CMP343 Original Legal Text

Drafting related to not yet approved CUSC modifications (CMP317, CMP327) are shown in blue text in this legal text.

All CMP343 text additions/text to be removed are shown in red text

CUSC - SECTION 14

CHARGING METHODOLOGIES

CONTENTS

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.1 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Relevant Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.2 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.3 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.4 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

14.14.5 In April 2004 The Company introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales charging methodology. The DCLF model has been extended to incorporate Scottish network data with existing England and Wales network data to form the GB network in the model. In April 2005, the GB charging methodology implemented ~~the following~~ certain proposals which have been further expanded so that the model now includes the following:

i.) The application of multi-voltage circuit expansion factors with a forward-looking Expansion Constant that does not include substation costs in its derivation.

ii.) The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.

iii.) The application of a de-minimus level demand charge of £0/kW for Half Hourly and £0/kWh for Non~~-~~-Half Hourly metered demand and £0/KWh for

Unmetered Supplies and £0/site/day for **Transmission Demand Residual Tariffs**, to avoid the ~~introduction~~ application of negative demand ~~tariffs~~charges.

iv.) The application of 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.

v.) The Company will set tariffs in a manner so that the locational varying element, as established by the DCLF ICRP model and, where appropriate, local substation and local circuit charges, are levied on all Generator and Demand Users. Any remaining Transmission Owner revenues will be recovered from demand only in a non-locational manner through the **Transmission Demand Residual Tariffs** ~~residual charge.~~

vi.) For the purpose of compliance with the Limiting Regulation in the context of setting limits on the annual charges paid by generation The Company will exclude Charges for Physical Assets Required for Connection when calculating the total amount to be recovered from Generators (GCharge (Forecast)).

… as per CMP317/327 decision

~~vii.) The application of a Transmission Network Use of System Revenue split between generation and demand where the proportion of the total revenue paid by generation, for the purposes of tariff setting for a charging year n, is x times the total revenue, where x is:~~

~~1. Whilst European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit on annual average transmission charge payable by generation) is in effect (a "Limiting Regulation") then:~~

$$x_n = \frac{(Cap_{EC} * (1 - y)) * GO}{MAR * ER}$$

~~Where;~~

~~Cap_{EC} = Upper limit of the range specified a Limiting Regulation~~

~~y = Error margin built in to adjust Cap_{EC} to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

~~GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n~~

~~MAR = Forecast TO Maximum Allowed Revenue (£) for charging year n~~

~~ER = OBR Spring Forecast €/£ Exchange Rate in charging year n-1~~

~~2. Where there is no Limiting Regulation, then x for charging year n is set as the value of x used in the last charging year for which there was a Limiting Regulation.~~

~~viii.)~~vii.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

~~ix.)~~viii.) The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

14.14.6 The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.7 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year. The Security Standard uses a Demand Security Criterion and an Economy Criterion to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

14.14.8 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.9 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.10 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.11 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

14.14.12 Condition C13 of the Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.13 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery from demand only. ~~The combination of both these elements forms the TNUoS tariff.~~

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components ~~and the residual element~~; and the local tariff represents the combination of the two local locational tariff components.

Finally, an Adjustment Tariff component may also be charged to Generators as per paragraph 14.14.5.

14.15.3 The process for calculating the TNUoS tariff is described below.

The Residual Tariff

14.15.134 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges (TRR_t) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where
TRR_t = TNUoS Revenue Recovery target for year t

R_t = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

PVC_t = Forecast Revenue from Pre-Vesting connection charges for year t

SG_{t-1} = The proportion of the under/over recovery included within R_t which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.135 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.136 As a result of the factors above, in order to ensure adequate recovery of total Transmission Owner revenue, a ~~constant~~ set of non-locational **Transmission Demand Residual Tariffs** ~~**Residual Tariff** for demand~~ are~~is~~ calculated, which include~~s~~ infrastructure substation asset costs. These~~is~~ tariffs ~~is~~ are ~~added~~ billed alongside ~~to~~ the initial transport tariffs for demand only so that the total revenue recovery is achieved. The total amount of revenue to be recovered through **Transmission Demand Residual Tariffs** is defined as the **Transmission Demand Residual**.

~~14.15.137 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.~~

$$TDR\cancel{RT_D} = TRR - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE} - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_{GG} - AdjRevenue$$

Where

TDR = **Transmission Demand Residual**

AdjRevenue = Adjustment Revenue as per paragraph 14.14.5

$$\cancel{RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}}$$

$$\cancel{RT = \frac{TRR - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE} - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_{GG} - AdjRevenue}{\sum_{Di=1}^{14} D_{Di}}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

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~~Where~~
~~RT = Residual Tariff (£/MW~~
~~p = Proportion of revenue to be recovered from demand~~

Creation of Charging Bands for use in Transmission Demand Residual Tariff Setting

14.15.137

To produce the **Transmission Demand Residual Tariffs** a set of **Charging Bands** are to be created for each of the **Residual Charging Groups** using the following methodology.

(a) For domestic **Final Demand Sites** whether connected to the **Distribution** system or **Transmission** system there will be one **Charging Band** and;

(b) For non-domestic **Final Demand Sites** connected to the **Distribution** network there will be four **Charging Bands** for each of the **Residual Charging Groups** according to the methodology introduced to Schedule 32 of the **DCUSA** via DCUSA modification DCP358 and entitled 'RESIDUAL CHARGING BANDS' with boundaries set at the 40th, 70th and 85th percentiles and;

(c) For **Final Demand Sites** directly connected to the **Transmission** network there will be one national **Charging Band** and;

(d) For **Unmetered Supplies** there will be one national **Charging Band.**

Domestic **Final Demand Sites**	
LV No Mic	Band 1 (≤40th percentile)
LV No Mic	Band 2 (>40th percentile – 70th percentile)
LV No Mic	Band 3 (>70th percentile – 85th percentile)
LV No Mic	Band 4 (>85th percentile)
LV MIC	Band 1 (≤40th percentile)
LV MIC	Band 2 (>40th percentile – 70th percentile)
LV MIC	Band 3 (>70th percentile – 85th percentile)
LV MIC	Band 4 (>85th percentile)
HV	Band 1 (≤40th percentile)
HV	Band 2 (>40th percentile – 70th percentile)
HV	Band 3 (>70th percentile – 85th percentile)
HV	Band 4 (>85th percentile)
EHV	Band 1 (≤40th percentile)
EHV	Band 2 (>40th percentile – 70th percentile)
EHV	Band 3 (>70th percentile – 85th percentile)
EHV	Band 4 (>85th percentile)
Directly Connected Users Final Demand Sites	
Unmetered Supplies	

14.15.138
These **Charging Bands** will be reviewed periodically and be implemented effective from the beginning of each **Onshore Transmission Owner** price control period.

Transmission Demand Residual Tariff Setting

14.15.139
The **Transmission Demand Residual Tariffs** are derived from the **Transmission Demand Residual** value calculated in 14.15.136 and the total annual consumption of all **Final Demand Sites** and **Unmetered Supplies**.

14.15.140
To determine the proportion of the **Transmission Demand Residual** to be recovered from each **Charging Band**:

(a) Where there are **Final Demand Sites** in a **Charging Band** the total annual consumption from **Final Demand Sites** in the **Charging Band** in question is divided by the total annual consumption from all **Final Demand Sites** and **Unmetered Supplies** creating a percentage value.

(b) Where there are **Unmetered Supplies** in a **Charging Band** the total annual consumption from **Unmetered Supplies** in the **Charging Band** in question is divided by the total annual consumption from all **Final Demand Sites** and **Unmetered Supplies** creating a percentage value.

This percentage is multiplied by the **Transmission Demand Residual** to give the total value to be recovered from the **Charging Band**.

14.15.141
To set **the Transmission Demand Residual Tariff** for each **Charging Band:**

(a) For each **Charging Band** in which there are **Final Demand Sites** the total value to be recovered from the **Charging Band** as per 14.15.140 is divided by the number of **Final Demand Sites** in the **Charging Band** to create a £/site annual charge. This charge is further divided by the number of days in the charging year for which this tariff applies to produce the **Transmission Demand Residual Tariff** for the **Charging Band** (£/site/day).

(b) For each **Charging Band** in which there are **Unmetered Supplies** the total value to be recovered from the **Charging Band** as per 14.15.140 is divided by the total annual consumption from **Unmetered Supplies** in the **Charging Band** in question to create a p/kWh charge. This tariff is also defined as the **UMS Tariff**.

14.15.142 - 14.15.151 - used for new CMP335/6 text

Final £/kW Tariff

15 The effective Transmission Network Use of System tariff (TNUoS) for generation ~~and gross demand~~ can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds and ~~the non-locational residual tariff (for demand) or~~ Adjustment Tariff and ~~and~~ the local tariff (for generation):

$$\cancel{ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}}$$

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + IFF_{GiYRS} + AdjTariff_i}{1000} + LT_{Gi}$$

and

The effective Transmission Network Use of System tariff (TNUoS) for the HH Demand Locational can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds for half-hourly metered demand:

$$\cancel{ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR}}{1000}$$

Where

ET_{Gi}= Effective Generation TNUoS Tariff expressed in £/kW (ET_{Gi} would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances ITT_{GiPS}, ITT_{GiYRNS} and ITT_{GiYRS} will be applied using Power Station specific data)

ET_{Di}= Effective ~~Gross~~ HH Demand Locational TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

ET_{EEi}= Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges ET_{Gi} will be published as ITT_{GiPS}; ITT_{GiYRNS}, ITT_{GiYRS}, ~~RT_G and~~ LT_{Gi} and AdjTariff (if required)

16 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

17 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left(ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{Di} = \frac{12 \times \left(ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$ and $$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The ET_{Gi} element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station G_{Gi}, aggregated to ensure overall correct revenue recovery.

18 If the final ~~gross~~ HH ~~D~~demand Locational TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant ~~non-recovered~~ revenue to be refunded to **Final Demand** smeared over the remaining demand zones via the **Transmission Demand Residual**:

If $FT_{Di} < 0$, then i = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
RFT_{Di} = Revised Final Tariff (£/kW)

19 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

20 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

21 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the

marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

22 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

23 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

24 The factors which will affect the level of TNUoS charges from year to year include but are not limited to-;

- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the Year Round Not Shared (YRNS) Flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- Changes in the pattern of embedded exports
- the £/ € exchange rate and expected Generator Output
- Number of **Final Demand Sites** per **Charging Band**
- Volume (in kWh) apportioned to each **Charging Band**

25 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

Stability & Predictability of TNUoS tariffs

26 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW HH Locational ~~Gross~~ Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group a NHH Demand Locational Tariff is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

£/kW Tariff = The £/kW Effective ~~Gross~~ HH Demand Locational Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

$NHHD_F$ = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

FL_G = Forecast Liability incurred for the GSP Group concerned.

$NHHC_G$ = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff (ET_{Gi}) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

FT	=	Final annual TNUoS Tariff expressed in £/kW
Gi	=	Generation zone
STTEC Period	=	A period applied for in days as defined in the CUSC

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where FT is the final annual TNUoS tariff expressed in £/kW;
G_i is the generation TNUoS zone; and
P is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

14.17 Demand Charges

Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for ~~gross~~ demand locational, **Transmission Demand Residual**, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

Basis of ~~Gross Demand~~ Demand Locational Charges

14.17.3 ~~Gross~~ Demand Locational charges are based on a de minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

14.17.4 Chargeable ~~Gross~~ Demand Locational Capacity is the value of Half Hourly metered Triad ~~gross~~ demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of ~~gross~~ demand locational tariffs within a charging year, the Chargeable ~~Gross~~ Demand Locational Capacity is multiplied by the relevant ~~gross~~ demand locational tariff, for the calculation of ~~gross~~ demand locational charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges.

14.17.7 If multiple sets of ~~gross~~ demand locational tariffs are applicable within a single charging year, ~~gross~~ demand locational charges will be calculated by multiplying the Chargeable ~~Gross~~ Demand Locational Capacity by the relevant tariffs pro-rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Dema} \quad Chargeable\ \cancel{Gross}\ Demand\ Locational\ Capacity \quad \times \left(\frac{(a\times Tariff\ 1)+(b\times Tariff\ 2)}{12}\right)$$

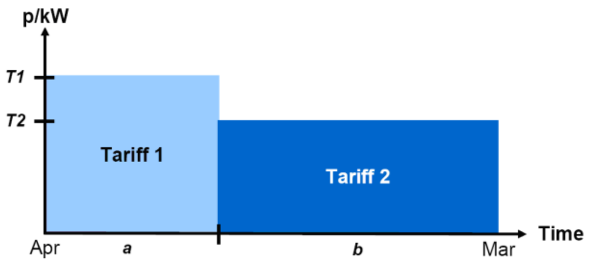
where:

Tariff 1 = Original ta

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.



14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

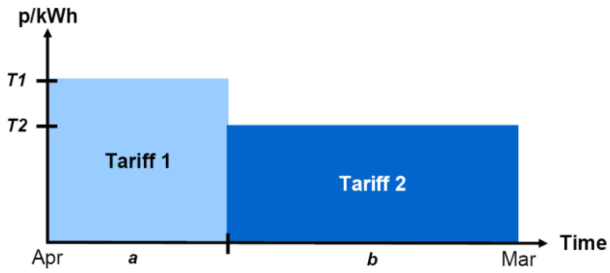
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.



Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demai} \quad \begin{matrix} Chargeable\ Embedded \\ Export\ Capacity \end{matrix} \times \left(\frac{(a \times Tariff\ 1)+(b \times Tariff\ 2)}{12}\right)$$

where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.

Supplier BM Unit

14.17.13 A Supplier BM Unit charges will be the sum of its energy, ~~gross~~ demand locational, **Transmission Demand Residual** and embedded export liabilities where:

- The Chargeable ~~Gross~~ Demand Locational Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff), *and*

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff), *and*~~.~~

- The **Transmission Demand Residual** charge for **Final Demand Sites** will be the sum of the number of sites per **Charging Band** as served by that **Supplier BM Unit** multiplied by the number of days the sites were served by that **Supplier BM Unit** and multiplied by the applicable **Transmission Demand Residual Tariff** £/site/day as determined in 14.15.141, *and*

- The **Transmission Demand Residual** charge for **Unmetered Supplies** will be the sum of the forecast monthly volume of **Unmetered Supplies** per **Charging Band** as served by that **Supplier BM Unit** multiplied by the applicable **UMS Tariff** (p/kWh) as determined in 14.15.141.

Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement

14.17.14 The Chargeable Demand Locational Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the net import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable ~~Gross~~ Demand Locational Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

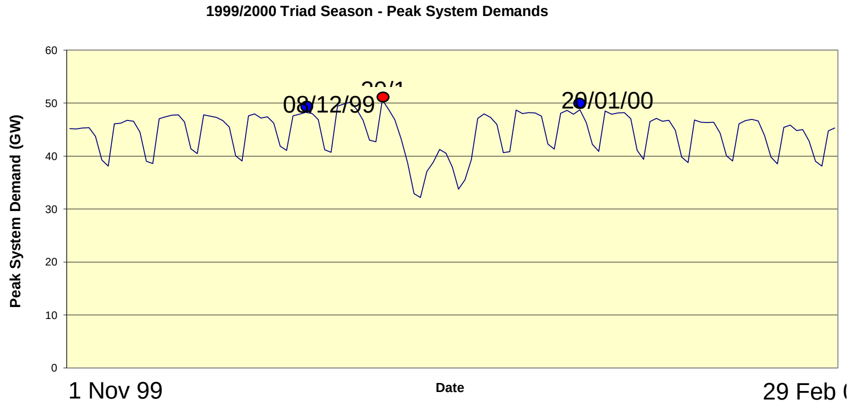
- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to ~~all GB gross demand tariffs~~the **Transmission Demand Residual** ~~charges~~.

The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.



Half-hourly metered ~~D~~demand Locational charges

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.
If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

Monthly Charges

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and
- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and

- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable demand forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User’s Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

Initial Reconciliation Part 2 – Non-half-hourly metered demand

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

Final Reconciliation of demand charges

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

Reconciliation of manifest errors

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.3333 will be in accordance with Sections 14.17.244 to 14.17.3030. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or
b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

Implementation of P272

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies

14.17.35.3 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position

14.17.35.4 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.5 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/ Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.6 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

HH Elective Metering from 1st April 2017. The following section describes how meters migrating to, or already within, Measurement Classes E,F and G will be charged in terms of TNUoS after 31st March 2017.

14.17.29.8 A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation for Non-Half Hourly (NHH) meters migrating to Measurement Classes E, F & G for the charging year which begins after 31 March 2017.

14.17.29.9 Notwithstanding 14.17.9, for each Charging Year which begins after 31 March 2017 demand associated with Measurement Classes F and G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year up until the Charging Year which begins after 31st March 2023. Demand associated with Measurement Class E will continue to be treated as Chargeable Demand Capacity (HH).

14.17.29.10 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from ELEXON i.e. Suppliers need not Supply any additional information.

14.17.29.11 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.16 and 14.17.17 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect the basis on which demand will be charged for TNUoS i.e. volumes associated with those Metering Systems that have transferred to Measurement Class F & G in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity.

Further Information

14.17.35 14**.**25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded consumption and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.36 **The Statement of Use of System Charges** contains the £/kW zonal ~~gross~~ demand locational tariffs, the £/kW zonal embedded export tariffs, ~~and~~ the p/kWh energy consumption tariffs, and the **Transmission Demand Residual tariffs** for the current ~~Financial~~ charging y~~Y~~ear.

14.17.37 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

14.19 Data Requirements

Data Required for Charge Setting

14.19.1 Users who are Generators or Interconnector Asset Owners provide to The Company a forecast for the following Financial Year of the highest Transmission Entry Capacity (TEC) applicable to each Power Station or Interconnector for that Financial Year. For Financial Year 2008/9 Scottish Generators or Interconnector Asset Owners provide to The Company a forecast of the equivalent highest 'export' capacity figure. This data is required by The Company as the basis for setting TNUoS tariffs. The Company may request these forecasts in the November prior to the Financial Year to which they relate, in accordance with the CUSC. Additionally users who are Generators provide to The Company details of their generation plant type.

14.19.2 Users who are owners or operators of a User System (e.g. Distribution companies) provide a forecast for the following Financial Year of the Natural Demand attributable to each Grid Supply Point equal to the forecasts of Natural Demand under both Annual Average Cold Spell (ACS) Conditions and a forecast of the average metered Demand attributable to such Grid Supply Point for the National Grid Triad. This data is published in table 2.4 of the Seven Year Statement and is compiled from week 24 data submitted in accordance with the Grid Code.

14.19.3 **The BSCCo** will provide data to **The Company** with respect to **Final Demand Site** counts and **Unmetered Supply** volumes to enable the development of the **Transmission Demand Residual Tariffs.**

~~14.19.2~~14.19.4 For the following Financial Year, The Company shall use these forecasts as the basis of Transmission Network Use of System charges for such Financial Year. A description of how this data is incorporated is included in 14.15 Derivation of the Transmission Network Use of System Tariff.

~~14.19.3~~14.19.5 If no data is received from the User, then The Company will use the best information available for the purposes of calculation of the TNUoS tariffs. This will normally be the forecasts provided for the previous Financial Year.

Data Required for Calculating Users' Charges

~~14.19.4~~14.19.6 In order for The Company to calculate Users' TNUoS charges, Users who are Suppliers shall provide to The Company forecasts of half-hourly and non-half-hourly demand in accordance with paragraph 14.17.14 and 14.17.15 and in accordance with the CUSC.

14.24 Example: Calculation of Zonal ~~Gross~~ Demand Locational Tariff

Let us consider all nodes in the same demand zone in this example

The table below shows an example output of the transport model comprising the node, the Peak Security and Year Round nodal marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

Where the Demand (MW) is negative this indicates that the Demand node is Exporting rather than importing.

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)
1	A	110	80	100
1	B	140	90	100
1	C	120	80	0
1	D	100	100	-50
1	E	100	70	50
		Totals		**200**

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Net Demand (MW)
14	ABHA4A	-77.25	-230.25	127
14	ABHA4B	-77.27	-230.12	127
14	ALVE4A	-82.28	-197.18	100
14	ALVE4B	-82.28	-197.15	100
14	AXMI40_SWEB	-125.58	-176.19	97
14	BRWA2A	-46.55	-182.68	96
14	BRWA2B	-46.55	-181.12	96
14	EXET40	-87.69	-164.42	340
14	HINP20	-46.55	-147.14	0
14	HINP40	-46.55	-147.14	0
14	INDQ40	-102.02	-262.50	444
14	IROA20_SWEB	-109.05	-141.92	462
14	LAND40	-62.54	-246.16	262
14	MELK40_SWEB	18.67	-140.75	83
14	SEAB40	65.33	-140.97	304
14	TAUN4A	-66.65	-149.11	55
14	TAUN4B	-66.66	-149.11	55
		Totals		**2748**

In order to calculate the gross demand tariff we would carry out the following steps:

i) Change Negative Demand values to 0 (zero) , which in this example is Node D

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)
1	A	110	80	100
1	B	140	90	100
1	C	120	80	0
1	D	100	100	0
1	E	100	70	50
		Totals		**250**

ii) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)	Peak Security Demand Weighted Nodal Marginal km	Year Round Demand Weighted Nodal Marginal km
1	A	110	80	100	44	32
1	B	140	90	100	56	36
1	C	120	80	0	0	0
1	D	100	100	0	0	0
1	E	100	70	50	20	14
		Totals		**250**	**120**	**82**

iii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 120km for Peak Security background and 82km for Year Round background.

iv)

i.) calculate the transport (locational) tariffs by multiplying the figures in (ii) above by -1. This changes the original Nodal Marginal Km for injecting (Generation) into Nodal Marginal Km for withdrawing (Demand). Then multiply by the expansion constant, the locational security factor and then divide by 1000 to put into units of £/kW:

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$-\frac{(120km * £10.07/MWkm * 1.8)}{1000} = -\mathbf{£2.47/kW}$$

b) Year Round tariff -

$$-\frac{(82 * £10.07/MWkm * 1.8)}{1000} = -\mathbf{£1.49/kW}$$

The Locational signal for Demand within this zone is negative for both Peak and Year Round, which indicates withdrawing at this part of the network, reduces total system flows.

ii.) A NHH locational demand element is calculated in accordance with the methodology given in 14.16.2.

v)

We now need to calculate the ~~residual~~ **Transmission Demand Residual T~~t~~ariffs**.

i.) This is calculated by first taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year) less the revenue which would be recovered through the demand ~~transport~~ locational and energy tariffs and revenue recovery through embedded export tariffs.~~, divided by total expected gross GSP group demand~~.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from ~~gross~~ GSP group demand locational ~~transport~~ and energy tariffs is £140m, total recovery from embedded export tariffs is -£10m the total revenue to be recovered through the **Transmission Demand Residual Tariffs** will be as follows:~~and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:~~

$$\cancel{\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW}$$

$$£779m - £140m - -£10m = £649m$$

ii.) The total revenue to be recovered from the **Transmission Demand Residual Tariffs** as calculated in (i) above is then apportioned between the **Charging Bands** as set in 14.15.137 by the sum of the annual energy consumption of the **Final Demand Sites** or **Unmetered Supplies** as appropriate allocated to a **Charging Band** as divided by the total annual energy consumption from all GB **Final Demand Sites** and **Unmetered Supplies**.

iii.) An example is as follows:

The total annual consumption of all GB **Final Demand Sites** and **Unmetered Supplies** is 100TWh.

The sum of the annual energy consumption of all **Final Demand Sites** in HV Charging Band 1 is 1TWh.

Using the example of total revenue to be recovered through the **Transmission Demand Residual Tariffs** above of £649m, HV Charging Band 1 **Final Demand Sites** will be liable for 1% of this cost.

The annual cost per site will be $\frac{£6{,}490{,}000}{N}$ where N is the total number of sites in HV Charging Band 1.

If, in this example, N = 12,000 the annual charge per **Final Demand Site** in HV Charging Band 1 will be £540.83.

The **Transmission Demand Residual Tariff** per **Final Demand Site** in HV Charging Band 1 will be set as a daily charge. The annual charge, in this example £540.83, will be divided by the number of days in the charging year to deliver a **Transmission Demand Residual Tariff** (£/site/day).

In this example: $\frac{£540.83}{365\ \text{days}}$ or £1.48/site/day.

~~ii) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))~~

~~For zone 1:~~

~~-£2.47/kW + -£1.49/kW + £12.98/kW = **£9.32/kW**~~

~~To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.~~

(vi) The ~~final demand~~**Transmission Demand Residual T~~t~~ariff** is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

	Forecast HH Triad Gross Demand HHD_F (kW)	HH Gross Demand Monthly Invoiced Amount (£)	Forecast HH Triad Embedded Export $HHEE_F$ (kW)	HH Embedded Generation Monthly Invoiced Amount (£)	Forecast NHH Energy Consumption $NHHC_F$(kWh)	NHH Monthly Invoiced Amount (£)	Net Monthly Invoiced Amount (£)
Apr	12,000	10,000	-600	(250)	15,000,000	15,000	24,750
May	12,000	10,000	-600	(250)	15,000,000	15,000	24,750
Jun	12,000	10,000	-600	(250)	15,000,000	15,000	24,750
Jul	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Aug	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Sep	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Oct	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Nov	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Dec	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Jan	7,200	(6,000)	-600	(250)	18,000,000	19,000	12,750

Feb	7,200	(6,000)	-600	(250)	18,000,000	19,000	12,750
Mar	7,200	(6,000)	-600	(250)	18,000,000	19,000	12,750
Total		72,000		(3,000)		216,000	297,000

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = (HHD_A - HHD_F) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

= £18,000

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

$$\text{NHHC Reconciliation Charge} = \frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$$

$$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$$

$$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 = £500 - £12,000).

Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand = (9,500kW - 9,000kW) x £10.00/kW

Reconciliation Charge = £5,000

Final HH Embedded Export = (-550kW - -500kW) x £5.00/kW

Reconciliation Charge = -£250
Final NHH Reconciliation Charge = (16,700,000kWh – 17,000,000kWh) x 1.20p/kWh

100

= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1, 150 (£5,000 + -£250 + -£3,600)..

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

Terminology:

HHD_A = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

HHD_F = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$HHEE_A$ = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$HHEE_F$ = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$NHHC_A$ = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

$NHHC_F$ = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

£/kW Tariff = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

p/kWh Tariff = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

14.29 Stability & Predictability of TNUoS tariffs

Stability of tariffs

The Transmission Network Use of System Charging Methodology has a number of elements to enhance the stability of the tariffs, which is an important aspect of facilitating competition in the generation and supply of electricity. This appendix seeks to highlight those elements.

Each node of the transmission network is assigned to a zone. The result of this is to dampen fluctuations that would otherwise be observed at a given node caused by changes in generation, demand, and network parameters. The criteria used to establish generation zones are part of the methodology and are described in Paragraph 14.15.42.

These zones are themselves fixed for the duration of the price control period. The methodology does, however, allow these to be revisited in exceptional circumstances to ensure that the charges remain reasonably cost reflective or to accommodate changes to the network. In rare circumstances where such a re-zoning exercise is required, this will be undertaken in such a way that minimises the adverse impact on Users. This is described in Paragraph 14.15.45.

In addition to fixing zones, other key parameters within the methodology are also fixed for the duration of the price control period or annual changes restricted in some way. Specifically:

- the expansion constant, which reflects the annuitised value of capital investment required to transport 1MW over 1km by a 400kV over-head line, changes annually according to RPI. The other elements used to derive the expansion constant are only reviewed at the beginning of a price control period to ensure that it remains cost-reflective. This review will consider those components outlined in Paragraph 14.15.59 to Paragraph 14.15.69.

- the expansion factors, which are set on the same basis of the expansion constant and used to reflect the relative investment costs in each TO region of circuits at different transmission voltages and types, are fixed for the duration price control. These factors are reviewed at the beginning of a price control period and will take account of the same factors considered in the review of the expansion constant.

- the locational security factor, which reflects the transmission security provided under the NETS Security and Quality of Supply Standard, is fixed for the duration of the price control period and reviewed at the beginning of a price control period.

- the **Transmission Demand Residual Charging Bands** which are used in setting **Transmission Demand Residual Tariffs** are fixed for the duration of the **Transmission Owner** price control period and reviewed at the beginning of a price control period

Predictability of tariffs

The Company revises TNUoS tariffs each year to ensure that these remain cost-reflective and take into account changes to allowable income under the price control and RPI. There are a number of provisions within the Transmission Licence and the CUSC designed to promote the predictability of annually varying charges. Specifically, The Company is required to give the Authority 150 days notice of its intention to change use of system charges together with a reasonable assessment of the proposals on those charges; and to give Users 2 months written notice of any revised charges. The Company typically provides an additional months notice of revised charges through the publication of "indicative" tariffs. Shorter notice periods are permitted by the framework but only following consent from the Authority.

These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority's veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

To supplement this, The Company also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years.[1] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- an explanation of the events that have caused tariffs to change;
- sensitivity analysis to indicate how generation and demand tariffs would change as a result of changes in generation and demand at certain points on the network that are not included within the SYS;
- an assessment of the compliance with the zoning criteria throughout the five year period to indicate how generation zones might need to change in the future, with a view to minimising such changes and giving as much notice of the need, or potential need, to change generation zones; and
- a complete dataset for the DCLF Transport Model developed for each future year, to allow Users to undertake their own sensitivity analysis for specific scenarios that they may wish to model.

The first year of tariffs forecasted in the annual information paper are updated twice throughout the proceeding financial year as the various Transport and Tariff model inputs are received or amended. These updates are in addition to the Authority 150 days notice and publication of "indicative" tariffs.

The parameters used in the calculation of generation cap (in paragraph 14.15.5 v.)) will be published along with the forecast and confirmed values in the Tariff Information Paper which is produced in compliance with Condition 5 (of the NGC's proposed GB electricity transmission use of system charging methodology - the Authority's decisions document March 2005 80/5).

In addition, The Company will, when revising generation charging zones prior to a new price control period, undertake a zoning consultation that uses data from the latest information paper. The purpose of this consultation will be to ensure tariff zones are robust to contracted changes in generation and supply, which could be expected to reduce the need for re-zoning exercises within a price control period.

[1] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/