dcp 287 draft legal text

(baselined against dcusa version 10.3) + (DCP 311)

SCHEDULE 17

# Application of FCP charge 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.

## 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.

# 6B. Generation credits

## Generation credits are determined as the sum of the individual credits calculated in paragraphs 6.4, 6.5 and 6.6 as follows:

[p/kWh super-red export rate] = ARCC + OEACC + ATECC

Where:

ARCC = Avoided Reinforcement Cost Credit as determined in 6.4

OEACC = Other Expenditure Avoided Cost Credit as determined in 6.5

ATECC = Avoided Transmission Exit Charge Credit as determined in 6.6

## 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:

ARCC = -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.

## An additional credit is applied to embedded generation reflecting Avoided Other Expenditure for the DNO, which is calculated as follows:

## Calculating the lifetime net present value of charge 1, i.e. convert £/kVA/year to £/kVA using the DNOs cost of capital and the asset life. Apply contribution rates as for demand in respect of direct costs, indirect costs and network rates and then convert to p/kwh.

## OEACC = -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]) \* (DOCR + 0.6 \* INCR + NRCR) / [Annuity Rate] / [number of hours in the super-red time band]

## Where:

Annuity Rate is the capital costs that are not covered by customer contributions which are converted to annual costs using a level annuity with the annuity period and rate of return set out in table 3 of Schedule 16.

DOCR = Direct operating costs contribution rate (per cent) as calculated in 16.4

INCR = Indirect costs contribution rate (per cent) as calculated in 16.5

NRCR = Network rates contribution rate (per cent) as calculated in 16.3

## Transmission exit charges are applied to export as a credit. The credit is expressed as a negative charge rate in p/kWh and is calculated as follows:

ATECC = -100 \* [Generation Losses Factor] \* [Proportion eligible for charge 1 credits] \* NGET charge / (CDCM system maximum load + total EDCM peak time consumption) \* ([Chargeable export capacity] / [Maximum export capacity]) / [number of hours in the super-red time band]

Generation Losses Factor is an uplift factor to reflect avoided losses between the GSP and the Connectee.

NGET 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 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.

# Transmission connection (exit) charges for demand

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

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

Transmission exit charging rate p/kW/day = 100 / DC \* NGET charge / (CDCM system maximum load + total EDCM peak time consumption)

Where:

DC is the number of days in the Charging Year.

NGET charge is the 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 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]

# Transmission connection (exit) credits for generators

## In addition to paragraph 6.6, a capacity-based credit related to transmission exit is applied to generation tariffs.

## Transmission exit credits are also 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.

## 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.

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

SCHEDULE 18

# Application of LRIC charge 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.

## 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.

## 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.

## 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.

# 6B. Generation credits

## Generation credits are determined as the sum of the individual credits calculated in paragraphs 6.6, 6.7 and 6.8 as follows:

[p/kWh super-red export rate] = ARCC + OEACC + ATECC

Where:

ARCC = Avoided Reinforcement Cost Credit as determined in 6.6

OEACC = Other Expenditure Avoided Cost Credit as determined in 6.7

ATECC = Avoided Transmission Exit Charge Credit as determined in 6.8

## 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:

ARCC = -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.

## An additional credit is applied to embedded generation reflecting Avoided Other Expenditure for the DNO, which is calculated as follows:

Calculating the lifetime net present value of charge 1, i.e. convert £/kVA/year to £/kVA using the DNOs cost of capital and the asset life. Apply contribution rates as for demand in respect of direct costs, indirect costs and network rates and then convert to p/kwh.

OEACC = - 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]) \* (DOCR + 0.6 \* INCR + NRCR) / [Annuity Rate] / [number of hours in the super-red time band]

Where:

Annuity Rate is the capital costs that are not covered by customer contributions which are converted to annual costs using a level annuity with the annuity period and rate of return set out in table 3 of Schedule 16.

DOCR = Direct operating costs contribution rate (per cent) as calculated in 16.4

INCR = Indirect costs contribution rate (per cent) as calculated in 16.5

NRCR = Network rates contribution rate (per cent) as calculated in 16.3

## Transmission exit charges are applied to export as a credit. The credit is expressed as a negative charge rate in p/kWh and is calculated as follows:

ATECC = -100 \* [Generation Losses Factor] \* [Proportion eligible for charge 1 credits] \* NGET charge / (CDCM system maximum load + total EDCM peak time consumption) \* ([Chargeable export capacity] / [Maximum export capacity]) / [number of hours in the super-red time band]

Generation Losses Factor is an uplift factor to reflect avoided losses between the GSP and the Connectee.

NGET 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 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.

# Transmission connection (exit) charges for demand

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

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

Transmission exit charging rate p/kW/day = 100 / DC \* NGET charge / (CDCM system maximum load + total EDCM peak time consumption)

Where:

DC is the number of days in the Charging Year.

NGET charge is the 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]

# Transmission connection (exit) credits for generators

## In addition to paragraph 6.8, a capacity-based credit related to transmission exit is applied to generation tariffs.

## Transmission exit credits are also 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.

## 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.

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



# POTENTIALLY RELEVANT TEXT FOR ANNUITY RATES/FACTORS

SCHEDULE 16

Annuitisation of network model asset values

1. 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. |

SCHEDULE 17 - Annex 2 - Derivation of FCP charging formulae

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

 (5)

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

 (6)

where:

|  |  |
| --- | --- |
| *i* | is the 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* | is the total cost (£) of asset *j* reinforcement in the considered Network Group; |
| *l* | is index of the total load level at which reinforcement of asset *j* is required; |
| *Cl* | is total demand (kVA) of the Network Group in the year *Yl* in which reinforcement of asset *j* is required; |
| *D* | is initial total demand (kVA) in the Network Group; |
| *gl* | is demand growth rate calculated from  where *Yl* is the number of years into the future when reinforcement of asset *j* is required; |
| *T* | is the 10 year period over which the reinforcement cost is recovered. |

SCHEDULE 18 - Annex 1 – Implementation Guide

*AnnuityRate* is the annuity rate used in the calculation of Branch incremental costs, as described in Attachment 1 below; and

**SCHEDULE 18 - Attachment 1 - Calculation of Branch Incremental Cost**

1. Branch incremental cost is calculated using the outputs of power flow analysis discussed in the Outputs from Power Flow Analysis section and the following formulae for both Maximum and Minimum Demand Scenario:

is the modern equivalent asset value (MEAV) of reinforcing the particular asset, bearing in mind the requirements of similar historic projects[[1]](#footnote-1). This cost is the same under both base and incremental conditions and it should be annualised using the following annuity rate:

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.

is the period over which costs are annualised. This period is set to 40 years and represents the typical life of an asset.

1. Distributors 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. [↑](#footnote-ref-1)