, for example, demand levels at a time when the network is experiencing an outage, should be removed from the data set and the effects of load management schemes should be taken account of[8];

(iv) **Growth Rate** - a single underlying network growth rate is used to assess the timing of future reinforcement for both demand and generation Connectees. It represents the long run growth of all DNO Parties' networks and is set to 1% growth per annum. To facilitate predictability and stability, the growth rate is used throughout the model, and (as with all assumptions) the DNO Party should keep this growth rate under review. As a minimum, the rate should be reviewed and reset when the charge restriction conditions in the DNO Party's Distribution Licence are reviewed every five years; and

(v) **Security Factors** - a pair of Security Factors should be determined[9] for each Branch using a full N-1 Contingency Analysis assuming maximum and minimum demand conditions[10]. These factors are used to determine the usable capacity of network Branches during maximum and minimum demand conditions. They are recalculated each time the network is changed or new load estimates used. Each N-1 Contingency will consider the consequential network actions and where appropriate constraints on Connectee demands (both generation and load) to meet the security of supply requirements of E/R P2/6.

(d) The results of the power flow analysis are sense checked to identify where application of Security Factors to the incremented power flows leads to excessively large (and non-credible) estimations of the change in Branch utilisation. The following conditions are identified:

(i) low base power flows;

(ii) high Security Factors; and

[8] Guidance on suitable cleansed demand data is provided in section 5.2 of Annex 1
[9] Guidance on the derivation of Security Factors is provided in section 6.6 of Annex 1.
[10] Guidance on the Contingency Analysis used in the derivation of Security Factors is provided in section 6.4 of Annex 1.

(iii) where the difference between the base and incremented Branch power flows exceeds the change that could reasonably be expected to occur as a result of the application of an increment of demand or generation.

(e) Where such cases are encountered a modified approach to the anticipated change in power flow in the Branch is used. Guidance on the sense checking of the power flow analysis results is provided in section **Error! Reference source not found.**~~8.3~~of **Error! Reference source not found.**~~Annex 1~~. This approach does not apply the Security Factor when considering the change in flow between the incremented and the base case power flow.

Calculation of Branch incremental costs

2.8 The incremental cost of reinforcing a Branch due to an increment at a Node is the difference in the net present value (NPV) of reinforcing the Branch under base and incremented conditions. An explanation of the derivation of the formulae used to calculate Branch incremental costs is provided in Annex 2.

2.9 The Branch incremental cost, denoted ΔC_i, is calculated using the following formulae:

$$\Delta C_i = [NPV(inc) - NPV(base)]_i \cdot AnnuityRate$$

$$NPV(inc) = \frac{CostOfReinforcementSolution}{[1 + DiscountRate]^{YearsToReinforcement(inc)}}$$

$$NPV(base) = \frac{CostOfReinforcementSolution}{[1 + DiscountRate]^{YearsToReinforcement(base)}}$$

$$YearsToReinforcement(base) = \frac{\log(BranchCapacity) - \log(BasePowerFlow(MVA))}{\log(1 + GrowthRate)}$$

$$YearsToReinforcement(inc) = \frac{\log(BranchCapacity) - \log(IncPowerFlow(MVA))}{\log(1 + GrowthRate)}$$

$$AnnuityRate = \frac{DiscountRate}{1 - \left[\dfrac{1}{(1 + DiscountRate)^{AnnuityPeriod}}\right]}$$

Branch Capacity is the MVA rating of the "critical" asset in the considered Branch divided by the corresponding Security Factor; a pair of Branch capacities is calculated for maximum demand and minimum demand conditions. Guidance on Branch ratings is provided in section **Error! Reference source not found.**~~7.5~~ of **Error! Reference source not found.**~~Annex 1~~. Guidance on sense checking Security Factors prior to the calculation of Branch incremental costs is provided in section **Error! Reference source not found.**~~8.3~~ of **Error! Reference source not found.**~~Annex 1~~.

$\boldsymbol{CostofReinforcementSolution}$ is the modern equivalent asset value (MEAV) of reinforcing the particular Branch, bearing in mind the requirements of similar historic projects. This cost is the same under both base and incremented conditions. The DNO Party should use the specifications and costs of similar, past reinforcement projects as a means for determining the requirements and costs of a particular future reinforcement project. Guidance on the reinforcement cost calculation principles is provided in section **Error! Reference source not found.**~~7.4~~ of **Error! Reference source not found.**~~Annex 1~~.

YearsToReinforcement is the number of years into the future when reinforcement of the Branch will be required. This is calculated separately under base and incremented conditions.

$\boldsymbol{DiscountRate}$ is set to equal the latest pre-tax real weighted average cost of capital (CC below) for each DNO Party calculated using the following formula:

CC = (Gearing Assumption x Pre-Tax Cost of Debt) + (1- Gearing Assumption)*(Post Tax Cost of Equity/(1-Corporation Tax Rate))

where:

Gearing Assumption is set to the 'notional Gearing' value referred to in the ED1 Price Control Financial Handbook;

Pre-Tax Cost of Debt is set to the 'cost of corporate debt' value specified in or calculated in accordance with the most recent Annual Iteration Process applicable when setting distribution Use of System Charges;

Post Tax Cost of Equity is set to the 'cost of equity' value referred to in the ED1 Price Control Financial Handbook; and

Corporation Tax Rate is the rate of corporation tax which is, when setting distribution Use of System Charges, expected to be applicable in respect of the Regulatory Year in which those Charges will take effect.

The CC value is calculated as a percentage, and rounded to two decimal places.

GrowthRate is the growth rate in per units of the power flow, currently set at 1%.

$\boldsymbol{AnnuityPeriod}$ is the period over which costs are annuitised. This period is set to 40 years and represents the typical life of an asset.

2.10 Separate assessment of the total Branch cost recovery associated with incremental costs that represent charges, PositiveCostRecovery, and the total Branch recovery associated with incremental costs that represent credits, NegativeCostRecovery, is done to eliminate over-recovery of both the charges and credits.

2.11 Two total Branch cost recoveries, namely PositiveCostRecovery and NegativeCostRecovery, are derived from the power-flow modelling and sense checked for each Branch individually. Guidance on sense checking of overall positive and negative Branch cost recoveries is provided in section **Error! Reference source not found.**~~8.3~~ of **Error! Reference source not found.**~~Annex 1~~.

2.12 The positive Branch cost recovery for a particular Branch is calculated by adding together the cost recovery for the Branch at each Node where the incremental cost is positive (i.e. 'charge', determined by the product of the positive Branch incremental costs and the appropriate Nodal demands, or generation output, used in the modelled network).

2.13 Similarly, the negative Branch cost recovery is calculated for the Branch where each Node incremental cost is negative (i.e.'credits', determined by the product of the negative Branch incremental costs and the appropriate Nodal demands, or generation output, used in the modelled network).

2.14 Both sense checks only consider Branch incremental costs associated with the period that drives reinforcement. Where either the positive or the negative (by absolute value) cost recovery for a particular Branch is greater than the actual reinforcement cost of the Branch (ActualReinforcementCost, as determined by the product of the Annuity Rate and the CostofReinforcementSolution), then it is considered that the Branch recovery of charges or credits is excessive.

2.15 In order to limit the level of positive Branch cost recovery (charges) to being no greater than the actual reinforcement cost of the Branch, a Positive Cost Recovery Factor, s_{P_i}, is applied to the positive Branch incremental costs associated with Branch i, when used in the calculation of Nodal incremental costs. Similarly, a Negative Cost Recovery Factor, sNi, is applied to the negative Branch incremental costs associated with Branch i in order to limit the level of negative Branch cost recovery (credits).

2.16 Where the positive cost recovery associated with Branch i (ie charges) is determined by the sense checking, to be excessive then:-

$$s_{Pi} = \text{ActualReinforcementCost}_i \,/\, \text{PositiveCostRecovery}_i$$

otherwise:-

$$s_{Pi} = 1$$

Where the negative cost recovery associated with Branch i (i.e. credits) is determined to be excessive, then:-

$$s_{Ni} = \mathit{ActualReinforcementCost_i/NegativeCostRecovery_i}$$

$$s_{Ni} = 1.$$

2.17 The EHV network includes single Connectees using sole-use assets that have been sized to their connection requirements. Costs for these assets should be excluded from the calculation of incremental costs. Replacement and operation and maintenance costs for these assets should also be excluded from the calculation of incremental costs, but may be incorporated into a Connectee’s final Use of System Charge.

<u>Calculation of Nodal incremental costs</u>

2.18 Guidance on the calculation of Nodal incremental costs, is provided in section 8 (Output results) of Annex 1. The formulae used to calculate Nodal incremental costs are described in Annex 2.

2.19 A pair of incremental costs (one for the Maximum Demand Scenario and another for the Minimum Demand Scenario) is calculated for each Node by summating Branch incremental costs that result from applying an increment at that Node. A peak Nodal incremental cost is calculated by summating Branch peak incremental costs, where maximum demand conditions drive Branch reinforcement. An off-peak Nodal incremental cost is calculated by summating Branch off-peak incremental costs, where minimum demand conditions drive Branch reinforcement. Only Branches that experience a change greater than both 1kVA and 0.01 % of Base Power Flow in the power that flows across them are used in the calculation of Nodal charges. The period that is deemed to drive reinforcement is the period with the highest absolute incremental cost.

2.20 The formulaic expression for Nodal incremental cost is given by:

$$IncrementalCostAtNode^{Peak} = \sum_{i \in \alpha} s_i \cdot \Delta C_i^{Peak}, \ \alpha = \left\{1,2,...B \middle| \left|\Delta C_i^{Peak}\right| > \left|\Delta C_i^{Off-Peak}\right|\right\}$$

$$IncrementalCostAtNode^{Off-Peak} = \sum_{i \in \beta} s_i \cdot \Delta C_i^{Off-Peak}, \ \beta = \left\{1,2,...B \middle| \left|\Delta C_i^{Peak}\right| < \left|\Delta C_i^{Off-Peak}\right|\right\}$$

where

$$\Delta C_i^{Peak} = [NPV(inc) - NPV(base)]_i^{Peak} \cdot AnnuityRate$$

$$\Delta C_i^{Off-Peak} = [NPV(inc) - NPV(base)]_i^{Off-Peak} \cdot AnnuityRate$$

ΔC_i^{Peak} and $\Delta C_i^{Off-Peak}$ denote the incremental cost of reinforcing Branch *i*, under maximum and minimum demand conditions respectively, due to an increment of demand or generation at the Node;

s_i denotes the Recovery Factor for Branch *i*;

B is the total number of Branches in the network;

α and β are subsets of Branches where relevant conditions are satisfied.

Calculation of Nodal marginal charges for demand

2.21 Guidance on the calculation of Nodal marginal charges for demand sites is provided in section **Error! Reference source not found.**~~8.12~~ (**Error! Reference source not found.**~~Demand Nodes~~) of **Error! Reference source not found.**~~Annex 1~~.

2.22 The Nodal incremental costs for demand sites are derived using Branch incremental costs produced by application of 0.1MW increments at 0.95 power factor, which is equivalent to 0.10526MVA. The Nodal marginal charges for demand in (£/kVA/annum) are obtained by dividing the Nodal incremental cost for each period by the absolute value of the kVA increment:

$$\text{ChargeAtNode}^{\text{Peak}} = \text{IncrementalCostAtNode}^{\text{Peak}} / 105.26 \text{ (£/kVA/annum)}$$

2.23 A positive value of ChargeAtNodePeak represents a charge for demand sites at the Node, whereas a negative value represents a credit. This statement defines the sign convention of the Nodal marginal charges (as outlined in section **Error! Reference source not found.**~~8~~ (**Error! Reference source not found.**~~Output results~~) of **Error! Reference source not found.**~~Annex 1~~ and Attachment 3 (**Error! Reference source not found.**~~Output results~~) to **Error! Reference source not found.**~~Annex 1~~. However, it should be noted that this does not describe the application of these charges in the calculation of final Use of System Charges (or credits in respect of final Use of System Charges).

Generation sites

2.24 Guidance on the calculation of Nodal marginal charges for generation sites is provided in section **Error! Reference source not found.**~~8.13~~ (**Error! Reference source not found.**~~Generation Nodes~~) of **Error! Reference source not found.**~~Annex 1~~.

2.25 The Nodal incremental costs for generation sites are derived using Branch incremental costs produced by application of 0.1MW increments at unity power factor being equal to 0.1MVA. The Nodal marginal charges for generation are obtained by dividing the Nodal incremental cost for each period by the absolute value of the kVA increment:

$$\text{ChargeAtNode}^{\text{Peak}} = \text{IncrementalCostAtNode}^{\text{Peak}} / 100 \text{ (£/kVA/annum)}$$

2.26 A positive value of ChargeAtNodePeak represents a credit for generation sites at the Node, whereas a negative value represents a charge. This statement defines the sign convention of the Nodal marginal charges (as outlined in section **Error! Reference source not found.**~~8~~ (**Error! Reference source not found.**~~Output results~~) of **Error! Reference source not found.**~~Annex 1~~ and Attachment 3 (**Error! Reference source not found.**~~Output results~~) to **Error! Reference source not found.**~~Annex 1~~. However, it should be noted that this does not describe the application of these charges in the calculation of final Use of System Charges (or credits in respect of final Use of System Charges).

Decomposition of Nodal marginal charges

2.27 Each Nodal marginal charge, derived from the Nodal incremental costs, is decomposed into two sub-elements, termed 'local' and 'remote', such that:-

$$\text{ChargeAtNode}^{\text{Peak}} = \text{LocalChargeAtNode}^{\text{Peak}} + \text{RemoteChargeAtNode}^{\text{Peak}}$$

2.28 The local element of each charge at a Node is derived from:-

(a) the Branch incremental costs associated with Branches that are operating at the same nominal voltage as the voltage of the Node where the increment was applied; and

(b) the Branch incremental costs associated with Branches that represent transformation from a higher voltage down to the same nominal voltage as the voltage of the Node where the increment was applied.

2.29 The remote element of each Nodal incremental cost is derived from the Branch incremental costs from all Branches other than those where the Branches are operating at the same nominal voltage as the voltage of the Node where the increment was applied, or where the Branches represent transformation from a higher voltage down to the same nominal voltage as the Node. In other words, all Branches that are not 'local' are 'remote'.

Outputs from LRIC Analysis

2.30 The LRIC methodology produces the following outputs:

(a) Location (Node);

(b) Demand Type (Generation or Load);

(c) Local Charge 1: LocalChargeAtNodepeak (£/kVA/annum);

(d) Remote Charge 1: RemoteChargeAtNodepeak (£/kVA/annum);

(e) Active Power (kW) for the Maximum Demand Scenario;

(f) Reactive Power (kVAr) for the Maximum Demand Scenario;

3. EDCM CHARGE COMPONENTS FOR CONNECTEES

3.1 This section sets out the different charge components that will apply to Connectees under the EDCM. Charge components are the outputs of the EDCM and make up the distribution use of system charges applied to Connectees.

3.2 In the EDCM, each set of charges comprises import rates, export rates, or both, as applicable to the Connectee. The DNO Party's Relevant Charging Statement includes information that enables a Supplier to determine which Designated EHV Property each set of charges applies to.

3.3 Demand charges under the EDCM comprise the following individual components:

Import fixed charges.

Import capacity charges.

Exceeded import capacity charges.

Unit rate charges for consumption at the time of the DNO Party's peak (super-red time band).

3.4 The EDCM charge components for import are listed in Table 1.

Table 1 Charge components for import

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

3.5 Generation charges under the EDCM comprise the following individual components:

Export fixed charges

Export capacity charges

Exceeded export capacity charges

Export super-red unit rate (credit)

3.6 The EDCM charge components for export are listed in Table 2.

Table 2 Charge components for export

Charge component	Unit
Export fixed charge	p/day
Export capacity charge	p/kVA/day
Exceeded export capacity charge	p/kVA/day
Export super-red unit rate	p/kWh

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

4. CALCULATION OF EDCM CHARGE COMPONENTS

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

5. CHARGEABLE EXPORT CAPACITY FOR EXPORT CHARGES

5.1 The Chargeable Export Capacity for each Connectee is defined as the Maximum Export Capacity minus any capacity that is exempt from use of system charges in the charging year.

6. APPLICATION OF LRIC CHARGE 1

6.1 Each tariff in the model is linked to one LRIC location or point. Each LRIC point may have a local and remote charge 1 in £/kVA/year associated with it.

6.2 Some LRIC points might be designated as linked. Each set of linked points comprises a maximum of eight points. Where a tariff is associated with a point which is part of a set of linked points, the LRIC charge 1 used for that tariff are determined by calculating the applicable local and remote charge 1 as a weighted average of the local and network charge 1 respectively at each linked point (ignoring negative values) using the kVA modelled flow in the maximum demand run as weights. If all the weights are zero in any of these calculations then an unweighted average is used instead of the weighted average.

6.3 The import charges for the application of charge 1, is given by the formulas:

[p/kWh super-red rate] = (([remote charge 1 £/kVA/year] / PF) / [number of hours in the super-red time band in a year]) * 100

[p/kVA/day capacity charge] = ([local charge 1 £/kVA/year] /[days in Charging Year])*100

Where:

PF is the power factor of the flow at the point at which the customer is attached in the maximum demand scenario. This is calculated as - [Active power flow] /

(SQRT([Active power flow]^2 + [Reactive power flow]^2). If either the numerator or denominator in calculation of the power factor is zero, the PF is replaced with 1. If the active power flow is generation-dominated, then PF is replaced with 1.

6.4 If the Connectee is attached to a cluster of linked locations, the sums of active power flows and reactive power flows at each location are used to calculate PF.

6.5 Charge 1 is applied to export charges as a credit. The credit is expressed as a negative charge rate in p/kWh and is applied in respect of active power units exported during the DNO Party's super-red time band. The credit rate is set to zero for Connectees who are assigned an F Factor of zero. The credit rate is calculated as follows:

[p/kWh super-red export rate] = -100*[Proportion eligible for charge 1 credits]*([local charge 1 £/kVA/year] + [remote charge 1 £/kVA/year]) * ([Chargeable export capacity]/[Maximum export capacity]) /[number of hours in the super-red time band]

Where:

The proportion eligible for charge 1 credits is zero if the F factor that is assigned to the Connectee as described in the LRIC methodology is equal to zero, and 1 otherwise.

The super-red export rate is not applied to Connectees with zero Chargeable Export Capacity.

7. NO APPLICATION OF NEGATIVE CHARGES

7.1 Under LRIC, charge 1 can be negative at some locations. Any negative values of Charge 1 (both local and remote) are set to zero.

8. DEMAND SIDE MANAGEMENT (DSM) AND GENERATION SIDE MANAGEMENT (GSM)

8.1 Some EDCM Customers are subject to demand side management (DSM) or generation side management (GSM) agreements.

8.2 For Connectees 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 Connectees with DSM agreements, DSM-adjusted local and remote (or parent and grandparent) elements of the LRIC charge are calculated as the product of the ratio of "chargeable capacity" to Maximum Import Capacity and the unadjusted elements of the LRIC charge. Where the Maximum Import Capacity is zero, this ratio is set to 1. The DSM-adjusted local element of the LRIC charge 1 is applied to the Maximum Import Capacity, and the DSM-adjusted remote (or parent and grandparent) element of the LRIC charge 1 is applied to units consumed during the super-red time band.

8.4 For Connectees with GSM agreements, no adjustments are made in the EDCM.

9. TRANSMISSION CONNECTION (EXIT) CHARGES FOR DEMAND

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 * NETSO charge / (CDCM system maximum load + total EDCM peak time consumption)

Where:

DC is the number of days in the Charging Year.

NETSO charge is the DNO Party's forecast annual expenditure on transmission connection point charges in £.

CDCM system maximum load is the forecast system simultaneous maximum load from CDCM Connectees (in kW) from CDCM table 2506.

Total EDCM peak time consumption (in kW) calculated by multiplying the Maximum Import Capacity of each Connectee by the forecast peak-time kW divided by forecast maximum kVA of that Connectee (adjusted for losses to transmission and, if necessary, for Connectees connected for part of the Charging Year) and aggregating across all EDCM Customer demand.

The single p/kW/day charging rate is converted into a p/kVA/day import capacity based charge for each EDCM Connectees as follows:

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

10. TRANSMISSION CONNECTION (EXIT) CREDITS FOR GENERATORS

10.1 A capacity-based credit related to transmission exit is applied to generation tariffs.

10.2 Transmission exit credits are paid to generators that have an agreement with the DNO, the terms of which require the generator, for the purposes of P2/6 compliance, to export power during supergrid transformer (SGT) outage conditions.

10.3 The rate in p/kVA/day for each generation customer would be calculated as follows:

Transmission exit credit p/kVA/day = -[Transmission exit charging rate in p/kW/day] * [Capacity eligible for credits in kW] / [Chargeable Export Capacity in kVA of that Connectee]

Where:

Transmission exit charging rate in p/kW/day is calculated as described for demand tariffs.

Capacity eligible for credits (in kW) is the capacity that is made available by the generator under the agreement with the DNO.

Chargeable Export Capacity (in kVA) is the forecast average value of the maximum export capacity of the generator over the charging year, less any capacity that is exempt from use of system charges in the charging year.

10.4 The generation transmission connection (exit) rate is not calculated for Connectees with zero Chargeable Export Capacity.

10.5 Transmission connection (exit) credits are applied to the Chargeable Export Capacity (in kVA)

11. REACTIVE POWER CHARGES

11.1 The EDCM does not include a separate charge component for any reactive power flows.

12. EXPORT CAPACITY CHARGES

12.1 The EDCM includes an export capacity charge.

12.2 First, an EDCM generation revenue target would be calculated as follows:

12.3 EDCM DG revenue target £/year = GL * [Total 2005-2010 EDCM generation capacity] / ([Total 2005–2010 EDCM generation capacity] + [Total 2005–2010 CDCM generation capacity]) + AGPa * [Total post–2010 EDCM generation capacity] / ([Total post–2010 EDCM generation capacity] + [Total post–2010 CDCM generation capacity]) + (OM * ([Total Pre–2005 EDCM DG capacity] + [Total Post–2010 EDCM DG capacity]))

Where:

GL is the incentive revenue in the charging year in respect of generation connected between 2005 and 2010 calculated for the charging year as in paragraph 11.10 of the Special Conditions of the Electricity Distribution Licence (CRC11). From and including Regulatory Year 2015/2016 GL is zero.

AGPa is the average of the values of GPa for the charging year and each of the two years immediately preceding the charging year. For Regulatory Year 2014/2015 GPa is calculated using a modified version of the formula in paragraph 11.6 of the Electricity Distribution Licence (CRC11) resulting from DPCR5. To calculate GPa, the term GPX is replaced by the term GPS in the formula in paragraph 11.6. Both GPX and GPS are defined in paragraph 11.7 of the same document. For Regulatory Years 2015/16 onwards GPa is zero.

Total Pre-2005 EDCM DG capacity is the aggregate maximum export capacity of all non-exempt EDCM generators that connected before 1 April 2005, adjusted for part-year connected generators. In the case of generators that have subsequently increased their maximum export capacity, the part of their capacity that was added after 1 April 2005 would be ignored.

Total 2005–2010 EDCM generation capacity is the sum of the maximum export capacities of all non-exempt EDCM generators that connected between 1 April 2005 and 31 March 2010, adjusted for part-year connected generators.

Total Post–2010 EDCM generation capacity is the sum of the maximum export capacities of all non-exempt EDCM generators that connected on or after 1 April 2010, adjusted for part-year connected generators. In the case of generators that originally connected before 1 April 2010 and have increased their maximum export capacity on or after 1 April 2010, the capacity that was added after 1 April 2010 should be included.

Total 2005–2010 CDCM generation capacity is the sum of the maximum export capacities of all non-exempt CDCM generators that connected between 1 April 2005 and 31 March 2010, adjusted for part-year connected generators.

Total Post–2010 CDCM generation capacity is the sum of the maximum export capacities of all non-exempt CDCM generators that connected on or after 1 April 2010, adjusted for part-year connected generators.

12.4 OM is an allowance in £/kW in respect of the operational and maintenance costs for assets that are deemed to have been installed for the purposes of connecting generators to the distribution network. The value of OM is set to £0.20/kW.

12.5 A fixed export capacity charge in p/kVA/day is calculated as follows:

Fixed export capacity charge in p/kVA/day = (100 / DC) * [EDCM DG revenue target] / [Total EDCM generation capacity]

Where:

EDCM DG revenue target in £/year is calculated as described above

Total EDCM generation capacity (in kVA) is the aggregate Chargeable Export Capacity of all Connectees, adjusted, if necessary for Connectees connected part of the year.

12.6 The fixed export capacity charge in p/kVA/day is applied to the Chargeable Export Capacity of each EDCM Connectee.

13. ALLOCATION DRIVERS FOR OTHER CHARGE ELEMENTS IN THE EDCM

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

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

13.2 The residual revenue is that part of the DNO Party's Allowed Revenue that has not been pre-allocated to demand charges using cost-based charge elements.

13.3 EDCM charge 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 Connectee (sole use assets). This is relevant to import and export charges.
- The value of site-specific shared network assets used by the Connectee. This is relevant to import charges only. The sum of historical consumption at the

time of system peak and 50 per cent of Maximum Import Capacity. This is relevant to import charges only.

- Chargeable Export Capacity. This is relevant to export charges only.

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

14. SOLE USE ASSETS

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

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

14.3 The Point of Common Coupling for a particular single Connectee is the point on the network where the power flow associated with the single Connectee under consideration, may under some (or all) possible arrangements interact with the power flows associated with other Connectees, taking into account all possible credible running arrangements.

14.4 Where a single site has both import and export charges, associated with import and export meter registrations, the sole use assets are allocated between the import and export proportionally to Maximum Import Capacity and Maximum Export Capacity respectively. Where any part of the Maximum Export Capacity associated with an export meter registration is exempt from use of system charges in the charging year, the value of sole use assets allocated to the export tariff is reduced by multiplying it by the ratio of the Chargeable Export Capacity to the Maximum Export Capacity.

14.5 Where an EDCM site was originally connected as a single Connected Installation, and has subsequently split into multiple Connected Installations, 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 Connected Installations in proportion to their Maximum Import Capacities and Maximum Export Capacities.

15. SITE-SPECIFIC SHARED NETWORK ASSETS

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

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

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

15.4 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.

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

15.6 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 Point of Common Coupling. The Point of Common Coupling might be at a different voltage than the Connectee's connection, and might also be at a different voltage than the voltage of connection when the Connectee was connected.

Table 3 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 Connectee 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.

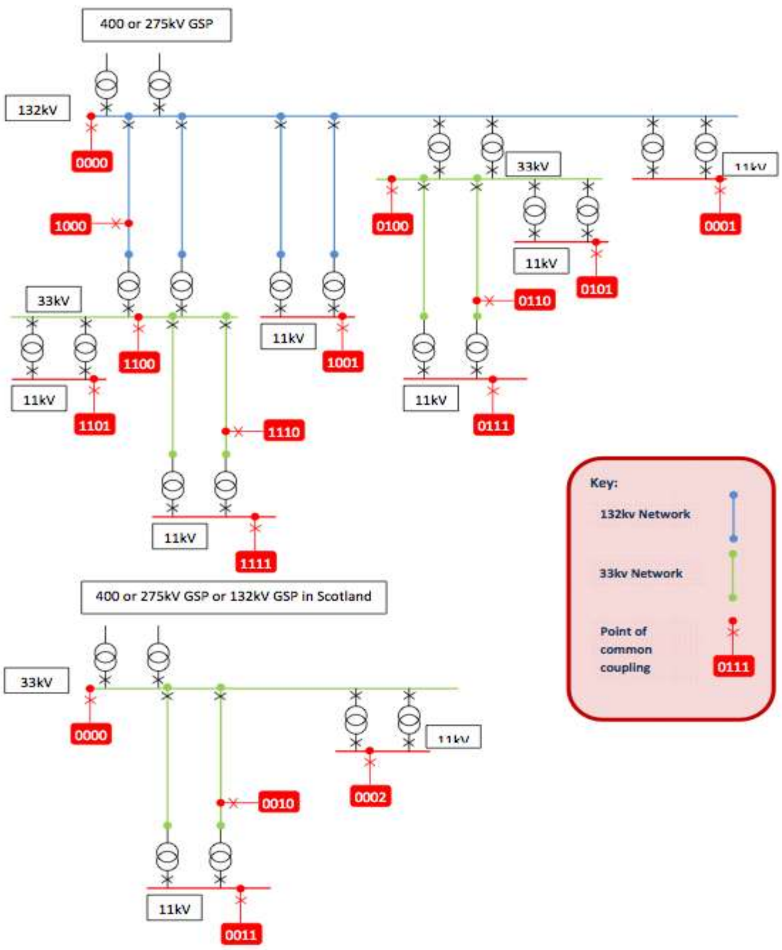
Category 0001	Point of Common Coupling at a voltage of less than 22 kV on the secondary side of a substation where the primary side is attached at 132 kV to a co-located GSP with no circuit.
Category 0002	Point of Common Coupling at a voltage of less than 22 kV on the secondary side of a substation where 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.

15.7 All references to GSP in the table above relate to interconnections with the onshore National Electricity Transmission System.

15.8 The figure below provides examples of Connectees who might be placed in each of the categories described above.

Customer Categories



15.9 The use of each network level by each EDCM Connectee 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

15.10 Category 0000 Connectees are deemed not to use any network assets other than sole use assets.

15.11 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 Import Capacity of the Connectee, and for network levels above on consumption at peak time.

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

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

Where:

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

DL 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 EDCM Customer category of that Connectee. See table below for the correspondence between EDCM 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 (0.95) by the loss adjustment factor to transmission for the network level relevant to that Connectee (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)

15.12 Again, separate site-specific asset values per kVA (in £/kVA) are calculated in respect of each network level. The asset value for the network level of connection is based on the Maximum Import Capacity of the Connectee, and for network levels above on consumption at peak time.

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

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

Where:

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

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.

15.13 Network use factors for import charges 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. Generation-dominated sites are determined according to the rules set out in the LRIC methodology to determine whether a location is to be modelled as a generation site.

15.14 The total value of the site-specific shared assets required to serve each Connectee 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 Connectee.

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

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

15.15 Total site-specific shared assets is the aggregate value (in £) of all site-specific shared assets for EDCM Connectees. This is calculated by multiplying TNA by the Maximum Import Capacity (adjusted, if necessary, for Connectees connected for part of the Charging Year), and then aggregating across all EDCM Connectees.

16. CALCULATION OF THE EDCM DEMAND REVENUE TARGET

16.1 The EDCM demand revenue target is the share of the DNO Party’s Allowed Revenue (excluding transmission exit charges and net revenue from EDCM generation) that will be recovered from EDCM Connectees through import charges.

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

16.3 A single contribution rate for network rates is calculated for all EDCM Connectees 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 DNO Party’s total expenditure on network rates.

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

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectees. 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.

16.4 A single contribution rate for direct operating costs is calculated for all EDCM Connectees 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 DNO Party’s total expenditure on direct operating costs.

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

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectees. 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.

16.5 A single contribution rate for indirect costs is calculated for all EDCM Connectees 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 DNO Party's total expenditure on indirect costs.

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

Total EDCM sole use assets is the aggregate sole use asset MEAVs of all EDCM Connectees, excluding the value of sole use assets associated with exempt export capacity, adjusted for part-year connected Connectee. 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.

16.6 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 Party's total Allowed Revenue excluding transmission exit charges in £/year

DOC is the DNO Party's total expenditure on direct operating costs.

INDOC is the DNO Party's total expenditure on indirect costs.

NR is the DNO Party's total expenditure on network rates.

GCN is the total forecast net revenue in £/year from the application of EDCM export charges, including the EDCM generation fixed charge. This amount is estimated by applying the calculated EDCM export charges rounded to the relevant number of decimal points.

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

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

HV and LV network assets from the CDCM model.

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

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

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

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

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

Where:

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

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 Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

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

Demand sole use asset based network rates contribution = S * NR rate

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

Demand sole use asset based indirect costs contribution = S * INDOC rate

Where

S is the MEAV of demand sole use assets of that EDCM Connectee (adjusted for Connectees 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.

16.9 The target contributions from import capacity and sole use assets are aggregated across all EDCM Connectees.

16.10 The aggregate EDCM demand revenue target is calculated as the sum, across all EDCM demand, of the contributions based on import capacities and demand sole use assets, less the total reduction in fixed charges made to EDCM customers under paragraph 17.2. Such fixed charge reduction is to be derived as follows:

FCR = OMR * (EHV assets + HV and LV network assets) / (Total site-specific shared assets + EHV assets + HV and LV network assets)

Where

OMR is the total reduction in fixed charges made to EDCM customers under paragraph 17.2, where the reduction is derived as the aggregated value of the amount each EDCM customer would have paid under paragraph 17.1 less the amount paid under 17.2 for eligible customers.

17. FIXED CHARGES FOR IMPORT AND EXPORT

17.1 The contribution rates for network rates and direct operating costs are converted into a p/day fixed charge for the sole use assets of each EDCM Connectee as follows:

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

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

Where

DC is the number of days in the Charging Year.

SD is the MEAV of sole use assets allocated to demand of that EDCM Connectee.

SG is the MEAV of sole use assets allocated to generation of that EDCM Connectee excluding the value of sole use assets associated with exempt export capacity.

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.

17.2 Where a customer demonstrates with written evidence to the DNO Party (or where the DNO Party has written evidence) that the customer (or its predecessors) made a capitalised O&M payment in respect of a connection to the DNO Party's network, and the period over which the O&M payment was capitalised remains unexpired, then the import fixed charge will be calculated as set out below (and the calculation for the import fixed charge in paragraph 17.1 will not apply).

The sole use assets will be split between those where capitalised O&M has been paid and those where it has not, and the fixed charge will be derived as follows:

p/day = (((DOC rate + NR rate) * SUA MEAVU) + (NR rate * SUA MEAVP)) / (days in Charging Year) * 100

Where:

DOC rate is the direct operating costs contribution rate in per cent;
NR rate is the network rates contribution rate in per cent;
Where SUA MEAVU is the Modern Equivalent Asset Value of Sole Use Assets where capitalised O&M has not been paid (or the period over which it was to be capitalised has expired);

and SUA MEAVP is the Modern Equivalent Asset Value of Sole Use Assets where capitalised O&M has been paid (and the period over which it was to be capitalised has not expired).

17.3 For customers that are classified as exempt pre-2005 EDCM Distributed Generators (DGs), it is deemed for the purposes of paragraph 17.2 that the customer paid capitalised O&M to be capitalised over a period of 25 years from connection.

18. DEMAND SCALING

18.1 Demand scaling is the process by which import charges to EDCM Connectees are set so that the forecast notional recovery from the application of those import charges to EDCM Connectees matches the EDCM demand revenue target.

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

- Calculating adjusted site-specific shared asset values for each Connectee 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 Connectees on the basis of adjusted site-specific assets and sole use assets. [a]

- Allocation of the indirect cost element in the EDCM demand revenue target to individual EDCM Connectees on the basis of their consumption at the time of the DNO Party's peak and 50 per cent of Maximum Import Capacity as a p/kVA/day charge. [b]

- Forecasting the notional recoveries from the application of LRIC charges to EDCM Connectee. [c]

- Allocation of 80 per cent of the difference between the EDCM demand revenue target and the sum of 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.

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

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

- In ascending order, list the network use factors for all EDCM Connectees in all DNO Party 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 EDCM Connectee.

- 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.

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

18.6 The network use factor (NUF) caps and collars for 2011/2012 and each network level were calculated using this methodology and are set out in Table 4 below. The NUF caps and collars using 2015/2016 data for each network level have also been determined, and are set out in Table 4A below.

Table 4 Network use factor caps and collars (2011/2012)

Network levels	Collar	Cap
132kV	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	2.678

Table 4A Network use factor caps and collars (using 2015/16 data)

Network levels	Collar	Cap
132kV	0.192	1.859
132kV/EHV	0.674	1.551
EHV	0.367	2.366
EHV/HV	0.635	1.616
132kV/HV	0.808	1.652

18.7 The caps and collars in Table 4 above were fixed for three years, and were used to calculate charges for the Charging Years 2012/2013 and 2013/2014. The caps and collars are to be re-calculated for the subsequent Charging Years. From Charging Year 2017/2018 onwards the caps and collars are to be calculated using the methodology described in paragraph 18.5 based on the NUFs described in paragraph 18.8. The NUFs themselves are calculated in accordance with paragraphs 29 and 30 below.

18.8 Table 5 below sets out the schedule for the calculation of the NUF caps and collars for each Charging Year.

Table 5 NUF cap and collar calculation timeline

Charging Year	**Caps and collars**
2011/2012 Submission	2011/2012 caps/collars (as per table 4)
2012/2013	2011/2012 caps/collars (as per table 4)
2013/2014	2011/2012 caps/collars (as per table 4)
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	2015/2016 caps/collars (as per table 4A)
2018/2019	2015/2016 caps/collars (as per table 4A)
2019/2020	2015/2016 caps/collars (as per table 4A)
2020/2021	Average of 2015/2016, 2016/2017, 2017/2018 NUFs
2021/2022	Average of 2015/2016, 2016/2017, 2017/2018 NUFs
2022/2023	Average of 2015/2016, 2016/2017, 2017/2018 NUFs
2023/2024	Average of 2017/2018, 2018/2019, 2019/2020, NUFs
2024/2025	Average of 2017/2018, 2018/2019, 2019/2020, NUFs
2025/2026	Average of 2017/2018, 2018/2019, 2019/2020 NUFs

18.9 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 Import Capacity of the EDCM Connectee, and for network levels above on consumption at peak time.

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

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

Where:

NUaL is the adjusted network use factor for that EDCM Connectee 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.

18.10 The total value of the adjusted site-specific shared assets required to serve each EDCM Connectee 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 EDCM Connectee.

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

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

18.11 Total adjusted site-specific shared assets for all EDCM demand is the aggregate value (in £) of all adjusted site-specific shared assets for EDCM Connectees. This is calculated by multiplying TNAa by the Maximum Import Capacity (adjusted, if necessary, for Connectees connected for part of the Charging Year), and then aggregating across all EDCM demand.

18.12 The direct cost and network rates allocations to individual demand Connectees 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.

18.13 A single asset based charging rate for network rates is calculated for all EDCM Connectee. 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 Connectee.

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

18.14 A single asset based charging rate for direct operating costs is calculated for all EDCM Connectees. 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 Connectee.

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

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

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 EDCM Connectee.

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

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

18.16 A p/kVA/day charging rate for indirect costs for each EDCM Connectee is calculated on the basis of historical demand at the time of the DNO Party's peak and 50 per cent of Maximum Import Capacity of that Connectee.

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 EDCM Connectees.

Coincidence factor is calculated as the forecast peak-time consumption in kW divided by Maximum Import Capacity in kVA of that Connectee (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 Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

LDNO factor takes the value 0.5 if the EDCM Connectee is connected to a LDNO's network 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 Connectee.

18.17 The p/kVA/day charging rate for indirect costs is converted into an import capacity based charge for each EDCM Connectee 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 Distribution System-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 Import Capacity in kVA of that Connectee (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 EDCM Connectee is connected to a LDNO's network and 1 otherwise.

18.18 A single asset based residual revenue charging rate is calculated for all EDCM Connectees. 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 - /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 Connectee.

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

SU recovery is the forecast notional recovery from the application of import fixed charges (before any rounding) for sole use assets relating to EDCM Connectees.

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

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

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 EDCM Connectee.

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

18.20 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 Connectee (from annex 3).

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

SU recovery is the forecast notional recovery from the application of import fixed charges (before any rounding) for sole use assets relating to EDCM Connectees.

LRIC recovery is the forecast notional recovery from the application of LRIC charges (before any rounding) to all EDCM Connectees 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 Connectee (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 Connectee is connected for part of the Charging Year) in kVA for that EDCM Connectee.

18.21 The fixed adder in p/kVA/day is converted into an import capacity based charge for each EDCM Connectee as follows:

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

Where:

Fixed adder is the Distribution System-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 Import Capacity in kVA of that Connectee (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)).

19. APPLICATION OF EDCM CHARGES FOR EDCM CONNECTEES

19.1 The tariff application rules for the EDCM are the same as for the CDCM wherever possible. Each component of each tariff is rounded to the nearest value with no more than three decimal places in the case of unit rates expressed in p/kWh, and with no more than two decimal places in the case of fixed and capacity charges expressed in p/day and p/kVA/day respectively.

19.2 The part of EDCM portfolio tariffs (for LDNO networks and Distribution Licence exempt networks) that is based on CDCM tariffs will be billed like CDCM tariffs.

19.3 Final EDCM demand charges will have:

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

19.4 The import fixed charge on sole use assets in p/day is applied to each EDCM Connectee.

19.5 The final EDCM import capacity charge for each EDCM Connectee in p/kVA/day would be calculated as follows:

EDCM import capacity charge (p/kVA/day) = [LRIC 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]

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

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

Adjusted LRIC super-red unit rate in p/kWh = [LRIC 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]))

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

19.9 Final EDCM export charges will have:

1. An export fixed charge on sole use assets (in p/day)

2. An export capacity charge (in p/kVA/day), which might include transmission exit credits to qualifying generators.

3. An export super-red unit rate (in p/kWh)

4. An exceeded export capacity charge (in p/kVA/day)

19.10 The export capacity charge (in p/kVA/day) is applied to the Chargeable Export Capacity of EDCM Connectees.

19.11 The export super-red unit rate (in p/kWh) is applied to active power units exported during the DNO Party’s super-red time band.

20. EXCEEDED CAPACITY CHARGES

20.1 Where a Connectee uses additional capacity over and above the Maximum Import Capacity or Maximum Export Capacity without authorisation, the excess is classed as exceeded capacity.

20.2 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

Export capacity used = 2 * (SQRT(AE^2 + MAX(RI,RE)^2))

Where:

AE = Import consumption in kWh

RI = Reactive import in kVArh

RE = Reactive export in kVArh

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

20.4 For the purposes of calculating exceeded capacity for export charges, any reactive flows during half hours when there is no active power export will not be taken into account.

20.5 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 Party would not be taken into account when calculating import or export capacity used.

20.6 For Connectees other than those that have an agreement with the DNO, the terms of which require them, for the purposes of P2/6 compliance, to export power during supergrid transformer (SGT) outage conditions, the exceeded portion of the export capacity is charged at the same rate as the capacity that is within the Maximum Export Capacity. This is charged for the duration of the month in which the breach occurs.

20.7 For Connectees other than those with DSM agreements, the exceeded portion of the import capacity is charged at the same rate as the capacity that is within the Maximum Import Capacity. This is charged for the duration of the month in which the breach occurs.

20.8 Sites subject to DSM arrangements would normally pay the DSM-adjusted capacity charge for capacity usage up to their Maximum Import Capacities.

20.9 If sites with DSM agreements were to exceed their maximum import 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] + (([LRIC capacity charge p/kVA/day] + ([LRIC super-red rate p/kWh] * [Average kW/kVA adjusted for part year] * [super-red hours] / ([days in Charging Year] – [Days for which not a customer]))) * (1 - ([chargeable capacity]/ [Maximum Import Capacity]))

Where:

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

21. APPLICATION OF EDCM IMPORT CHARGE COMPONENTS

21.1 Table 6 summarises the method of application of import charge components.

Table 6 Application of EDCM import charge components

Tariff component	Unit	Application
Import 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)
Import super-red unit rate	p/kWh	Applied to active power units consumed during the DNO Party's super-red time band.

21.2 Table 7 summarises the method of application of export charge components.

Table 7 Application of EDCM export charge components

Tariff component	Unit	Application
Export fixed charge	p/day	Applied as a fixed charge.
Export capacity charge	p/kVA/day	Applied to the Chargeable Export Capacity.
Exceeded export 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)
Export super-red unit rate	p/kWh	Applied to active power units exported during the DNO Party's super-red time band.

22. CHARGES FOR NEW CONNECTEES

22.1 New Connectees could connect at any time between the publication of EDCM charges for the new Charging Year and the end of that Charging Year.

22.2 If the connection of such Connectees had been anticipated before the publication of charges, the DNO Party would have included forecast data relating to the new Connectee in both the power flow model and the EDCM tariff model. The resulting tariff is applied to the new Connectee, on a pro-rata basis if the price is produced during the Charging Year.

22.3 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 Connectee, failing that, make a reasonable estimate;
- Run the power flow model after including the new Connectee to produce a full set of charges 1 and 2, including for the new Connectee;

- Include the new Connectee's details, including marginal charges from (a) in the EDCM tariff model, to produce a full set of new charges;
- Use the tariff relating to the new Connectee to calculate charges; and
- Charges relating to the current year for existing Connectees would not change as a result.

22.4 If a Connectee were to change their maximum import or export capacity at any time between the publication of EDCM charges 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.

23. DNO TO DNO CHARGES

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

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

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

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

(d) All other interconnections between DNO Parties.

23.2 In all cases of type (a), the benefitting DNO Party will be treated as being equivalent to an EDCM Connectee connected to the other DNO Party's network. The DNO Party providing the benefit will calculate and apply EDCM import charges, except charges for sole use assets. as applicable to the other DNO Party. Export charges or credits will not apply.

23.3 In the case of type (b) interconnections, each DNO Party will treat the other as an EDCM Connectee. Normal EDCM import charges, except charges for sole use assets, will apply. Export charges or credits will not apply.

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

23.5 In every other case, each DNO Party applies import charges to the other as a normal EDCM Connectee, as with type (b) interconnections.

24. LDNO CHARGING

24.1 LDNOs with Distribution Systems that serve Connectees 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 charges.

A LDNO with a Distribution System that qualifies as a CDCM “Designated Property” according to the definition set out in condition 13A.6 of the Distribution Licence is eligible for portfolio discounts calculated using a price control disaggregation model (method M) consistent with the CDCM.

A LDNO with a Distribution System that qualifies as an EDCM “Designated EHV Property” according to the definition set out in condition 13B.6 of the Distribution Licence is are eligible for discounts calculated using an “extended” price control disaggregation model (extended method M).

24.2 A LDNO with a Distribution System that qualifies as an EDCM “Designated EHV Property” could itself have Connectees who would fall under the scope of the EDCM. Since the EDCM is a locational charging method, the host DNO Party would calculate EDCM charges at the DNO Party’s boundary for each EDCM-like Connectee on the LDNO’s Distribution System. No discounts are calculated for such EDCM Connectees as the DNO Party’s charges are based only on the specific site’s equivalent use of the DNO Party’s Distribution System.

25. CALCULATION OF LDNO DISCOUNTS

25.1 The discount percentages are determined in accordance with Schedule 29, which is deemed to form part of this EDCM (as if it were set out herein).

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

25.3 Not used.

25.4 Not used.

25.5 Not used.

25.6 Not used.

25.7 Not used.

25.8 Not used.

25.9 Not used.

25.10 Not used.

25.11 Not used.

25.12 Not used.

25.13 Not used.

25.14 Not used.

25.15 Not used.

25.16 Not used.

25.17 Not used.

25.18 Not used.

25.19 Not used.

26. PORTFOLIO EDCM TARIFFS FOR CONNECTEES IN THE EDCM

26.1 For Connectees on a LDNO's Distribution System that would be covered by the EDCM if they were on the DNO Party's Distribution System, the EDCM is applied to calculate a portfolio EDCM charge/credit for each such Connectee.

26.2 These EDCM portfolio charges would be calculated as if each EDCM Connectee on the LDNO's Distribution System were notionally connected at the boundary between the DNO Party and the LDNO; except for LDNO UMS tariffs, which are charged by reference to the voltage of the Points of Connection that provide the majority of the energised domestic connections for the LDNO in the GSP Group (or, where there is no such majority, on such other reasonable basis as the DNO Party determines). Both EDCM import and export charges will apply.

26.3 For the purposes of calculating the boundary-equivalent portfolio EDCM tariffs, each EDCM Connectee on the LDNO's Distribution System would be assigned the demand Connectee category determined by reference to that LDNO Distribution System's Point of Common Coupling. The demand Connectee category is assigned as per Table 3 in paragraph 15.6.

26.4 Such Connectees would attract charges (credits) in respect of any reinforcements caused (avoided) on the DNO Party's Distribution System only, i.e. any network Branches that are on the LDNO's Distribution System would be attributed a zero LRIC charge/credit.

26.5 The setting of final charges to Embedded Designated EHV Properties including the calculation of charges for assets used on the LDNO's Distribution System will be established by the LDNO.

26.6 All EDCM charges would be calculated using "boundary equivalent" data provided by the LDNO to the host DNO Party 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 Party - LDNO boundary, for each EDCM Connectee, after taking into consideration the diversity and losses within the LDNO's Distribution System. 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.

26.7 The EDCM will include in the charges for Embedded Designated EHV Properties a fixed charge relating to any assets on the DNO Party's Distribution System that are for the sole use of a LDNO Party's Distribution System. The assets on the DNO Party's network that are for the sole use of a LDNO Distribution System are defined as the assets in which only consumption or output associated with Embedded customers on the LDNO Distribution System can directly alter the power flow in the asset, taking into consideration all possible credible running arrangements, i.e. all assets between the asset ownership boundary and the LDNO Distribution System's Point of Common Coupling are considered as sole use assets. These fixed charges would be calculated in the same way as it would be for EDCM Connectees connected directly to the host DNO Party's Distribution System.

26.8 In calculating charges for assets on the DNO Party's Distribution System that are for the sole use of a LDNO's Distribution System, DNO Party's 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 Connectee to the capacity at the LDNO - DNO Party boundary.

26.9 If there are no Embedded Designated EHV Properties on the LDNO's Distribution System, no sole use asset charges would apply.

26.10 Demand scaling would be applied as normal to any EDCM portfolio tariff in respect of an EDCM Connectee. For the purposes of scaling, all EDCM Connectees connected to the LDNO's Distribution System will be treated as notional EDCM Connectees connected to the DNO Party's Distribution System with a Point of Common Coupling at the LDNO Distribution System's Point of Common Coupling.

26.11 For EDCM Connectees connected to the LDNO's Distribution System, the capacity-based charge for the DNO Party's indirect costs and the 20% share of residual revenue that is applied as a fixed adder, would be scaled down by a factor of 50 per cent, however, the scaling down will not apply where the residual revenue is negative.

27. OFFSHORE NETWORKS CHARGING

27.1 The DNO Party will treat offshore networks connected to the DNO Party as if they were EDCM Connectees.

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

27.3 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 Connectee.

27.4 Demand scaling will also be applied.

28. DNO PARTY TO LICENCE EXEMPT SYSTEMDS~~UNLICENSED NETWORKS~~

28.1 Not used. ~~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.~~

28.2 Otherwise, the DNO Party applies the EDCM to calculate an import charge and an export charge based on~~ capacity and~~ power flow data ~~metered~~ at the boundary and agreed capacity 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 Connectee.~~

28.2A The tariffs charged in respect of Licence Exempt Systems~~unlicensed networks~~ using Difference Metering shall be charged to the Supplier at the DNO Party's boundary based on the units imported or exported at the boundary between the network and the Licence Exempt System~~unlicensed network~~. No charges will be applied by the DNO Party to the boundary settlements data received by the DNO Party, or to the settlements data received in respect of the settlements meter within the Licence Exempt System~~unlicensed network~~.

28.2B **The tariffs charged in respect of** Licence Exempt Systems **using Fully Settled metering shall be charged to the Supplier at the DNO Party's boundary**

28.3 Licence Exempt Systems that serve Connectees 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 charges.

28.4 Tariffs for customers connected to Licence Exempt Systems are determined in accordance with paragraph 88a of schedule 16, save that lower voltage elements are excluded as follows:

- where the Licence Exempt System is connected at an EHV/HV substation, the costs associated with the LV customer, LV network, LV substation and HV network levels are excluded;
- where the Licence Exempt System is connected to the EHV network, the costs associated with the LV customer, LV network, LV substation, HV network and EHV/HV levels are excluded;
- where the Licence Exempt System is connected at a 132kV/EHV substation, the costs associated with the LV customer, LV network, LV substation, HV network, EHV/HV and EHV network levels are excluded;
- where the Licence Exempt System is connected to the 132kV network, the costs associated with the LV customer, LV network, LV substation, HV network, EHV/HV, EHV network and 132kV/EHV levels are excluded;
- where the Licence Exempt System is connected direct to a GSP, the costs associated with the LV customer, LV network, LV substation, HV network, EHV/HV, EHV network, 132kV/EHV and 132kV network levels are excluded.

28.3B Capacity charge elements (p/kVA/day) for half-hourly site-specific settled customers connected to Licence Exempt Systems are allocated to the fixed charge (in p/day) by multiplying the capacity charge by the average kVA per customer for an equivalent all-the-way customer, determined from the DNO Party's volume forecast for the equivalent all-the-way half-hourly metered tariff at that voltage as determined under schedule 16.

28.3C Reactive power charge elements (p/kVArh) for half-hourly site-specific settled customers connected to Licence Exempt Systems are allocated to the fixed charge (in p/day) by multiplying the reactive power charge by the average kVArh per customer for an equivalent all-the-way customer, determined from the DNO Party's volume forecast for the equivalent all-the-way half-hourly metered tariff at that voltage as determined under schedule 16, and dividing by the number of days in the charging year.

Commented [RC16]: Need to explain how this is determined.

Commented [RC17]: NK to provide an example to include:

- Summate metering data from conectees to understand when consumption being used
- Power flow analysis to determine tariff
- Allocation to each connectee

29. DERIVATION OF 'NETWORK USE FACTORS'

Step 1:

29.1 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 EDCM demand or CDCM demand at the EHV/HV boundary.

29.2 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)

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

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

30. INCREMENTAL METHOD:

30.1 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.

30.2 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 Connectee 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.

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

Step 2:

30.4 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:

30.5 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:

30.6 Each nodal demand's proportionate usage of a Branch is determined using the equation below:

Alloc (£/year) = ([MW usage] / [Total MW usage]) * (Abs [Max contingency flow] / [Rating]) * AMEAV

If the Branch is "generation-dominated", or (2 * Abs [Base flow load]) ≤ Abs ([Base flow] - [Base flow load]), then use:

Alloc (£/year) = ([MW usage] / [Total MW usage]) * (Abs [Max contingency flow] / [Rating]) * Abs ([Base flow load] / [Base flow]) * AMEAV

Where:

- Alloc   is the allocation of the AMEAV of the asset to a demand user in £/year
- MW   usage is the absolute value of the "MW usage" of the asset attributable to that demand user (expressed in MW)
- Total MW usage is the sum of the absolute values of the "MW usage" of all demand users of that asset (expressed in MW)
- Max contingency flow is the maximum post-contingent flow through the asset in MVA. The maximum post-contingency asset flows may be extracted from the 'locational' analyses.
- Rating is the unadjusted rated capacity of the asset in MVA
- Base flow load is the algebraic sum of power flows through the Branch due to demand only in MW.
- Base flow is the aggregate power flow through the Branch under normal network operation in MW.
- AMEAV is the annualised modern equivalent asset value in £/year of that asset.
- The ratio ([Max contingency flow] / [Rating]) is called the asset utilisation factor and it is capped at 1.

The quantity (Abs [Max contingency flow] / [Rating]) * Abs ([Base flow load] / [Base flow]) is called the load utilisation factor.

3II.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:

3II.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’.

30.9 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.

30.10 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 Party 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.

30.11 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.

Amend Paragraph 4.1 of Schedule 19

4. MPAN REPORT

4.1 On or before the 15th day of each month, the EDNO shall send to the DNO Party a list of the EDNO's MPANs for half-hourly settled Connectees, together with the following information (in separate columns) for each such MPAN (as at the start of that month):

(a) its trading status;

(b) the date from which such trading status has been effective;

(c) its energisation status; and

(d) the date from which such energisation status has been effective;

(e) its Meter Timeswitch Code; and

(f) the date from which such Meter Timeswitch Code has been effective.

4.2. Where there are no half-hourly-settled Connectees, the EDNO shall submit a nil return.