SCHEDULE 16 – COMMON DISTRIBUTION CHARGING METHODOLOGY

Introduction

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).

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 '100' as issued by the Panel on 01 April 2010.

   Comment [AP1]: To be amended for new version of spreadsheet model

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.
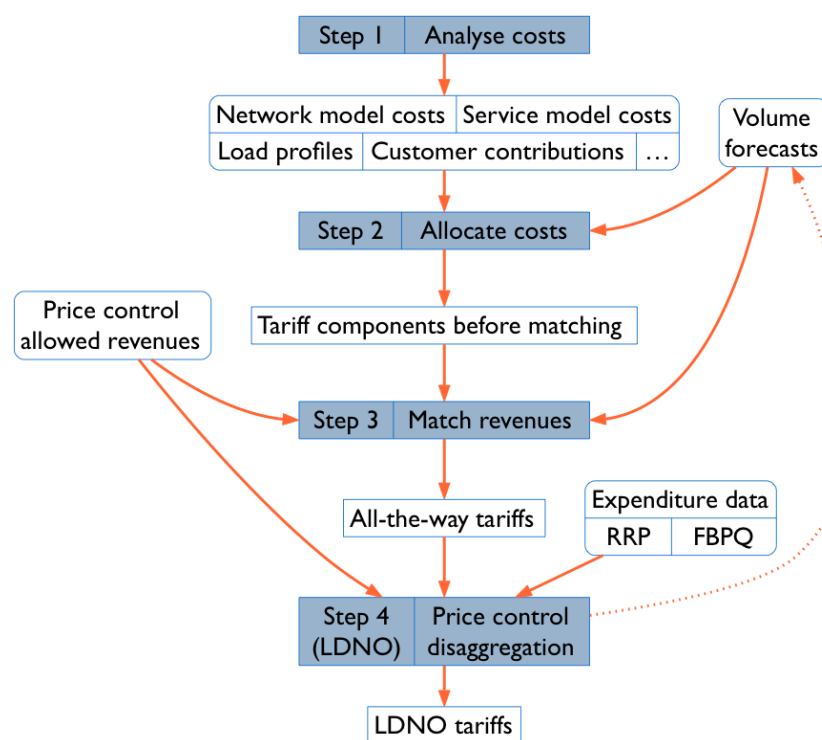
Part 1 — Cost allocation

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

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 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 the tariff components listed in table 1.

Table 1   List of tariff components and restrictions on their application

Tariff component	*Unit*	*Restrictions*
One, two or three unit rates	p/kWh	No more than two unit rates for non half hourly settled demand.
Fixed charge	p/day	Not for unmetered supplies.
Capacity charge	p/kVA/day	Half hourly settled demand tariffs only.
Reactive power charge	p/kVArh	Half hourly settled tariffs only.

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 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. In all cases, 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 and HV network levels.

18. For DNO Parties that do not rely on a separate EHV charging methodology, the network model also determines these costs at the EHV/HV and EHV network levels, and, in England and Wales, at the 132kV/EHV and 132kV network levels.

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 ~~three~~ five distribution time bands, labelled black, red, yellow, amber and green. The red, amber and green timebands will apply to all half hourly settled tariffs with the exception of the unmetered supplies half hourly tariff. The black, yellow and green timebands will apply only 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. ~~Each time band may be divided into any number of sections.~~There will be no constraint on either the number of hours that can be covered by each time band or whether the time band can be split during the day. The red, amber and green times bands will apply throughout the year. The black and yellow time bands can apply to any part of the year, as specified by the DNO.

Load characteristics

~~41.~~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 factors, coincidence factors and proportion of units that fall within each distribution time band for non-half hourly and half hourly unmetered supplies tariffs are calculated based on sample data from pseudo HH meters. The DNO can acquire this data from a third party if they deem this to be appropriate.

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 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

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individually for each of the 3 years and a simple arithmetic average will be calculated to be used in tariff setting.

42.44.   For load factors and coincidence factors in the case of non half hourly settled customer classes, data adjusted for GSP Group correction factor are used.

43.45.   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.

44.46.   Not Used

Settlement data for non half hourly unmetered supplies are not used to determine load characteristics. Instead, the load factor and coincidence factor for this user class are set equal to the figures for pseudo half hourly LV unmetered supplies, if any. If no data are available for pseudo half hourly LV unmetered supplies in the relevant area, data for pseudo half hourly LV unmetered supplies from another area are used as a proxy.

Loss adjustment factors to transmission

45.47.   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

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

47.49.   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 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

48.50.   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.

49.51.   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

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

51.53.   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

52.54.   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.

Step 2: Allocate costs

Categories of costs

53.55.   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.

54.56.   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

55.57.   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	6.9% until the 31 March 2011, and thereafter the

Table 3 **Annuity rate of return and annuity period**

Parameter	*Value*
	"allowed pre- tax weighted average cost of capital" set by the Authority as part of the then most recent review of the charge restriction conditions applying under the DNO Party's Distribution Licence.

Determination of unit costs from network model

56.58.   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.

57.59.   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]

58.60.   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

59.61.   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.

60.62.   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.

61.63.   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]

62.64.   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.

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

64.66.   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

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

66.68.   For demand tariffs and portfolio tariffs related to demand users with a single unit rate (with the exception of the 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]*[coincidence factor]/[load factor]*(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]*[coincidence factor]/[load

factor]/[days in charging year]/24

67.69. These calculations are repeated for each network level.

68.70. In this equation, the user loss factor is the loss adjustment factor to transmission for the network level at which the user is supplied, and the network level loss factor is the loss adjustment factor to transmission for the network level for which costs are being attributed.

69.71. For generation users 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

70.72. For tariffs with several unit rates and non-half hourly unmetered supplies tariffs, the same principle is used but the ratio of the coincidence factor to the load factor is replaced with a coefficient calculated by the following procedure:

a) 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.

b) 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.

c)b)

d) For each network level and each unit rate, replace the ratio of the coincidence factor to the load factor in the above formula with the ratio of coincidence factor (to network level asset peak) to load factor that would be apply given peaking probabilities at that network level if units were uniformly spread within each time band, multiplied by the correction factor.

c)

d) The coefficient calculated for the non-half hourly and half hourly unmetered supplies tariffs will be determined by aggregating these tariffs to produce one value.

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

71.73. 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.

72.74. The standing charge factors for non half hourly settled users are:

a) 100 per cent for the network level at which the end user is supplied.

b) Zero for any further network level.

73.75. The standing charge factors for half hourly settled users at LV Sub and HV Sub are:

a) 100 per cent for the transformation level at which the supply is made to the end user.

b) 100 per cent for circuits at the next voltage level.

c) Zero for any further network level.

74.76. The standing charge factors for other half hourly settled users are:

a) 100 per cent for the voltage level of supply of the end user.

b) 100 per cent for the next transformation level.

c) 20 per cent for circuits at the next voltage level (including 132kV for HV users to the extent that 132kV/HV transformation is used).

d) Zero for any further network level.

75.77. 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]).

76.78. 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]

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

78.80.   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.

79.81.   For half hourly settled demand users, except unmetered users, the unit costs calculated by the formula above are allocated to the capacity charge.

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

81.83.   For domestic users in profile classes 1 and 2, and for small business users in profile classes 3 and 4, 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 small business MPANs. Related MPANs are excluded from this calculation and are not subject to the resulting fixed charge.

82.84.   For non half hourly settled demand users, except unmetered users, 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.

Costs associated with LV customer and HV customer levels

83.85.   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.

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

Costs associated with reactive power flows

85.87.   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.

86.88.   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.

Step 3: Match revenues

87.89.   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.

88.90.   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.

89.91.   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.

90.92.   To allocate any shortfall or surplus, the DNO Party calculates the effect on demand tariffs and on forecast revenues from these tariffs of adding £1/kW/year (relative to system simultaneous maximum load) to costs at the transmission exit level.

91.93.   Using this estimate, the DNO Party determines a single adder figure in £/kW/year such that adding that amount to costs at the transmission exit level would eliminate the shortfall or surplus. The single adder is positive if there is a shortfall and negative if there is a surplus.

92.94.   If this procedure would result in negative value for any tariff component, then the tariff component is set to zero and the single adder figure is modified to the extent necessary to match forecast and target revenue.

93.95.   The final tariffs for demand (before rounding and application of LDNO discounts) are determined on the basis of an allocation with the single adder included in costs. Tariffs for generation do not have any revenue matching element.

Step 4: Price control disaggregation

94.96.   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.

95.97.   For the purposes of price control disaggregation the network is split into five levels: LV services, LV mains, HV/LV, HV and EHV.

96.98.   The determination of discount percentages involves the following steps:

a)   Allocation of price control revenue elements to network levels.

b)   Determination of a percentage allocation of total revenue per unit to network levels.

c)   Determination of the proportion of the LV mains deemed to be used by LV-connected embedded networks.

d)   Allocation of 100% of the LV services to LV-connected embedded networks (the "[LV services allocation]").

e)   Determination of the proportion of the HV network deemed to be provided by HV-connected embedded networks with HV end users.

f)   Calculation of the discount percentage for each combination of boundary network level and end user network level.

g)   Application of discount percentages to determine portfolio tariffs.

Allocation of price control revenue elements to network levels

97.99.   The calculation of percentage allocations of price control revenues to network levels is based on separate percentages by network level for the operating cost, depreciation and return on the regulatory asset value elements of the DNO Party's allowed revenue.

98.100.   In order to determine the allocation to network levels of each element of price control revenue, the DNO Party uses the costs allocation drivers calculated from the following sources:

a)   RRP data on units distributed and operating expenditure broken down by network level.

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

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

99.101.   Data from the RRP are used to distinguish between direct and indirect costs, with direct costs coded by network level. For the purpose of this calculation, capital expenditure is included, net of customer contributions, but negative figures are replaced with zero. This analysis provides direct costs percentage for each network level, based on RRP data. The direct cost percentage for LV mains is denoted "[LV mains direct proportion]" and the direct cost percentage for HV is denoted "[HV direct proportion]".

100.102.   Indirect operating costs are allocated to network levels on the basis of an estimate of modern equivalent asset value by network level. The operating cost percentage for each level is a weighted average of the direct and indirect percentages. Estimated gross modern equivalent asset values used for this purpose are derived from asset counts and gross modern equivalent asset values (replacement costs) for various asset types.

101.103.   Transmission exit charges are not allocated to any of the voltage tiers. These charges are deducted from the allowed revenue (see paragraph 111).

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

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

104.106.   Some of these categories allow HV substation and transformer costs to be identified. These costs (and no other costs) are allocated to the HV/LV network level.

105.107.   Some of the expenditure categories do not separately identify HV substation/transformer costs. For these categories costs are allocated to the HV/LV in the same proportion as for the other categories (where these costs are separately identified).

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

Determination of a percentage allocation of total revenue per unit to network levels

107.109.   The percentage allocation of costs to network levels is determined as a weighted average of the percentage allocation for each of the elements of price control revenue, rescaled by units flowing.

108.110.   The DNO Party determines a breakdown of price control allowed revenue over the period from 2005/2006 to 2009/2010 between operating expenditure, depreciation and return on regulatory asset value.

109.111.   For the purpose of that calculation, allowed revenue is adjusted by deducting:

a) the net amount earned or lost by the DNO Party under price control financial incentive schemes; and

b) Transmission exit charges.

110.112. These allocations of the operating expenditure, depreciation and return elements of allowed revenue are combined using weights from the price control breakdown.

111.113. The weighted average allocations are then rescaled by the estimated number of units flowing through each network level, and normalised so that they sum to 100 per cent. The result of this calculation is a set of percentages for each of the LV services, LW mains, HV/LV, HV and EHV network levels.

LV mains split

112.114. The DNO Party determines the proportion of the LV mains which LV-connected embedded networks are deemed to use by:

a) determining the total length of its LV mains used by LV-connected licensed embedded networks;

b) dividing that total length by the number of end users on LV-connected licensed embedded networks; and

c) dividing the result by the average length of LV mains by LV end user on the DNO Party's own LV network.

113.115. The result of this calculation is denoted "[LV mains split]".

HV split

114.116. The DNO Parties will procure that the Nominated Calculation Agent estimates the typical proportion of the HV network which is provided by the DNO Party in the case of HV loads supplied through an HV-connected LDNO. This estimate will be based on sample data, and the average used will be the same for all DNO Parties.

115.117. The proportion is denoted "[HV split]", and is represented as:

$$HV\ Split = 1 - \frac{Sum\ of\ IDNO\ network\ length/Number\ of\ IDNO\ connections}{Sum\ of\ DNO\ network\ lengths/Number\ of\ DNO\ connections}$$

Calculation of discount percentages

116.118. The discount percentages are determined as follows (where "[LV mains allocation]" is the percentage of total costs that are allocated to the LV mains network level).

117.119. For embedded networks with an LV boundary, the discount is equal to:

[LV: LV discount] = [LV services allocation] + ([LV mains allocation]*(1 − [LV mains split]*[LV mains direct proportion])).

118.120. For embedded networks with an HV boundary, three percentage discount figures are used.

119.121. The percentage discount applicable to tariffs for LV network end users is:

[HV: LV discount] = [LV services allocation] + [LV mains allocation] + [HV/LV allocation] + [HV allocation]*(1 – [HV split]*[HV direct proportion]).

120.122. The percentage discount applicable to tariffs for LV substation end users is:

[HV: LV Sub discount] = ([HV/LV allocation] + [HV allocation]*(1-[HV split]*[HV direct proportion]))/(1-[LV mains allocation] – [LV services allocation]).

121.123. The percentage discount applicable to tariffs for HV end users is:

[HV: HV discount] = [HV allocation]*(1 – [HV split]*[HV direct proportion])/ (1 – [LV services allocation] – [LV mains allocation] - [HV/LV allocation])

Application of discount percentages to determine portfolio tariffs

122.124. 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.

123.125. 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.

Part 2 — Tariff structures and application

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

125.127. This part details the common tariff structure and associated tariff elements for Non-Half Hourly (NHH) and Half-Hourly (HH) metered supplies for demand, generation, unmetered supplies and charges to LDNOs.

Tariff structures for demand customers

NHH Metered Demand

126.128. 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)

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

128.130. 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'.

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

130.132. 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.

HH Metered Demand

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

132.134. Charges will consist of a fixed, unit, capacity and reactive power charge.

135. There will be three unit rate time bands on a time of day (ToD) 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. T, the three ToD time bands will be called 'Red', 'Amber' and 'Green' to represent three differing cost signals. There will be no constraint on either the number of hours that can be covered by each time band or whether the time band can be split during the day. A time band can be applied to only cover certain weekdays i.e. Monday to Friday. The times should be applied consistently through the year i.e. ToD rather than seasonal time of day (SToD).

135A. 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.

133.136.   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; and

   e) Reactive power charge p/kVArh.

134.137.   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.

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

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

137.140.   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.

Demand Tariff Structures

138.141.   The following tables and notes show the structure for demand tariffs.

Table 4: Non-half-hourly metered demand tariffs				
Point of Connection	**Profile Class**	**Unit Rate Time Bands**	**Other Charges**	**Tariff Name**

Table 4: Non-half-hourly metered demand tariffs				
Point of Connection	**Profile Class**	**Unit Rate Time Bands**	**Other Charges**	**Tariff Name**
LV	1	One	Fixed	Domestic Unrestricted
LV	2	Two	Fixed	Domestic Two Rate
LV	2	One	None	Domestic Off-Peak (related MPAN)
LV	3	One	Fixed	Small Non-Domestic Unrestricted
LV	4	Two	Fixed	Small Non-Domestic Two Rate
LV	4	One	None	Small Non-Domestic Off-Peak (related MPAN)
LV	5 to 8	Two	Fixed	LV Medium Non-Domestic
LVS	5 to 8	Two	Fixed	LV Sub Non-Domestic
HV	5 to 8	Two	Fixed	HV Medium Non-Domestic *The proposal is that this tariff will be closed to new customers and all new HV connections will be required to be half-hourly metered
LV	8	One	None	NHH UMS (Category A)
LV	1	One	None	NHH UMS (Category B)
LV	1	One	None	NHH UMS (Category C)
LV	1 & 8	One	None	NHH UMS (Category DUnmetered supplies)

Table 5: Half-hourly metered demand tariffs			
Point Of Connection	**Unit Rate Time Bands**	**Other Charges**	**Tariff Name**
LV	Three	Fixed, Capacity and Reactive Power	LV HH metered
LVS	Three		LV Sub HH metered
HV	Three		HV HH metered
HVS	Three		HV Sub HH metered
LV	Three	None	LV UMS (Pseudo HH Metered)

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 used for the customer's settlement metering is located at the substation.

Note 4: HV Sub applies to customers connected to the DNO Party's network at a voltage of at least 1 kV and less than 22 kV at a substation with a primary voltage (the highest operating voltage present at the substation) of at least 22 kV and less than 66 kV, where the current transformer used for the customer's settlement metering or for metering used in the calculation of the customer's Use of System Charges or credits is located at the substation.

Note 5: Notes 3 and 4 above for LV and HV substation tariffs will be applied for new customers from 1 April 2010. Where a customer is already registered on either an LV or HV substation 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 Metered Generation

139.142. Use of System Charges for NHH Low Voltage (LV and LVS) generation tariffs will also 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.

140.143. Structure of NHH generation charges:

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

b) Unit rate charge p/kWh.

HH Metered Generation

141.144. Use of System Charges for HH Low Voltage (LV) and High Voltage (HV) generation tariffs will also 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

142.145. Structure of NHH generation charges:

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

b) Unit rate charge p/kWh; and

c) Reactive power charge p/kVArh.

143.146. The following tables and notes show the structure for generation tariffs.

Table 6: Non-half-hourly metered generation tariffs				
Point of connection	**Profile class**	**Unit Rate Time Bands**	**Other Charges**	**Tariff Name**
LV	8	One	Fixed	LV Generation NHH
LVS				LV Sub Generation NHH

Table 7: Half-hourly metered generation tariffs			
Point Of Connection	**Unit Rate Time bands**	**Other Charges**	**Tariff Name**
LV	One	Fixed and Reactive Power	LV Generation Intermittent
LVS			LV Sub Generation Intermittent
LV	Three		LV Generation Non-Intermittent
LVS			LV Sub Generation Non-Intermittent
HV	One		HV Generation Intermittent
HVS			HV Sub Generation Intermittent
HV	Three		HV Generation Non-Intermittent
HVS			HV Sub Generation Non-Intermittent

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: HV Sub Generation applies to customers connected to the DNO Party's network at a voltage of at least 1 kV and less than 22 kV at a substation with a primary voltage (the highest operating voltage present at the substation) of at least 22 kV and less than 66 kV, where the current transformer used for the customer's settlement metering or for metering used in the calculation of the customer's Use of System Charges or credits is located at the substation.

Note 6: Notes 4 and 5 above for LV and HV generation substation tariffs will be applied for new customers from 1 April 2010.

Tariff structures for LDNOs

144.147.   The tariff structure for LDNOs will mirror the structure of the all-the-way-tariff, and is dependant on the voltage of connection either LV or HV. The same tariff elements will apply.

Table 8: LDNO LV connection				
Point of Connection	Profile Class	Unit Rate Time Bands	Other Charges	Tariff Name
LV	1	One	Fixed	Domestic Unrestricted

Table 8: LDNO LV connection				
Point of Connection	Profile Class	Unit Rate Time Bands	Other Charges	Tariff Name
LV	2	Two	Fixed	Domestic Two Rate
LV	2	One	None	Domestic Off-Peak (related MPAN)
LV	3	One	Fixed	Small Non-Domestic Unrestricted
LV	4	Two	Fixed	Small Non-Domestic Two Rate
LV	4	One	None	Small Non-Domestic Off-Peak (related MPAN)
LV	5 to 8	Two	Fixed	LV Medium Non-Domestic
LV	1 & 8	One	Unit Rate	NHH UMS (Unmetered supplies)
LV	N/A	Three	Fixed, Capacity and Reactive Power	LV HH Metered
LV	N/A	Three	None	LV UMS (Pseudo HH Metered)
LV	8	One	Fixed	LV Generation NHH
LV	N/A	One	Fixed and Reactive Power	LV Generation Intermittent
LV	N/A	Three	Fixed and Reactive Power	LV Generation Non-Intermittent

Table 9: LDNO HV connection				
Point of Connection	Profile Class	Unit Rate Time Bands	Other Charges	Tariff Name
HV	1	One	Fixed	Domestic Unrestricted
HV	2	Two	Fixed	Domestic Two Rate
HV	2	One	None	Domestic Off-Peak (related MPAN)
HV	3	One	Fixed	Small Non-Domestic Unrestricted
HV	4	Two	Fixed	Small Non-Domestic Two Rate
HV	4	One	None	Small Non-Domestic Off-Peak (related MPAN)
HV	5 to 8	Two	Fixed	LV Medium Non-Domestic

Table 9: LDNO HV connection				
Point of Connection	Profile Class	Unit Rate Time Bands	Other Charges	Tariff Name
HV	1 & 8	One	None	NHH UMS (Unmetered supplies)
HV	N/A	Three	Fixed, Capacity and Reactive Power	LV HH Metered
HV	N/A	Three	None	LV UMS (Pseudo HH Metered)
HV	N/A	Three	Fixed, Capacity and Reactive Power	LV Sub HH Metered
HV	N/A	Three	Fixed, Capacity and Reactive Power	HV HH Metered
HV	8	One	Fixed and Reactive Power	LV Generation NHH
HV	N/A	One	Fixed and Reactive Power	LV Generation Intermittent
HV	N/A	Three	Fixed and Reactive Power	LV Generation Non-Intermittent
HV	N/A	One	Fixed and Reactive Power	LV Sub Generation Intermittent
HV	N/A	Three	Fixed and Reactive Power	LV Sub Generation Non-Intermittent
HV	N/A	One	Fixed and Reactive Power	HV Generation Intermittent
HV	N/A	Three	Fixed and Reactive Power	HV Generation Non-Intermittent

Capacity charges

Maximum Import Capacity

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

146.149. 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.

147.150.   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.

148.151.   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

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

Exceeded Capacity

150.153.   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 same p/kVA/day rate, based on the difference between the MIC and the actual capacity. This will be charged for the duration of the month in which the breach occurs.

Minimum Capacity Levels

151.154.   There is no minimum capacity threshold.

Capacity Value Calculations – Import

152.155.   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 kWh
RI = Reactive import in kVArh
RE = Reactive export in kVArh
Import Demand = kVA

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

154.157.   The chargeable capacity is, for each billing period, the highest of the Maximum Import Capacity or the actual capacity, calculated as above, with the same charge rate applying throughout the year.

155.158. Only kVArh Import and kVArh Export values occurring at times of kWh Import are used.

Capacity Value Calculations – Export

156.159. The actual capacity utilised will be calculated by the following formula:

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

Where:
AE = Export production in kWh
RI = Reactive import in kVArh
RE = Reactive export in kVArh
Export Demand = kVA

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

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

159.162. Only kVArh Import and kVArh Export values occurring at times of kWh Export are used.

Reactive power charges

160.163. 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.

161.164. The chargeable reactive power units will be calculated by the following formulae.

Chargeable Reactive Power Unit Calculations - Import

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

Where:
AI = Import consumption in kWh
RI = Reactive Import in kVArh
RE = Reactive export in kVArh

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

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

164.167. Only kVArh Import and kVArh Export values occurring at kWh Import are used.

165.168. The square root calculation will be to two decimal places.

Chargeable Reactive Power Unit Calculations - Export

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

Where:
AE = Export production in kWh
RI = Reactive import in kVArh
RE = Reactive export in kVArh

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

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

168.171. Only kVArh Import and kVArh Export values occurring at kWh Export are used.

169.172. The square root calculation will be to two decimal places.

Charging decimal places

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

Part 3 — Network Unavailability Rebate Payments

~~171.~~174.   A compensation payment may be payable to customers for network outages under two schemes.

~~172.~~175.   The majority of customers are compensated under the Guaranteed Standards arrangements set out in The Electricity (Standards of Performance) Regulations 2010.

~~173.~~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.

~~174.~~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 begenerated (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).

175.178. 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).