Theme 1 - Reflecting characteristics of transmission users National Grid Proposal for Working Group Discussion

Executive Summary

On 7th July 2011, following industry discussion and consideration of several academic reports, Ofgem announced the launch of a Significant Code Review (SCR) on the electricity transmission charging issues under Project TransmiT, and specifically on charging arrangements that seek to recover the cost of providing electricity transmission assets, i.e. Transmission Network Use of System (TNUoS) charging. The SCR focuses on two potential changes to TNUoS charges: (i) postage stamp charging and (ii) improvements to the existing Investment Cost Related Pricing (ICRP) methodology. Six themes of potential changes are identified in the SCR terms of reference for the industry technical working group. The first theme is entitled 'reflecting characteristics of transmission users'. This paper sets out a strawman proposal produced by National Grid, which seeks to provide a solution to this specific issue and, in particular, within the existing ICRP methodology for discussion within the working group.

The SCR consultation has indicated a desire for potential TNUoS methodology improvements to be delivered by April 2012. Mindful of this, in an attempt to maximise the probability of successful Spring 2012 implementation, this proposal has been intentionally developed to be as simple as practicable. These simplifications preclude the development of a more detailed cost-benefit approach to the TNUoS charging methodology.

This proposal is built on the premise that, whilst there is a continuing need for transmission investment to ensure that there is sufficient capacity to secure GB demand at peak periods, there is also an increasingly significant requirement to develop the transmission system on an economic basis through consideration of year round cost-benefit analysis of infrastructure investment against operational costs. When considering such transmission development, generation which operates as a baseload unit will inherently trigger a larger level of investment than a low load factor generator..

There are two main aspects to this proposal;

- Consideration of year round cost-benefit development of the transmission system within the existing ICRP methodology in parallel with the existing demand security background. This would be through introduction of a second generation and demand condition representative of the economic development of the GB transmission system. This proposal uses concepts developed by the working group for proposed intermittency changes to the NETS SQSS. The proposed generation and demand conditions for this background are those developed by the SQSS review.

- Introduction of an annual load factor (ALF) for generation users which would enable those who utilise the system less to receive reductions in the wider locational element of their TNUoS charge. This reduction would reflect the level of transmission investment triggered by their reduced year round operation on a cost-benefit basis. It would be derived through consideration of their historical output over the previous five years of operation. Generic generation data for different technologies would be utilised for new users.

This strawman proposal follows the charging proposal raised last year in Use of System Charging Methodology Consultation GB ECM-25 'Review of Intermittent Generation Charging'. Whilst the underpinning methodology to GB ECM-25 had a broad level of industry acceptance, its apportionment to intermittent generation only was considered to be potentially discriminatory. Through a significant amount of further analysis and development, this issue has been addressed by allowing application of the methodology across all generation users.

This proposal focuses on generation users and has no impact on demand users.

1. Background

1.1 Economic development of the GB transmission system

There is an increasing requirement for future infrastructure development of the GB electricity transmission system to be justified on an economic basis. As increased levels of new generation connect to the system power flows across the system will change, and can result in the potential for circuits to be overloaded in certain circumstances. In the short term, without network reinforcement, such overloads can be managed through operational intervention, through constraining generation output such that power flows are actively managed. Such constraints require payments to be made to affected generation parties. As more generation connects, there is a point when it becomes more economic to build additional transmission capacity to avoid increasing levels of constraints. This is a long run cost to the industry as the impact is charged back over the lifespan of the assets. This balancing of short run operational costs against long run transmission investment costs is illustrated diagrammatically below in Figure 1.

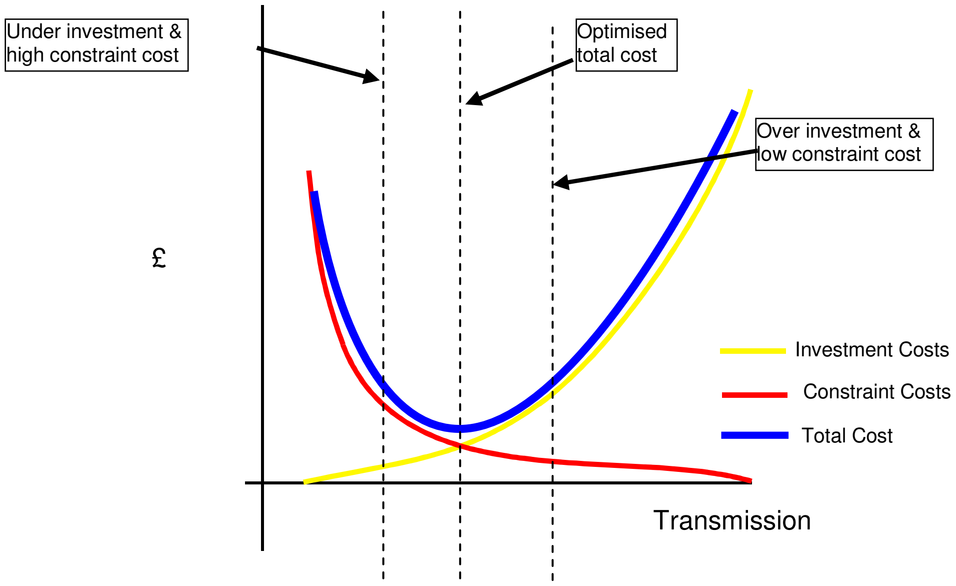

Fig.1 – Illustration of efficient balancing of operational vs investment costs

Historically the GB transmission system has been developed against a conventional generation background in accordance with the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS). Consideration of the amount of transmission network required has been based on the capacity needed to allow conventional plant to meet peak demand. Given the future changes to the GB generation mix, the NETS SQSS is currently under review to reconsider whether the existing methodology is still appropriate. The NETS SQSS working group has undertaken analysis that demonstrates that intermittent generation cannot be relied on to secure demand at any specific time. As a result, an increasing proportion of conventional generation will be required to supply demand when intermittent units are not available. With the associated increase in plant margin (installed generation capacity over peak demand) and changing power flows throughout the year the network investment required will be assessed using a year round cost-benefit approach, where the network investment costs are balanced against increased costs of operating the system. Consequently the NETS SQSS review group work has recommended that, when determining the requirement for new transmission capacity build, two separate backgrounds should be assessed:

- ○ <u>Demand security criterion</u>

  This will identify the transmission capacity required to secure demand at system peak, using conventional generation. Intermittent generation is removed from the generation background.

- ○ <u>Economy criterion</u>

  This balances the costs of reinforcing the transmission network against the potential system constraint costs that would otherwise be incurred. This will then identify the occasions when transmission network reinforcement is the more efficient option for the GB consumer.

The NETS SQSS review group work has demonstrated that full year round cost-benefit analysis of the GB transmission system can be reduced to consideration of a single generation and demand snapshot condition. A series of generation type scaling factors have been derived through the group's work in order to produce this single background condition. This analysis also provides a linkage between the short run cost of constraints and the required optimum level of transmission investment.

1.2 The link between system usage and transmission investment requirements

Analysis undertaken earlier this year, and discussed with industry at TCMF, has suggested, in the medium term, a link between a generator's load factor and the level of constraints attributed to it. Fig.2 below gives a graphical summary of those results on a 2011/12 background for the B6 boundary. The two charts relate to outputs from two different models used in the analysis, namely the Electricity Scenario Illustrator and the SQSS Intermittency models.

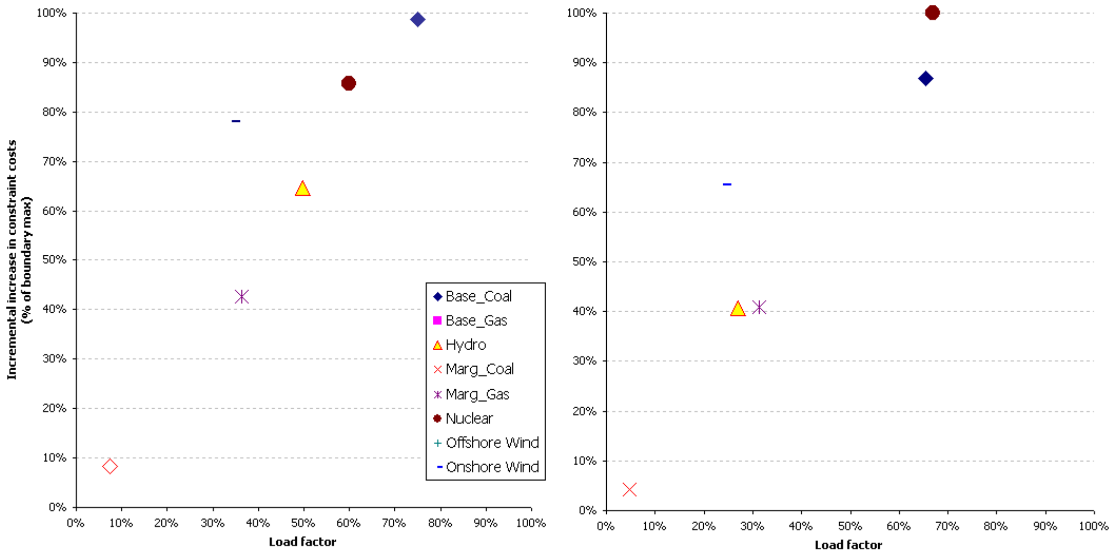

Fig.2 – Relationship between load factor and constraints incurred

The linear relationship derived by both models suggests a level of correlation between load factor and constraints. Extrapolating the SQSS intermittency proposals, and the underlying relationship between constraints and transmission investment over time, it can be estimated that a generator's usage of the system over time would provide a level of proxy to the required amount of transmission investment justified under cost-benefit analysis.

2. Proposed Treatment of Cost - Benefit Analysis within ICRP

The locational element of the TNUoS wider charge is calculated through consideration of the relative impact of an additional MW, applied nodally, on a DC load flow. Currently, the setting of this DC load flow is based on a peak security background, with all contracted generation uniformly scaled to match the peak MW demand.

Under this proposal, a snap-shot year round background would be used alongside peak security considerations, for future system development requirements. This year round background would group generation into types based on their technology and perceived future operating regimes, and then either flat or variably scale their aggregated capacity to meet demand. The level of scaling is shown in Table 1 below with flat scaling in black, and variable scaling in grey. It should be noted that the peak security background sets intermittent generators and interconnectors to zero, i.e. it assumes no contribution from energy sources that cannot be controlled. The scaling factors given in Table 1 are a result of the detailed cost-benefit analysis work undertaken by the NETS SQSS review group in an attempt to represent investment requirements for year round conditions in a single snap-shot.

It is proposed that the scaling factors given in Table 1 are treated similarly to other charging data which may change with time (e.g. expansion constant) and that it be reviewed at each Price Control Review (PCR). If the NETS SQSS intermittency proposals currently being considered are accepted, and similar scaling factors are used within the NETS SQSS, then it is proposed that future revisions of scaling factors for charging will be aligned with any revised NETS SQSS scaling. In the event that the NETS SQSS intermittency proposals do not proceed, then the underlying cost-benefit analysis work undertaken by the review group will continue to represent an acceptable approach to ascertain the figures required to provide a single snapshot of year round operation. It is considered that this proxy for cost-benefit analysis based network reinforcement is a significant improvement on the cost reflectivity of the existing charging methodology.

Generator type	TEC	Current methodology	Peak Security Background	Year Round Background
Intermittent	5,460	65.5%	0%	70%
Nuclear & CCS	10,753	65.5%	72.5%	85%
Interconnectors	3,268	65.5%	0%	100%
Hydro	635	65.5%	72.5%	66%
Pumped Storage	2,744	65.5%	72.5%	50%
Peaking	5,025	65.5%	72.5%	0%
Other (Conventional)	61,185	65.5%	72.5%	66%

Table 1 – Proposed ICRP generation background scaling factors (source 2011/12 Transport Model)

In the above table, peaking plant is defined as oil and OCGT technologies. In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) will apply.

Utilising the existing transport model, generation will be scaled, or set, as appropriate using the factors in Table 1 to create two balanced DC load flow models. It should be noted that, consistent with the current DC load flow model, no circuit ratings would be considered, and no level of redundancy would be assessed at this stage. In the rare event that both triggering criteria give rise to identical circuit flows, then the peak security background will be taken as the triggering criterion. This reflects the order of priority given to these two backgrounds when considering transmission investment requirements.

Flows on these two models will then be compared. The model giving rise to the higher flow on a circuit will be considered to be the ‘triggering criterion’. Triggering criteria for all circuits in the model will then be ascertained and recorded, i.e. circuits will be tagged as either ‘peak security’ or ‘year round’.

Under the current ICRP methodology, an incremental MW is applied to the DC load flow at each node in turn (and removed at the slack), in order to establish the effect of that additional MW on the transmission system as a whole. Under the proposed methodology, this assessment would be carried out at each node in turn for both peak security and year round models. On a circuit by circuit basis, the impact of the incremental MW (i.e. the net change in power flow) needs to be recorded for each circuit's triggering criterion. For each circuit an incremental MWkm needs to be established and tagged to the appropriate triggering criterion, i.e. peak security or year round.

Finally, the incremental MWkm for demand security and year round backgrounds need to be converted into tariffs. Ultimately this will lead to the creation of two wider locational tariffs;

- *Peak Security Wider Tariff.* It is proposed that the peak security wider tariff for intermittent generation will be zero due to intermittent generation's lack of contribution to the need for network investment to ensure demand security.
- *Year Round Wider Tariff.* It is proposed that this tariff is scaled by an annual load factor (ALF) specific to a particular generator. Further details on the derivation of ALF are provided in section 3 below.

Further details on tariff production are given in section 5 of this report.

A summary of the proposed process is given below in Fig.3.

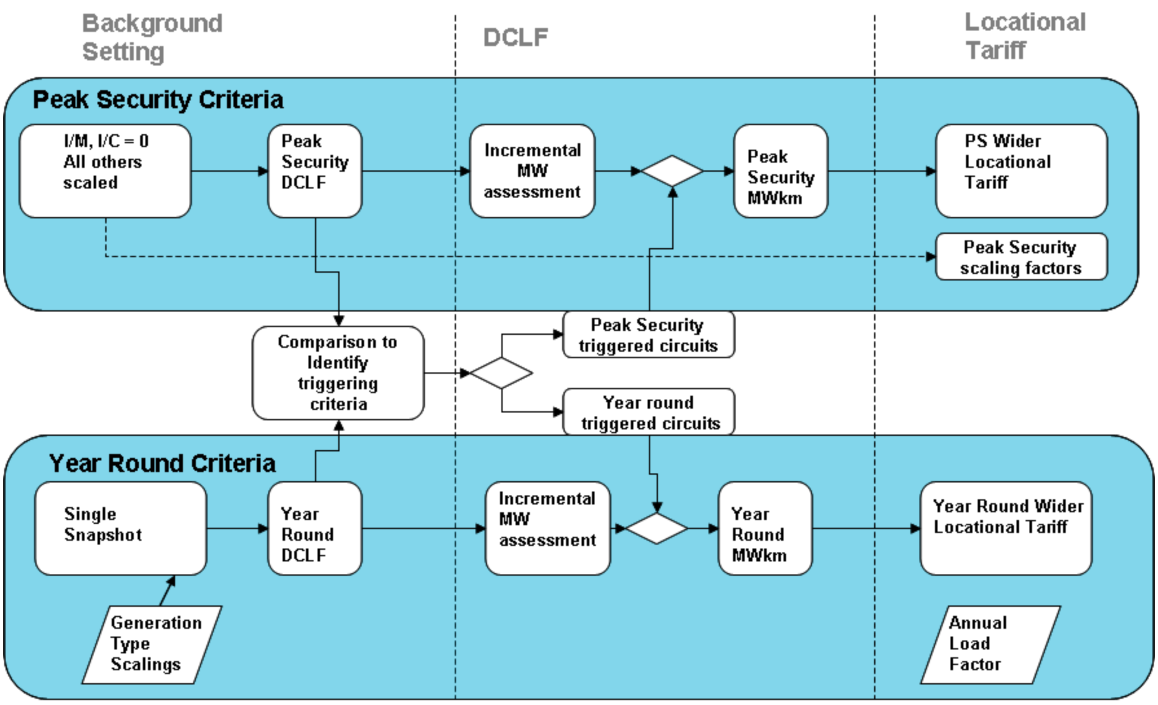

Fig.3 – Proposed dual background TNUoS charging methodology

3. Proposed Annual Load Factor (ALF) Methodology

In this proposal, a generator's forecast ALF is based on their historical output over the last five years. The forecast ALF is used to scale a generator's year round wider locational TNUoS charge, i.e. the charge based on its year round operation.

The ALF is taken to be indicative of a user's operating regime over a twelve month period, and therefore its effect on investment required for year round operation of the system, as set out in Section 1.2 above. As such it does not need to be an accurate reflection of the actual output over a particular twelve month charging period. Whilst several potential options exist for the calculation of the ALF based on either forecast or historical load factor, this strawman proposal puts forward a fixed, historical based approach. Therefore, there is no requirement for an end of year reconciliation. The benefits of this fixed approach are added certainty and stability as a result of increased predictability of tariffs and accuracy of within year revenue collection.

3.1 Calculation of User Specific ALF

Historic annual load factors are calculated for each of the last five complete financial years (years -5 to -1) using the formula below;

$$ALF = \frac{MWhr\_O_{utput}}{TEC * 8760}$$

The TEC figure used in each calculation will be the highest TEC applicable to that power station for that financial year. The MWhrs output figure will be derived from published historic user data available to National Grid.

Once all five historic load factor figures have been calculated they are compared, and the highest and lowest figures are discarded. The discarding of these outermost figures ensures that the final ALF is representative of an indicative operating regime for a particular generator, and has not been influenced by atypical behaviours. Such behaviours can range from unseasonal weather conditions through to response to System Operator instructions.

The ALF, to be used for charging purposes, is calculated as the average of the remaining three historic load factor figures. The process, with example figures, is illustrated in Fig. 4 below.

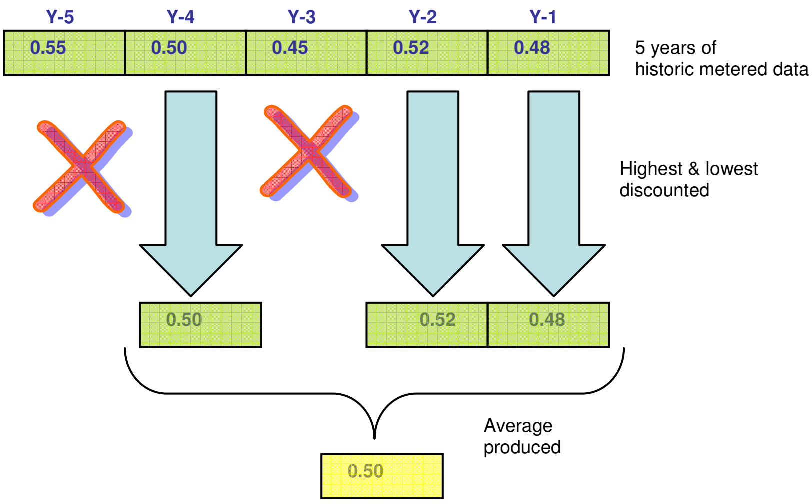

Fig.4 – Process for deriving user specific ALF

In the event that only four years of complete metered data are available for a user the higher three years load factor would be used in the calculation. In the event that only three years of complete metering data are available then these three years would be used.

Due to the aggregation of metered data for dispersed generation (e.g. cacade hydro schemes), where a single generator BMU consists of geographically separated power stations, the annual load factor will be calculated based on the total output of the BMU and the overall TEC of the BMU.

3.2 Derivation of generic generator data

In the event that there are not three full years of a generator's output available, missing historical information will be replaced by generic data for that generator type to ensure three years of information are available for the user.

Generic data is derived from the average annual output of all GB generation of a particular fuel type over the last five years, using an identical methodology to that used for the user specific calculation. Proposed fuel type categories and illustrative data are listed in Table 2 below;

Fuel Type	Generic Load Factor
Biomass	N/A
Coal	43%
Gas	57%
Hydro	12%
Nuclear	60%
Oil	2%
Pumped Storage	15%
Wind	16%

Table 2 – Fuel Type Categories to be used to derive generic load factor

For new and emerging technologies, where insufficient data is present to allow a generic load factor to be developed from historic information, a generic load factor will be produced by National Grid using its agreed forecast modelling tool. At the point of writing, it is anticipated that this will be either Plexos or the Electricity Scenario Illustrator developed by National for RIIO-T1 engagement.

Generic load factors will be reviewed annually in the period November – December (i.e. at the same time as user specific ALFs) and will be presented, in a form similar to Table 1 above, within the Statement of Use of System Charges (the Charging Statement).

It should be noted that for new generation connecting mid-year, a pro-rated ALF will be derived using the figures in Table 2. When used for this purpose, it is assumed that the output of the generator is apportioned evenly across a twelve month period.

3.3 Proposed Timeline

ALF forecasts are provided to generation users at the same time as draft TNUoS tariff are published. The full proposed timeline is described in Fig. 5.

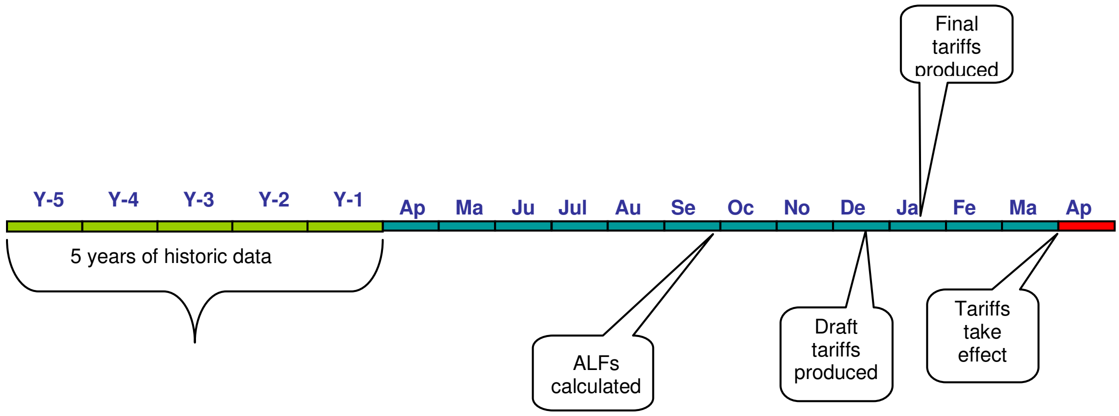

Fig.5 – Timeline for proposed strawman process

5. Production of Tariffs

Under this proposal a generator's TNUoS charge would be comprised of the following components;

- Peak security wider zonal charge
- Year round wider zonal charge
- Residual charge
- Local substation charge
- Local circuit charge

It is not proposed that the local substation nor the local circuit tariffs are altered as a result of this strawman as network investment requirements for these elements are not affected by load factor in the same way as the wider network. Nevertheless, the extent to which circuits are defined as local or wider is currently under discussion in the working group. Derivation of the other three tariffs is discussed below.

5.1 Setting of generation zones

The current methodology for setting of generation zones describes three criteria for zonal assessment. Specifically, the first criterion requires that zones should contain relevant nodes whose wider marginal costs are all within +/-£1.00/kW across the zone (i.e. a £2.00/kW spread). Under this proposal it is recommended that zonal assessment continues to be undertaken such that wider marginal costs are within +/-£1.00/kW.

It should be noted that, unless there are exceptional circumstances, generation zones are normally fixed for the duration of a price control period. It is therefore recommended that there is no zonal reassessment until the next price control review period.

Zoning criteria remains subject to debate and development within the working group (Theme 2). Any changes arising out of deliberation by the working group can be incorporated into a strawman model at this stage in the process.

5.2 Wider locational tariffs

In order to allow for tariff calculation across two backgrounds and ensure revenue is recovered in the correct proportions from generators and suppliers, it is necessary in the first step of the calculation for both peak security and year round wider locational charges to give a net revenue recovery of zero, i.e. that negative generation charges will be balanced by positive generation charges. Therefore, the overall process for derivation of wider locational tariffs consists of converting marginal MWkm into unadjusted tariffs, and then re-referencing this output to ensure the overall revenue recovery is zero. This process is identical for both peak security and year round wider locational tariffs.

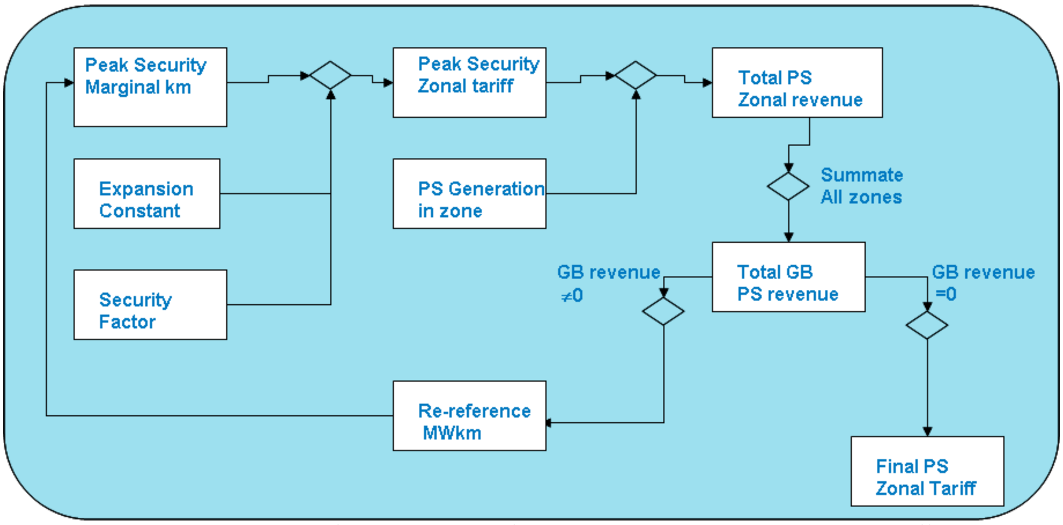

Fig.6 – Process for derivation of peak security wider locational tariff

Figure 6 illustrates the process of setting the peak security zonal tariff. This process is described in more detail below.

5.2.1 Derivation of unadjusted Zonal Tariffs

The outputs of the transport model are the zonal marginal km, which form the input into this process. These marginal MWkm are converted into unadjusted peak security zonal tariffs through multiplication by the expansion constant and the locational security factor. This is no different to the existing process for tariff derivation. However, if this process alone were used for tariff production, this would result in a net GB revenue recovery for the peak security criterion. Hence it is proposed that the initial tariffs are adjusted such that the overall revenue recovered is zero. This is necessary in order that when overall revenue recovery from the final tariff is apportioned across generators and suppliers, the correct split in revenue recovery occurs.

5.2.2 Calculation of unadjusted Zonal Revenue

When readjusting these initial tariffs to ensure the overall revenue recovered is zero, the expected revenues that would be collected through these unadjusted tariffs need to be calculated and then summated to find a projected overall GB revenue.

The revenue from a specific generator due to the peak security locational tariff is equal to that tariff multiplied by the forecast generation capacity provided by the User. This also needs to be multiplied by the appropriate peak security flag. The peak security (PS) flags indicate whether a generation type contributes to the need for network investment at peak demand levels. As such, they are consistent with the background generation scalings used in the peak security transport model assessment (see Table 1), and are given below in Table 3.

Generation type	PS scaling factor
Intermittent	0
Other	1

Table 3 – Peak Security Scaling Factors

The chargeable capacity for peak security purposes of a generator is calculated as;

$$ITRR_{GiPS} = G_{Gi} \times SF_{PS} \times ITT_{GPS}$$

Where; $ITRR_{GiPS}$ = Initial Transport Revenue Recovery for generator i due to System Peak criterion

G_{Gi} = Forecast generation capacity

F_{PS} = Peak security flag appropriate to that generator type

ITT_{GPS} = Initial Transport Peak Security Tariff (£/kW)

In the case of the year round locational tariff it is proposed that historic generation annual load factors (ALF) be used as scaling factors, as set out in Section 3, above.. For clarity, the formula for chargeable capacity for year round charging purposes is calculated as below;

$$ITRR_{GiYR} = G_{Gi} \times ITT_{GYR} \times ALF_{gen}$$

Where; $ITRR_{GiYR}$ = Initial Transport Revenue Recovery for generator i due to Year Round criterion
G_{Gi} = Forecast generation capacity
ITT_{GYR} = Initial Transport Year Round Tariff (£/kW)
ALF = Annual load factor relevant to generator

In order to produce the expected zonal revenue, the initial revenue recovery for each generator within that zone is summated. The total net GB peak security revenue is taken as the sum of the individual zonal revenues. If the total net GB peak security revenue equals zero, then the wider locational peak security tariffs can be used as the final tariffs.

Note that for both criteria, the revenue recovery from interconnector operators is zero.

5.2.3 Re-referencing process

If the total projected GB peak security revenue is not equal to zero, then the peak security zonal MWkm need to be re-referenced to ensure an overall revenue recovery from the peak security criterion is zero.

This re-referencing value is known as the MWkm Peak security Re-referencing Quantity, and is calculated from the formula below;

$$MWkm_{RQPS} = \frac{\left(\sum_{Gi=1}^{20} R_{PSGi}\right)}{EC \times LSF \times \sum_{Gi=1}^{20} G_{PSGi}}$$

Where; $MWkm_{RQPS}$ = MWkm peak security re-referencing quantity
R_{PSGi} = Projected revenue from peak security tariff for generation zone i
G_{PSGi} = Chargeable capacity of generation for peak security purposes in zone i
EC = expansion constant
LSF = locational security factor

The MWkm peak security re-referencing quantity is added to each of the zonal weighted marginal MWkm to give re-referenced values. These re-referenced values are then taken through the processes described in sections 5.2.1 and 5.2.2. The total net GB peak security revenue recovery will be zero at this point and the re-referenced peak security locational tariffs can be taken as the final tariffs.

The re-referencing process for the year round wider locational tariffs is identical to this process.

5.3 Relevant Chargeable Capacities for Generator Charge Calculations

It is proposed that, for the peak security criterion, there is no change to the existing definitions of chargeable capacity. Hence, the chargeable capacity for power stations with a positive wider peak security tariff will be the highest TEC applicable to that power station for that financial year. The chargeable capacity for power stations with negative wider generation tariffs would continue to be the average of the capped metered volumes during three settlement periods of the highest and next highest metered volumes which are separated from each other by at least 10 Clear Days, between November and February of the relevant Financial Year inclusive. These settlement periods do not have to coincide with the Triad.

It is proposed that, for the year round criterion, the chargeable capacity for all power stations would be based on the highest TEC applicable to that power station for the financial year. This is correct for the year round criterion, as the load factor used in tariff calculation has been calculated on the TEC of the power station rather than its highest output during the winter period.

5.4 The Residual Tariff

As the net wider locational tariffs for both peak security and year round criteria have been set to recover net GB revenue of zero, the setting of the residual charge becomes an extremely simple exercise.

Assuming that the revenue to be collected from generator users is 27% of total infrastructure revenue, the required revenue to be recovered from the generation residual charge can be calculated as;

$$R_{RG} = 0.27T_{tot} - R_{LS} - R_{LC}$$

Where; R_{RG} = required revenue from generation residual charge
T_{tot} = total infrastructure revenue
R_{LS} = revenue from local substation charges
R_{LC} = revenue from local circuit charges

The £/kW residual charge can then be calculated from division of this required revenue by the chargeable generation capacity which, for the residual charge, is proposed to be equal to the total GB Transmission Entry Capacity of connected generation.

Depending on working group discussions on the split of revenue recovery between generation and demand users (Theme 6), the calculation of the residual can be modified to accommodate whatever ratio the group deem appropriate within a strawman improved ICRP model.