nationalgrid

# CONCLUSIONS REPORT

## GB ECM-11

## For the charging arrangements for Generator Local Assets

**15 September 2008**

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## 1. Executive Summary

This conclusions reports sets out National Grid's proposals for modifying the Transmission Network Use of System (TNUoS) charging methodology to achieve the following objectives:

- to disaggregate the Transmission Network Use of System charge into well defined local and wider locational components; and
- to improve the cost reflectivity of charging for assets local to generation connections.

A cost reflective signal is required for assets local to generation so Users choosing between differing levels of investment through SQSS variation to connection design provisions make decisions which result in the most efficient and economic outcome.

National Grid has previously published several consultations[1] relating to a TNUoS discount mechanism for SQSS connection design variation connections. Such a discount represents the reduced infrastructure asset investment requirement for such connections, e.g. single spur connections. After an Authority veto decision[2] of the initial proposals and subsequent further analysis and refinement, the conclusion was reached that a more fully cost reflective discount signal would introduce inappropriate signals unless the basis of the associated charge is also made more fully cost reflective.

The charging amendment being presented in this Conclusions Report maintains the principle of charging generation local assets as infrastructure but splits the locational signal into wider and local components whilst applying a more specific treatment to the local component. It defines incremental flow on specific circuits as 'local'. Using cost reflective local security and expansion factors, a more cost reflective local charge is produced

This approach would be implemented in conjunction with a local substation charge, which charges a User for the primary assets at the connection substation using generic costs based on connection voltage, substation redundancy and total amount (MW) of generation connected at the connection substation.

It is proposed that local and wider charges for generation will be applied from 1 April 2009.

The document has been published on the National Grid charging website at the following address:

www.nationalgrid.com/uk/electricity/charges

## 2. Introduction

As the transmission licensee, authorised to co-ordinate and direct the flow of electricity onto and over the transmission system within Great Britain, National Grid has duties under the Electricity Act to develop and maintain an efficient, co-ordinated and economical transmission system and to facilitate competition in generation and supply.

[1] www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/
[2] http://www.nationalgrid.com/NR/rdonlyres/491F2854-660F-462C-9E0D-BAF41A8B7D7A/15284/GBECM06AuthorityDecisionLetter.pdf

Along with these high level duties, National Grid is obliged under its transmission licence:

(i) to keep the Use of System Charging and Connection Charging Methodologies at all times under review

(ii) to make such modifications of the Use of System Charging Methodology as may be requisite for the purpose of better achieving the relevant objectives, which are:

a) to facilitate effective competition in generation and supply;

b) to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;

c) in so far as is consistent with a) and b) above, as far as reasonably practicable, they properly take account of the developments in transmission licensees' transmission businesses.

(iii) to make such modifications of the Connection Charging Methodology as may be requisite for the purpose of better achieving the relevant objectives, which are

a) to facilitate effective competition in generation and supply;

b) to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;

c) in so far as is consistent with a) and b) above, as far as reasonably practicable, they properly take account of the developments in transmission licensees' transmission businesses;

d) in so far as is consistent with a), b) and c) above, of facilitating competition in the carrying out of works for connection to the GB transmission system.

In addition to the relevant objectives above, the transmission licence also prohibits National Grid from discriminating against any user or class of users unless such different treatment reasonably reflects differences in the costs of providing a service.

## 2 Terms of the original proposed modification

**Explanation of the issue**

The GB SQSS includes criteria for variations to connection designs. The criteria allow Generators or demand customers to choose a standard of connection which is higher or lower than the specified standard (e.g. a single circuit connection rather than a double circuit connection), provided this does not, either immediately or in the foreseeable future:

(i) reduce the security of the main interconnected transmission system below the minimum planning criteria specified in the standard;

(ii) result in additional investment or operational costs to any particular customer or overall, or a reduction in the security and quality of supply of the affected customers' connections to below the planning criteria in the standard, unless specific agreements are reached with affected customers; or

(iii) compromise the Transmission Licensees ability to meet other statutory or licence obligations.

For the example of a single circuit connection to a generator, in order to comply with the GB SQSS the generator would have to accept uncompensated access restrictions in the event that the single circuit is unavailable as a result of a fault outage or maintenance outage in order to meet these conditions. Without these arrangements, other customers would be exposed to additional operational (compensation) costs as a result of the single circuit connection and condition (ii) above would not be met.

The criteria for variations to connection designs also state that should system conditions subsequently change, for example due to the proposed connection of a new customer, such that either immediately or in the foreseeable future, the conditions described above are no longer satisfied, then alternative arrangements and/or agreements must be put in place such that the standard continues to be satisfied.

Prior to the implementation of the plugs 'shallow' connection Charging Methodology on 01 April 2004, many of the assets associated with generation connection were classified as 'connection'. Consequently, a customer choosing a lower standard of connection design had the capital savings directly reflected in connection charges. The customer was able to compare the savings with the loss of revenue caused by the associated access restrictions and choose the most efficient connection design.

Following the implementation of the plugs methodology, some assets for connecting generation were reclassified as 'infrastructure' and since infrastructure assets are funded from use of system rather than connection charges, the savings are no longer passed through directly to the customer, but shared amongst all.

***Description of proposed modification to the Use of System Charging Methodology***

National Grid is proposing to modify the TNUoS Charging Methodology to achieve the following objectives:

- to disaggregate the Use of System charge into well defined local and wider locational components; and
- to improve the cost reflectivity of charging for assets local to generation connections.

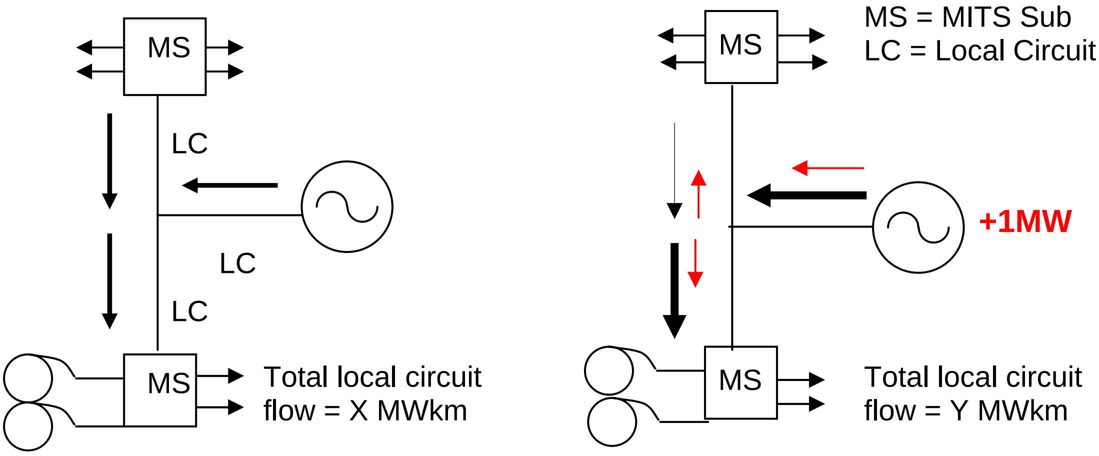
**Identification of Local / Wider boundary**

All generation that is subject to TNUoS and not connected directly to a Main Interconnected Transmission System (MITS) substation will have a circuit component to their Local Charge. A MITS substation is defined as:

- A Grid Supply Point (GSP) connection with 2 or more transmission circuits connecting at the substation; or
- More than 4 transmission circuits connecting at the substation,

where a GSP is defined as a point of supply from the GB Transmission system to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the GB transmission system between two or more circuit-breakers which includes, transformers, cables and overhead lines but excludes busbars and generation circuits.

The Local Charge is derived by examination of the power flows along the local generation circuits, where the local circuits are the connections between the generation node and the next MITS substations. The incremental flow along all local circuits is found by using the Direct Current Load Flow (DCLF) model. The model will compare the total marginal flow (in MWkms) along all the identified local circuits after the addition of an extra 1MW of generation at the connection node and 1MW of demand at the slack node, as shown in the diagram below. This approach is consistent with the approach used to determine the existing TNUoS locational tariffs and pictorially represented below:




**Circuit Local Charge = function of (Y-X MWkm)**

The total incremental local circuit flow can then be converted into a circuit component of the Local Charge:

Circuit Local Charge (£/kW) = Incremental local circuit flow (MWkm) x Local Security Factor x  Expansion Constant (£/MWkm)/ 1000

All generation with wider access rights remain liable for a wider zonal TNUoS charge which is calculated consistent with the existing methodology.

The incremental flow cost (MWkm) along the local circuits is subtracted from the wider zonal generation cost weighted average (MWkm) to avoid double counting.

For connections where the net incremental flow on the local circuits is negative i.e. the net flow on the local circuits is decreased by an increase in generator output; the local circuit charge will also be negative. Such payments will be treated in the same manner as existing negative generation TNUoS zones, namely; the chargeable capacity for power stations with negative local charge tariffs is the average of the capped metered volumes during the following three settlement periods: the highest metered volumes for the power station or interconnector and the two half hour settlement periods of the next highest metered volumes which are separated from the highest metered volumes and each other by at least 10 clear days, between November and February of the relevant financial year inclusive.

**Improving the cost reflectivity of the Local Charge**

**Local Expansion Factor** - More specific local expansion factors are applied in order to calculate the marginal flow on the local circuits. 132kV Overhead Line (OHL) costs have significant cost variance, therefore the single 132kV OHL expansion factor, is replaced by four local expansion factors based upon the two cost-determining variables of number of circuits per route and circuit capacity (continuous winter MVA rating). The table below shows the expansion factors that are to be applied to the local circuits in order to determine the incremental local flow and therefore the Local Charge.

Expansion factors are reviewed at each Price Control Review and remain constant during 5 year Price Control periods.  The Expansion Constant, the base £/MWkm cost for 400kV OHLs on which expansion factors are based, is also reviewed at each Price Control but is also inflated by RPI annually during a Price Control period.

| Circuit Capacity (MVA) | Construction | 132kV OHL Expansion Factor |
|---|---|---|
| <200 | Single | 10.000 |
| | Double | 8.319 |
| =>200 | Single | 7.134 |
| | Double | 4.423 |

**Local Security Factor** – The Local Charge has a Local Security Factor in order to take into account the degree of infrastructure redundancy provided for the local connection. For any of the local circuits, if the loss of the circuit would result in loss of access to the network, then the Local Security Factor applied is 1.0, whereas for other instances the Local Security Factor will be charged at the existing GB average Locational Security Factor value, currently 1.8.

**Local Substation component**
A substation Local Charge component will be payable by all generators. The generator's local connection substation will be categorised against three cost determining factors to determine its substation Local Charge tariff. A description of the cost factors and the feasible states are given below:

- **HV connection voltage** – The voltage of the first substation at the boundary between the User's connection assets and the transmission system.
    - 400kV, 275kV or 132kV and below
- **Sum of TEC at connecting substation** – The combined TEC of all generation at the connecting substation
    - Less than 1320MV, greater than 1320MW
- **Single circuit/ redundancy connection** – A single busbar / single switch mesh connection or a redundancy connection which includes a double busbar sub station design
    - Single circuit, redundancy connection

| | | **Substation Local Charge (£/kW)** | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| **<1320MW** | **Single** | **0.129** | **0.078** | **0.063** |
| **<1320MW** | **Double** | **0.291** | **0.186** | **0.150** |
| **>1320MW** | **Single** | **-** | **0.249** | **0.201** |
| **>1320MW** | **Double** | **-** | **0.404** | **0.325** |

The costs will be subject to a RPI increase each year and will be reviewed at each Price Control Review period. The additional revenue collected from the substation Local Charge would have the effect of reducing the size of the generation residual.

National Grid is proposing to modify Chapter 2: Derivation of the Transmission Network Use of System Tariff and Chapter 5: Generation charges, of the Statement of the Use of System Charging Methodology to include a mechanism by which generation will be subject to both a wider and a local tariff (including circuit and substation components) for use of transmission infrastructure assets.

The proposed Statement of Use of System Charging Methodology drafting for this modification is included in Appendix 1.

**Justification for proposed modification**

National Grid's proposal to modify the TNUoS Charging Methodology to provide a economic signal through a Local Charge (Option A) by which the capital saving associated with a single circuit design variation connection can be reflected, better meets the relevant objectives in Licence Conditions C5 5(b) and C5 5(c). Namely to ensure National Grid applies charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses and properly takes account of the developments in transmission licensees' transmission businesses.

The circuit component of the Local Charge reflects the distance related marginal cost of the generator's local connection and is derived using a specific local Security Factor and local expansion factors and is therefore consistent with the existing Charging Methodology. The existing 132kV OHL expansion factor is to be replaced with four local expansion factors in order to reduce the cost variances between actual OHL costs and applied expansion factor. The local expansion factors were calculated, taking account of data provided by the three transmission licensees.

The substation component of the Local Charge reflects the cost of the non-distance related infrastructure assets of a generation connection. The substation component is expressed as a £/kW tariff and has been derived from generic cost analysis that has been performed using data from the three transmission licensees to compare the substation costs associated with single busbar and double busbar connection designs at 132kV, 275kV and 400kV.

The substation and circuit components of the local charge are derived from the cost of the capacity booked rather than that installed, and therefore users will continue to be protected from the actions of other users and the design decisions of the relevant Transmission Owner, which could otherwise potentially be a barrier to market entry.

Both solutions considered in the Consultation, Options A and B, provide a cost reflective local signal that reflects local asset redundancy and specific local cost factors although Option A has advantages associated with transparency, simplicity and implementation impact (at a time of overarching review of transmission access arrangements). The solution is proportionate to the scale of the issue being addressed at this time, namely the provision of an economic signal for design variation connections. Option B may have some advantage in the accuracy of how post-fault power flows are considered, but implementation of Option A is the more practical solution at this time.

Of the generators currently liable to pay TNUoS, 38 are not directly connected at a MITS node and therefore would be liable to the circuit element of the Local Charge. 13 of these generators are considered to have a single circuit and therefore would have a Local Security Factor of 1.0 applied. No single circuit design variation connections are directly connected to a MITS node and therefore all are subject to a Local Charge signal.

**Suggested alternatives**

One respondent stated there were two improvements possible to Option A:

- Application of Transmission Owner specific local expansion factors that include the uprating factor

| |
|---|
| • Application of a connection specific local security factor, in order to accommodate partial redundancy<br><br>Another respondent suggested that Local Charge under Option A should be implemented without the substation component. |
| **Implementation date**<br><br>National Grid is seeking to implement this modification proposal to be applied from 1 April 2009. |
| **Proposed changes to the Statement of the Use of System Charging Methodology**<br><br>See Appendix 1 |
| **Impacts on other Industry Documents**<br><br>There are no impacts on other industry documents.<br><br>Users who currently have a connection offer in the GB queue may be interested in changing the connection design to a customer choice connection in light of the implementation of this proposal. The process to be followed should firstly be to contact National Grid to discuss the feasibility of such a connection and to ensure all the criteria, as described within the GB SQSS for design variation connections, are likely to be met. For example, it will be necessary to coordinate this with any other potential connectees at the node. The Modification Application process should be followed so as to cover the necessary study of the contracted background.<br><br>It is perceived that, assuming the modification does not affect other connections in the queue, this change of connection design should not effect the user's position in the queue or year of commissioning. |

## 3 Responses to the modification proposal

National Grid published a consultation document on 1st August 2008 which set out two options for splitting the TNUoS locational signal into wider and local components and applying a more specific treatment to the local component:

- **Specific treatment of generation connections (Option A)** – This defines incremental flow on specific circuits as 'local'. Using cost reflective local security and expansion factors, a more cost reflective local charge is produced
- **Distance to zonal hub (Option B)** – Each TNUoS zone contains a reference marginal cost and the marginal cost differential between each generator and this economic hub is the proposed basis of the local charge. Security is considered as the marginal costs are derived using a Secured DC Load Flow model.

It was proposed that either option would be implemented in conjunction with a local substation charge, which charges a User for the primary assets at the connection substation using generic costs based on connection voltage, substation redundancy and amount of generation connected.

National Grid received 14 written responses to this consultation document. The consultation document and industry responses can be viewed on the National Grid charging website.

**Summary of responses**

The majority of respondents supported the implementation of a Local Charging mechanism and supported the rationale behind such proposals. Of those expressing a preference, all but one of respondents preferred Option A to Option B, although several were on a 'least worse' basis. One respondent stated that stability and transparency are important in assessing modifications and was concerned that Option B created instant winners and losers. Another respondent, who supported both Options A and B, stated that a charging model that is as cost reflective as possible for both local and wider assets is an enhancement and as local assets are unlikely to be shared then its charge should be cost reflective.

A number of respondents agreed with the principle of splitting local and wider assets, in order to produce a more cost reflective local charge. One respondent agreed such an approach was a necessary building block for the introduction of new access products being considered as part of the transmission access review although was disappointed that both solutions result in higher charges for renewable generation in areas of resource which, in this respondent's view, will act as a further disincentive for additional generation projects.

Several respondents commented that a key objective of the charging modification was to incentivise the connection of new single circuit and new renewable connections and that as the TNUoS charges for many such existing generators in the north of Scotland actually increase under both options proposed then the objective of the amendment has not been met. A number of these respondents went on to state that this charging modification does not meet National Grid's Relevant Objectives as it is not simple, transparent or predictable and therefore these respondents are against the proposals and recommend that no charging modification should be submitted to the Authority. A response submitted by several parties stated that National Grid should postpone the submission of a conclusions report as there has been a very significant shift from the previous design variation discounts proposed and they have very strong concerns that the arrangements have not been tested against the future transmission access arrangements and further iterations will be required.

A respondent stated that neither the charging modification or the current Charging Methodology succeed in sending out an effective cost reflective locational signal to which generation can respond and does not support either. The same respondent believed the modification does not take into account recent developments in the industry and an alternative approach to transmission charging was proposed whereby Users would pick up a cost reflective 'local' infrastructure charge and a flat wider charge. Use of the compensation arrangements was also suggested as an alternative approach.

Another respondent who does not support the current Charging Methodology or the implementation of the modification, stated that the locational signal produced is neither balanced or proportional and contributes towards the very high charges faced by Scottish renewable generators. The respondent is concerned with National Grid's ongoing 'piecemeal' approach to modifying its Charging Methodology.

**National Grid's response**
As shown by the indicative tariffs for Option B in Appendix 6 of the Consultation, implementation of the Distance to Zonal Hub option results in some incremental changes to baseline TNUoS tariffs. This results from zonal charging being replaced by a nodal approach and the calculation and charging of security at a nodal level rather than at the GB average.

There is a balance to be achieved between the cost reflectively of the local charge and avoiding undoing the implementation of a shallow boundary. National Grid believes these proposals achieve as much cost reflectivity without unwinding "Plugs" and losing the advantages it provided to generators. Advantages include protecting Users from the cost of lumpy or strategic Transmission Owner investment and the actions of other Users, such as failing to connect to a shared connection site. In addition, the shallow "Plug" avoids the need for shared connection assets which would require an accurate connection asset apportionment methodology. It is difficult to define such a methodology that is robust and cost reflective because shared assets provide various roles at different times for different Users. For example demand and generation would use a shared connection spur very differently, as would a wind generator compared to a thermal unit.

For generation that has previously not been exposed to the full cost of their specific connection and has therefore benefited from the more averaged charging approach, the proposed specific local charge may lead to increased Use of System charges. As shown in Appendix 6 of the Consultation under Option B, 50 of the 102 generators that currently pay TNUoS would see a reduction in their TNUoS tariff, which is the effect of unwinding an average based approach.

The intention of the charging modification is to better meet National Grid's Relevant Objectives of cost reflectivity, facilitating competition and meeting the developments in the transmission business and not to incentivise the connection of any specific types of generator with lower TNUoS tariffs, as this would represent discrimination under Licence Condition C7.

The signal for design variation decisions must be calculated on the same basis as the locational signal so as to avoid an inappropriate signal, that incentivises Users to trigger inefficient transmission investment. National Grid believes the implementation of Option A is an efficient solution proportional to the scale of the issues being addressed at this time, namely the simple and transparent provision of an economic signal for design variation connections. The solution modifies the current DCLF Transport and Tariff model minimising the industry impact at a time when the overarching transmission access arrangements are being developed. A delay to implementation would prevent existing projects being provided a signal and could lead to inefficient over investment. By implementing a Local Charge for April 2009, a baseline is established and from which any consequential changes required by developments to the transmission access arrangements could be made.

The option to redefine the charging boundary so local generation assets are charged as connection assets was raised within the preconsultation and which received very little industry support. It again received no support when discussed within the Enabling Subgroup of the Transmission Access Review. There were considerable concerns that this option was a return to a deeper connection/use of system boundary for generation connections.

If a cost reflective wider locational signal was replaced with a flat wider charge, generation would not be exposed to the full transmission cost consequences of their siting decisions and therefore this may lead to an inefficient combined cost for generation and transmission. In addition, it appears inconsistent to implement greater cost reflectivity for local assets, whilst simultaneous removing the locational signal for wider infrastructure.

A design variation signal must be cost reflective of infrastructure asset savings and it is hard to see how a signal based on the availability of a circuit rather than the cost of the circuit would achieve this.

National Grid does not agree that this proposal represents a 'piecemeal' approach but rather a necessary change which is entirely consistent with our Transmission Licence obligation to keep the Charging Methodology under constant review for the purpose of ensuring it meets the relevant objectives.

**Specific treatment of generation connections (Option A)**

Of the respondents who preferred the Specific Treatment of Generation Connections one advantage stated by several respondents was its simplicity and transparency. Specifically one respondent also stated that the approach had the advantage of the least impact on the industry. Another stated it is easy to understand, a reasonable reflection of the cost of connection, consistent with 'Plugs' and works for both simple and complex investments and that the use of marginal costs is correct as opposed to an asset based charge.

Two responses stated that two classes of connections were created; those at MITS nodes and those not, which was discriminatory. The respondents stated that the Charging Methodology Relevant Objectives are not better met as Option A is not simple, transparent or predictable.

One respondent preferred the approach as being more cost reflective. Another respondent stated that local assets were robustly identified although use of the DCLF model would introduce uncertainty and unpredictability. A further respondent supported Option A as it is likely to produce stable long term tariffs being based on physical assets.

A respondent supported the local charge and option A as it aims to reflect the cost of the actual local assets and generally agreed with the points raised in the consultation, although stated that the approach does have a number of limitations. To cover such limitations, a mechanism was suggested where the generator and National Grid could bilaterally agree an alternative MITS node or local assets for scenarios where a generic approach does not wholly identify all local assets, subject to Ofgem agreement.

A respondent who preferred Option A believes its transparency will help small generation projects to connect which is important at a time when many such connection applications are expected.

Several respondents preferred Option A on a 'least worse' basis as it is more cost reflective than Option B. Two such respondents suggested improvements to Option A including the application of TO specific expansion factors, as applied in Option B, and connection specific local security factors to be calculated for each of the 25 specific generators without single circuit connections, so as to take account of partial redundancy. The respondent suggested calculating the local security factor using a ratio of local circuits capacity and generator export limit.

**National Grid's response**
National Grid agrees that whilst both approaches provide a cost reflective signal, the Specific Treatment of Generation Connections (Option A) has the advantage of being simple, transparent and can be implemented with minimal impact at a time of significant industry change.

The SQSS states that design variations are only permitted for assets that will not increase costs or affect the standard of security for other Users. Consequently, generation connected directly to a MITS node will not be able to determine the connection standard of the adjacent circuits and therefore the Use of System charge for such Users can be calculated through the wider TNUoS zonal average charge. Generation connected to non-MITS nodes are subject to more cost specific circuit Local Charges for transmission to the next, adjacent MITS nodes in order to ensure they are reflective of the cost implications of any design variation decisions. Applying a more cost specific charge for local circuit flow as opposed to the move averaged wider charge is not undue discrimination as it reflects the cost of supplying the service, namely the local circuit, to the User.

National Grid has a Transmission Licence obligation to make modifications to its Charging Methodology so as to better achieve the Relevant Objectives. In addition, National Grid has a number of further charging objectives which include clarity and transparency of methodology, accurate and stable charges and charging on incremental costs. Whilst National Grid agrees that splitting the locational TNUoS signal into a wider and a local component might marginally increase the complexity and lower the transparency of the charge, National Grid believes that this is proportionate to the fundamental issue that it seeks to address. The local and wider components will be available from an updated version of the DCLF model and published within the Statement of the Use of System Charges.

National Grid believes that a generic charging methodology should be applied in all instances, with the minimal amount of interpretation. National Grid would be concerned about a process by which a User could bilaterally negotiate exceptions to the generic averaging approach. Whilst this may bring some advantages in terms of cost reflectivity in certain circumstances, this would be outweighted by the adverse impacts of a reduction in the transparency and predictability of charges.

Within the Consultation, the Local Expansion Factors applied within Option A, are calculated from GB average costs provided across both TOs that construct 132kV OHLs. Under Option B, the TO specific Local Expansion Factors use the same base costs but include an uprating factor as currently applied to take into account the proportion of OHL that is likely to be uprated and operated to a higher voltage. OHL uprating is performed in order to increase transmission capacity using existing routes. This uprating factor approach avoids having to identify and track the specific circuits that are uprated. Such an uprating factor is not applied under Option A to the Local Expansion Factors, as such an averaging approach would significantly reduce the cost reflectivity of the design variation signal and it is highly unlikely that such local generation connection circuits would be uprated. The wider circuits are uprated in order to increase the bulk transfer capability between interconnected parts of the MITS.

Generation that retains the ability to export power after the loss of any local circuit inherently has a multiple circuit connection and is subject to a local security factor of 1.8, the GB Locational Security Factor average. Only a double circuit spur connection with two identical circuits will have a security factor of exactly 2.0, with the difference explained by factors such as circuits providing security for a multiple number of other circuits. For example, consider three parallel circuits, where the loss of one circuit would result in a 50% increase in power flow along the remaining, giving a security factor of 1.5. National Grid therefore believes that the application of a GB Locational Security Factor average of 1.8 for all multiple circuit connections is appropriate and sufficiently accurate. The calculation of nodal specific Security Factors is the approach taken under Option B which was rejected by the majority of respondents.

A specific subset of multiple circuit connections are partial redundancy design variations which are connected to the MITS network with multiple local circuits although the circuits do not have sufficient capacity to allow full generation export following a local circuit outage. National Grid agrees that if a User requests a design variation connection with partial redundancy, accepts the associated access restrictions and this leads to asset investment savings then an economic signal should be provided.

The straight forward ratio of local circuit capacity and generator export limit, as suggested by the respondent, can not be implemented on this simple basis to provide the correct signal. Firstly, determining the relevant capacity of the local circuits depends on a number of factors, for example the rating of OHLs is significantly affected by season and where multiple local circuits exist as parallel paths a more complicated treatment is required. Generator export limits for partial redundancy design variations are typically not specifically quantified in commercial agreements, such as the Bilateral Connection Agreement, to allow the System Operator to take specific real time conditions into account to minimise the restriction on the generator.

A robust and cost reflective solution should be developed that is not only suitable for the small number of existing generators that have a degree of partial redundancy but also for the significant number of transmission connected offshore generators expected to connection in the future with such connections. National Grid believes such a solution may need to take into account average or minimum circuit ratings and might factor the expected frequency, duration and magnitude of export restrictions and as such is a significant development from the existing Charging Methodology and full industry engagement and consultation is key, before enduring partial redundancy specific adjustments are proposed.

**Local Charge Cost Reflectivity**

Several respondents stated that cost reflectivity is increased with the introduction of a Local Charge. The sole respondent who supported the implementation of either option but preferred option B stated that whilst the methodology was simple, transparent and more cost reflective than the existing Charging Methodology, the assumptions required under Option A lessen the cost reflectivity of the proposed Local Charge.

One respondent stated that in order to ensure that Users opt for a design variation where it is economic and efficient to do so, the charge must be cost reflective of the capital costs involved, so avoided transmission investment can be compared to the lost opportunity cost for the generator. Several similar responses identified that the tariff differential produced by these proposals is broadly equal to that produced under

GB ECM-06 to which the Authority had concerns that the proposed modification would be insufficient to incentivise generators that opt for a design variation.

One respondent stated that the concept of splitting local and wider charges and attempting to target actual infrastructure cost savings may not sit well together. The respondent went on to suggest that either an alternative means of reflecting the savings and/or even for transmission charging as a whole may be more appropriate. The respondent continued that the cost variance in net generation recovery between the two Local Charging options was significant and therefore makes a defence of either method difficult on cost reflectivity grounds. The same respondent believed National Grid's charging methodology allocates costs according to which signals it chooses to amplify and which it chooses to socialise, which is difficult to view subjectively when many subjective assumptions and notional choices are involved that have significant impacts on individual parties.

**National Grid's response**

The use of simple local security factors is a balance between cost reflectivity and simplicity/ predictability, which will facilitate competition by providing a clear and stable signal to the User which reflects the implication of connection decisions.

In December 2007, National Grid wrote to the Authority[3] describing why it is essential that a design variation signal must be calculated on the same basis as the Use of System Charge. If the charge and discount are determined on a different basis, for example if the discount was determined on a sharper basis, a perverse incentive would exist to locate remotely from the transmission network, with a net effect of lowering overall charges, socialising costs across all Users.

National Grid agrees that providing a User with a cost reflective signal will in turn allow a comparison of the infrastructure asset savings against their valuation of the additional access that a fully compliant connection would give, ensuring the most efficient and economic connection is constructed.

In some instances the single/ double circuit Local Charge differential will not fully reflect the actual capital cost savings. The significant contributing factors to this aspect are:

1. OHL and substation local charges are based on the capacity booked rather than capacity installed
2. The use of average expansion factors
3. The local security factor for non-single circuit connections is assumed to be equal to the average GB Locational Security Factor i.e. 1.8.

In order to increase the cost reflectivity further, it would be necessary to change the basis on which the local charge is calculated, for example, generation connected by a spur would be exposed to the total cost of the spur circuit installed by the TO, independent of the size of the generator. National Grid believes this would have a significant detrimental effect, introducing a barrier to market entry and significantly decreasing the predictability of tariffs, with costs only determined upon completion of construction.

[3] http://www.nationalgrid.com/NR/rdonlyres/FBC9DAE1-C4D7-4FCA-AE1F-59F4C3520B9A/22249/NationalGridDesignVariationDiscountletter.pdf

National Grid believes that splitting local and wider assets is wholly compatible with producing a cost reflective signal for design variation connections. Such an approach permits a more specific cost reflective charge for use of the local network whilst keeping the benefits of zonal charging and averaging for the highly interconnected wider network.

Under Option B the more specific expansion factor for 132kV OHL are applied to both wider and local circuit flow rather than just to the local circuits as under Option A. This results in a different total recovery from the locational component of TNUoS and therefore produces the different residual recovery amounts as described by one respondent.

National Grid has a Charging Methodology objective to set out charges on a basis of incremental costs rather than average costs, so as to promote the optimal use and investment in the transmission system. Consequently the costs of investment that a User can have a direct and measurable effect upon, such as location or connection security, should be reflected on the User whereas other costs such as historic investment is funded on an average basis.

**Local Expansion Factors**

One respondent agreed that the local expansion factor should be more specific and reflect the actual connection cost rather than just be based on a single average expansion factor, although concern over potential volatility was expressed. The respondent remained unconvinced that RPI is an appropriate inflation factor for Local Expansion Factors, although no alternative was given.

Another respondent questioned whether Local Expansion Factors for 132kV OHL are based upon sample sizes that are large enough to be representative of actual costs in the majority of situations. It was suggested that National Grid make sufficient data available to Users to provide comfort that expansion factors and substation costs have been calculated on a consistent and verifiable manner.

**National Grid's response**

The Local Expansion Factors proposed are a balance between cost reflectivity, by the replacement of a single 132kV OHL expansion factor with four, and stability, simplicity and predictability. Although expansion factors calculated from actual circuit construction costs would inherently be highly cost reflective, there would be associated issues such as predictability and determining a cost for existing circuits. The Local Expansion Factors are not determined from a sample of actual projects but are calculated from average generic cost data submitted from all transmission Owners on the 18 feasible conductor/ tower constructions used for 132kV OHLs. The substation local charge component is derived from the costing of six generic connection designs from all three TOs.

Within the current Charging Methodology the Expansion Constant, the base £/MWkm cost for 400kV OHLs, is determined from data gathered from all TOs and then annually inflated by RPI during the Price Control Period. For the avoidance of doubt, Expansion Factors remain constant and will not be inflated as the final tariff will be inherently adjusted by the Expansion Constant.

**MITS node definition**

Two respondents stated that a clear rationale for the MITS node definition given needs to be presented. One respondent stated that the definition given is not consistent with that in the Grid Code, is not robust and can't be applied consistently, which makes charges unpredictable and volatile.

A further respondent believes it is unclear how existing and prospective generation projects will assess Local Charges as the network changes. Another respondent suggested that National Grid should produce a geographic map of the location of the MITS nodes which may aid the judgement of how far prospective projects may be from the MITS.

**National Grid's response**
The generation local charge covers the incremental investment made to the transmission network in order to connect generators into the interconnected network. The MITS node definition was aimed at identifying local assets that exist to connect generation only and the MITS node criteria were developed by examination of existing and current projects and of the local investment that was triggered upon their connection. The MITS nodes are required with or without the connection of the generator; the GSPs to supply demand and the nodes with more than four transmission circuits as a bussing point, therefore it would not be appropriate to target their costs as local generation costs. In addition, the proposed boundary identifies the typical point or boundary up to which a User may influence its connection design through design variation, under SQSS design variation criteria.

Under the MITS definition proposed, only the construction of additional Grid Supply Points or transmission circuits would change a node's MITS status and therefore changes will be infrequent. The definition criteria are simple, clear and unambiguous and the DCLF model is to be updated so as to identify and quantify the local circuit flow making it highly predictable and robust.

New and future Users will continue to be able to calculate TNUoS tariffs (both local and wider components) with a copy of the Transport and Tariff model which is made publicly available along with an associated guidance note. National Grid regularly holds Charging Methodology tutorials in addition to providing ad-hoc bilateral support.

The Local Charge breakdown to be published within the annual Statement of Use of System Charges will confirm whether a User is directly connected to a MITS node and the DCLF model will show which are the adjacent MITS nodes for those generators that are connect to a non-MITS node.

The term Main Interconnected Transmission System is currently not defined under the Grid Code.

**Distance to zonal hub (Option B)**
One respondent who supported the Distance to Zonal Hub approach for calculating the Local Charge, stated that it was based less on simplified assumptions and did not require technical interpretation, therefore it is more targeted and cost reflective and has acceptable tariff stability. Another respondent stated that the approach has some merit but is relatively unpredictable and opaque and may not be the appropriate balance between stability and cost reflectivity, with a significant change to baseline tariffs.

One respondent, who did not support implementing either option, stated that the division of local and wider assets is especially notional under Option B, which the respondent also believed was too complex, unpredictable, difficult to replicate and could suffer from volatility. It was believed that the problems associated with applying different expansion factors to local and wider circuits has led to stretching the 132kV network.

The majority of respondents did not support Option B and stated it was arbitrary/ conceptual, volatile, complex, that it reduces transparency and introduced TNUoS charging for sub 100MW BEGA connections. One respondent stated the approach would disincentivise new generation to connect. Another respondent believes that it does not solve the fundamental issue of Users being perversely incentivised to choose inefficient network investment.

A respondent stated that the contour shown in Appendix 8 appears to meander through and outside the TNUoS zone. Another respondent who did not support Option B, stated that an assumption within SECULF is that the transmission network is built to the same security standard although areas where investment has been lower, for economic reasons or derogations, the security factors calculated are in fact higher. The respondent continued that changes to zonal hub or zonal boundaries can change the Local Charge although there has been no change to physical assets.

**National Grid’s response**

National Grid agrees that the Distance to Zonal Hub approach reduces the requirement for technical interpretation and simplified assumptions. The requirement to use a secured load flow model to calculate TNUoS charges does increase complexity and under this approach, tariffs are subject to change due to TNUoS charging boundary changes or the connection of generation near the zonal hub.

By applying sharper expansion factors to both wider and local 132kV OHL circuit flows, the network is lengthened, or stretched, representing the more specific cost allocation to those circuits.

For the avoidance of doubt, under the Distance to Zonal Hub option, TNUoS will continue only to be paid by BEGA connected embedded generation projects that are greater than 100MW in size.

Option B produces a Local Charge tariff that contains a cost reflective signal that reflects the local asset investment required by each specific connection allowing a User to determine their economic and efficient level of connection security. National Grid believes that if the provision of a cost reflective signal suggests that there is not an economic case for a specific project then that is the correct and efficient result.

**Secured Loadflow Model (SECULF)**

One respondent stated that use of the SECULF model handles security assets more accurately than the simplified assumptions under Option A. Another respondent did not support the use of the Seculf model, stating that it is complex, removes transparency and reliability.

One respondent who did not support Option B, stated that Seculf was developed to be used in the calculation of zonal prices where the simplified assumptions made do not distort individual charges. However, if the model is used at a nodal level it is believed the averaging assumptions used will significantly distort the resultant charges. The respondent gave an example of how the model scales down total generation so as to match winter peak demand. Such an assumption could lead to the reversal of flow along a circuit which could have a significant effect to the marginal km cost at a nodal level.

**National Grid's response**
National Grid agrees that the use of the Secured Loadflow model, inherently calculates the marginal cost associated with post fault power flows, which is consistent with how decisions are made for network reinforcement. That withstanding, National Grid concurs that the concept behind such charging is a degree more complex and makes a User more reliant on using the model to assess the implications of baseline changes.

National Grid believes that whilst nodal charges based on a secured model may more accurately reflect the cost implications associated with location, post fault security and investment from customer choice than an approach with averaging assumptions, there is a trade off with a higher sensitivity or volatility of the charges.

**Substation Local Charge component and the connection/ infrastructure asset boundary**
Three respondents provided comment specifically on the local charge substation component. One respondent supported the provision of a signal for the non-locational element of cost savings associated with design variations but commented that this puts demand and generation on a different charging basis, with generation being exposed to a sharper locational charge. Another respondent believed that sufficient rationale for a substation Local Charge had not been found and that generation and demand substation assets should continue to be charged by the same methodology. The respondent stated that the sole justification for the substation Local Charge is to provide a signal for design variation connection and did not support providing a signal for connecting below the minimum connection standards as set out in the SQSS.

One respondent stated that there may be an issue with the definition of the existing charging boundary between connection and infrastructure assets. The respondent's existing connection is made via a single circuit teed connection and consequently the non locational assets are charged as connection assets, although it was their understanding that if a double circuit connection has been constructed the substation assets would have been classed shared user assets and the cost would have been recovered as infrastructure through TNUoS. Such arrangements were described as inequitable as the total charge for the less secure charge would be greater. In addition, if this has not been reflected within the calculation of substation Local Charges then they will not be accurate.

**National Grid's response**
National Grid agrees that the proposals do change the basis on which the locational signal for generation and that for demand is charged but does not believe this to be significant. Generation and demand are already charged with a differing signal, for example the infrastructure/ connection asset boundary for a Grid Supply Point is defined at a different point than for a generation connection.

In order to ensure the full cost signals associated with connection investment decisions, both the circuit and substation costs must be reflected upon a User. A subset of design variation connections, will have little or no distance rated investment, for example a down dropper connection to an existing transmission line and therefore if the non-locational asset savings are not reflected onto the User through a substation local charge, the efficient and economic investment decision will not be reached.

National Grid believes it is appropriate to provide a signal for connecting below the minimum standard of SQSS compliance, as a condition of the User's request for a design variation is the acceptance of partially non-firm access restrictions. Interruption Payments are not given for loss of access stemming from the non compliant assets. Through these arrangements the User accepts all commercial risk and therefore other Users are held harmless and it is reasonable that any infrastructure savings associated with the lower standard of connection should be reflected on the User.

The Statement of Connection Charging Methodology describes how a teed connection is deemed as sole user assets (up to the HV isolator) irrespective of whether single or double circuit. Sole user assets are charged as connection assets and therefore, a double circuit teed connection will have a higher connection charge reflecting the higher asset requirement. An exception may occur where the TO believes multiple users will connect at the site and the efficient and economic design is a substation at the connection node. In which case the substation and teed circuits would be shared use and charged as infrastructure.

**Implementation and Consultation Timescales**

Three respondents objected that the consultation period was too short and that the Transmission Licence would have allowed for greater than 28 days and consequently it is vital that the Authority carries out a Regulatory Impact Assessment. Another two respondents believed implementation at this point would lead to the requirement for further iterations as the Transmission Access Review was developed, one stated that the arrangements had not been properly tested and the other stated that a 2010 implementation would allow parties to take account of the resultant changes to their contract positions.

One respondent stated that although option A could be implemented for 2009, option B is likely to be more flexible and cost reflective with the TAR proposals. Another respondent stated that immediate implementation of Option A, will have least impact at a time of uncertainty for generation, through TAR.

**National Grid's response**

Following the previous stages of development of the original design variation discount charging arrangements[4] during 2006 and 2007, the Local Charging preconsultation was published in March 2008 to assess various high level approaches and ensure full industry engagement. The Local Charging arrangements have been developed in conjunction with the Enabling Subgroup of the Transmission Access Review, over nine meetings since May 2008. The Enabling Subgroup has representations across the industry and all material presented and minutes have been published on the National Grid TAR website[5].

Fourteen responses were received by the end of the 28 day consultation period for GBECM 11. That withstanding, National Grid has a licence obligation to provide final TNUoS charges two months before the start of the charging year and voluntarily produces indicative tariffs one month before then. In order for the Conclusion Report to be submitted in sufficient time for indicative charges to be processed that take into account the Authority decision, a longer consultation period was not feasible

[4] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

[5] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/workingstandinggroups/wg161-166/

assuming a Regulatory Impact Assessment. National Grid believes it important for a single set of indicative charges to be produced so as to minimise impact and increase transparency of the charging modification, giving certainty to projects currently making decisions relating to asset investment.

The Local Charge has been developed alongside all the TAR charging and access solutions to ensure compatibility and avoid consequential work although further consultation could be required. Delaying implementation will not only further increase the number and complexity of proposals that the industry and Authority will have to simultaneously consider but National Grid has a Transmission Licence obligation to better meet the Relevant Objectives and it is not clear that this would be achieved with additional delay.

National Grid agrees that Option A should be implemented for 1 April 2009, minimising impact on the industry. Consequential changes might be required next year as part of the Transmission Access Review.

**Provision of further information**
A respondent stated that National Grid should provide an estimate of how much additional renewable generation is expected to connect as a result of these arrangements. Another two respondents stated that Offshore Generation is an extreme example of a local connection and without clarity of how Offshore charging will be calculated it is not possible to assess this ‘acid test’.

**National Grid’s response**
The Local Charging modification has been progressed as part of the role of the TAR Enabling Sub Group and although it is expected that the provision of improved TNUoS cost reflectivity for single circuit connections will immediately facilitate connection of additional single circuit renewable connections, the further benefits are expected when the remainder of the wider TAR arrangements are implemented and such connections are able to connect via Local Only connections, of which this modification is an essential component.

National Grid agrees that the scale and range of expected offshore generator connections require an effective Local Charge. A second offshore consultation is anticipated to be published shortly that will specifically look at the applicability of the onshore Charging Methodology and Local Charging to the offshore environment. Although the principle of applying the onshore methodology is applied where appropriate, some additional unique additions to the methodology will be required, such as those associated with funding the Offshore Transmission Owner revenue. Consequently, National Grid does not believe the implementation of Local Charging should be delayed to order to coordinate its implementation alongside the offshore charging arrangements.

## 4 Changes to the proposal in light of representations made

No changes to the proposals have been made.

## 5 How the proposed modification better meets the relevant licence objectives

National Grid’s proposal to modify the Statement of the Use of System Charging Methodology better meets the Relevant Objectives in Licence Conditions C5 5(b) and C5 5(c). Namely to ensure National Grid applies charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses and properly takes account of the developments in transmission licensees' transmission businesses.

**C5 5(b) Cost Reflectivity**
Improves the cost reflectivity of charging for assets local to generation connections by:

- Applying more specific local expansion factors and local security factors for local circuit flow
- Implementing a local substation tariff, which charges a User for the primary substation assets at the generation connection substation using generic costs based on connection voltage, substation redundancy and total export capacity of generation connected

**C5 5(c) Developments in Transmission Business**
Takes account of development in the TLs' transmission business:

- Provides a signal to generators choosing between differing levels of infrastructure investment through SQSS variation to connection design which reflecting the infrastructure investment avoided. Allows the identification of the economic and efficient connection design whereby the User assesses its value of access against the cost of infrastructure investment. Vital for the forthcoming connection of the high volume of remote, renewable projects.

## 6 Timetable for implementation

Subject to the Authority's power to veto this modification proposal, National Grid intends to make the proposed changes to the Transmission Network Use of System Charging Methodology for implementation on 1 April, 2009.

# Appendix 1 - Proposed drafting of the Statement of the Use of System Charging Methodology for the Specific Treatment of Generation Connections

## Chapter 2: Derivation of the Transmission Network Use of System Tariff

*Replaces existing paragraph 2.3*

2.3 The transport model requires a set of inputs representative of peak conditions on the transmission system:

- Nodal generation information
- Nodal demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The ratio of each of 132kV overhead line, 132kV cable, 275kV overhead line, 275kV cable and 400kV cable to 400kV overhead line costs to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generators local charge.
- Identification of a reference node

*Replaces existing paragraph 2.8*

2.8 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) cabled routes and overhead line routes, (ii) 132kV and 275kV routes, (iii) 275kV routes and 400kV routes, and (iv), uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically 400kV cable, 275kV overhead line, 275kV cable, 132kV overhead line and 132kV cable) is more expensive than for 400kV overhead line. For the wider tariff, this is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. Alternative 132kV expansion factors for local circuits are used to calculate the local tariff.

*Replaces existing paragraphs 2.12 - 2.46*

2.12 Using a similar methodology a generators local tariff is calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake at the reference node. The local tariff is calculated from the increase or decrease in MWkm for any circuits identified as local assets.

2.13 An example is contained in **Appendix TN-1: Transport Model Example.**

### Calculation of local nodal marginal km

2.14 In order to ensure assets local to generation are charged in a cost reflective manner, a generation Local Tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

2.15 Main Interconnected Transmission System (MITS) nodes are defined as:

- A Grid Supply Point connection with 2 or more transmission circuits connecting at the site or;
- More than 4 transmission circuits connecting at the site.

Where a Grid Supply Point is defined as a point of supply from the GB Transmission system to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the GB transmission system between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

2.16 Generators directly connected to a MITS node will not have a circuit based Local Tariff.

2.17 Generators not connected to a MITS node will have a Local Tariff derived from the marginal flow along the transmission circuits connecting it to all adjacent MITS nodes. The local tariff will be calculated using local circuit expansion factors.

**Calculation of zonal marginal km**

2.18 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 2.21. The number of generation zones set for 2008/9 is 20.

2.19 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

2.20 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity. Firstly the zonal marginal km for generation is calculated as:

$$WNMkm_j = \frac{\left(NMkm_j - NLMkm_j^{\ W}\right) * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi} = \sum_{j \in Gi} WNMkm_j$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| NMkm | = | Nodal marginal km from transport model |
| WNMkm | = | Weighted nodal marginal km |
| ZMkm | = | Zonal Marginal km |
| Gen | = | Nodal Generation from the transport model |
| $NLMkm^{W}$ | = | Nodal marginal km along local circuits calculated using wider circuit expansion factors |

2.21 The zonal marginal km for demand zones are calculated as follows:

$$WNMkm_j = \frac{-1 * NMkm_j * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di} = \sum_{j \in Di} WNMkm_j$$

Where

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Demand from transport model |

2.22 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of National Grid that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zones should contain relevant nodes whose marginal costs (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

2.23 The process behind the criteria in 2.21 is driven by initially applying the nodal marginal costs from the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. For the avoidance of doubt, generation nodes will be zoned discounting the magnitude of the circuit element of the Local Charge. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs for guidance.

2.24 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by National Grid to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, National Grid determines and uses the one that best reflects the physical system boundaries.

2.25 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff**

2.26 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

**The Expansion Constant**

2.27 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

2.28 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 2.49, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 2.60.

2.29 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents National Grid's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

2.30 For each circuit type and voltage an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the circuit expansion factors discussed in 2.40. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

2.31 The table below shows the first stage in calculating the expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| **400kV OHL expansion constant calculation** | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | £(000)/km | Circuit km* | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

2.32 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

2.33 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the National Grid regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

2.34 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2008/9 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

2.35 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | |
|---|---|
| | **Ave £/MWkm** |
| **OHL** | 114.160 |
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

2.36 This process is carried out for each voltage, along with other adjustments to take account of upgrade options, see 2.35, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the expansion factors.

2.37 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in National Grid's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2008/9 is 10.289.

**Wider Circuit Expansion Factors**

2.38 Base expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

2.39 In calculating the cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

2.40 The 132kV circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

2.41 The 275kV circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

2.42 The 400kV expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

2.43 The TO specific circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV cable factor: | 22.39 |
| 275kV cable factor: | 22.39 |
| 132kV cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV cable factor: | 22.39 |
| 275kV cable factor: | 22.39 |
| 132kV cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**The Local Circuit Expansion Factors**

2.44 The Local Circuit Tariff is calculated using Local Circuit Expansion Factors. These Expansion Factors are calculated using the same methodology as wider Expansion Factor but without taking into account the proportion of circuit kms that are planned to be uprated.

2.45 In addition, the 132kV overhead line circuit expansion factor is sub divided into four more specific expansion factors, This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV cable factor: | 22.39 |
| 275kV cable factor: | 22.39 |
| 132kV cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single;<200MVA): | 10.00 |
| 132kV line factor (double;<200MVA) : | 8.32 |
| 132kV line factor (single;>=200MVA): | 7.13 |
| 132kV line factor (double;>=200MVA): | 4.42 |

**The Locational Security Factor**

2.46 The locational security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

2.47 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[6].

2.48 The locational security factor derived for 2008/9 is 1.8 and is based on an average from a number of studies conducted by National Grid to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

2.49 Local Security Factors are generator specific and are calculated for generation that has a local tariff. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a Local Security Factor of 1.0 is applied. For generation with circuit redundancy, a Local Security Factor is applied that is equal to the Locational Security Factor, currently 1.8.

**Initial Transport Tariff**

2.50 First an Initial Transport Tariff (ITT) must be calculated. For Generation the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor to give the initial transport tariff:

$$ZMkm_{Gi} \times EC \times LSF = ITT_{Gi}$$

Where

| | | |
|---|---|---|
| $ZMkm_{Gi}$ | = | Zonal Marginal km for each generation zone |
| EC | = | Expansion Constant |
| LSF | = | Locational Security Factor |
| $ITT_{Gi}$ | = | Initial Transport Tariff (£/MW) for each generation zone |

2.51 Similarly, for demand the zonal marginal km (ZMkm) are simply multiplied by the expansion constant and the locational security factor to give the initial transport tariff:

$$ZMkm_{Di} \times EC \times LSF = ITT_{Di}$$

Where

[6] http://www.nationalgrid.com/uk/Electricity/Charges/

| | | |
|---|---|---|
| $ZMkm_{Di}$ | = | Zonal Marginal km for each demand zone |
| EC | = | Expansion Constant |
| LSF | = | Locational Security Factor |
| $ITT_{Di}$ | = | Initial Transport Tariff (£/MW) for each demand zone |

2.52 The next step is to multiply these initial transport tariffs by the expected metered triad demand and generation capacity to gain an estimate of the initial revenue recovery. Both of these latter parameters are based on forecasts provided by Users and are confidential.

$$\sum_{Gi=1}^{21}\left(ITT_{Gi}\times G_{Gi}\right)=ITRR_G \quad \text{and} \quad \sum_{Di=1}^{14}\left(ITT_{Di}\times D_{Di}\right)=ITRR_D$$

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for demand |
| $D_{Di}$ | = | Total forecast Metered Triad Demand for each demand zone (based on confidential User forecasts) |

2.53 The next stage is to correct the Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained. This has been determined to be 27:73 by the Authority for generation and demand respectively. In order to achieve the 'correct' generation/demand revenue split, a single additive constant C is calculated which is then added to the total zonal marginal km, both for generation and demand as below:

$$\sum_{Gi=1}^{21}\left[\left(ZMkm_{Gi}+C\right)\times EC\times LSF\times G_{Gi}\right]=CTRR_G$$

$$\sum_{Di=1}^{14}\left[\left(ZMkm_{Di}-C\right)\times EC\times LSF\times D_{Di}\right]=CTRR_D$$

Where C is set such that

$$CTRR_D = p\left(CTRR_G + CTRR_D\right)$$

Where

| | | |
|---|---|---|
| CTRR | = | "Generation / Demand split" corrected transport revenue recovery |
| p | = | Proportion of revenue to be recovered from demand |
| C | = | "Generation /Demand split" Correction constant (in km) |

2.54 The above equations deliver corrected (£/MW) transport tariffs (CTT).

$$\left(ZMkm_{Gi} + C\right)\times EC \times LSF = CTT_{Gi}$$

$$(ZMkm_{Di} - C) \times EC \times LSF = CTT_{Di}$$

So that

$$\sum_{Gi=1}^{21}(CTT_{Gi} \times G_{Gi}) = CTRR_G \quad \text{and} \quad \sum_{Di=1}^{14}(CTT_{Di} \times D_{Di}) = CTRR_D$$

## Deriving the Final Local £/kW Tariff

### Local Circuit Tariff

2.55 Generation with a Local circuit tariff is calculated by multiplying the nodal marginal km along the local circuits by the expansion constant and the local security factor to give the Local circuit tariff:

$$NLMkm_{Gj}^{\ L} \times EC \times LocalSF = CLT_{Gi}$$

Where

$NLMkm_{Gi}^{L}$ = Nodal marginal km along local circuits using local circuit expansion factors.

EC = Expansion Constant

LocalSF = Local Security Factor

$CLT_{Gi}$ = Circuit Local Tariff (£/kW)

### Local Substation Tariff

2.56 All chargeable generation is subject to the Local Substation Tariff £/kW component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system.
(b) Sum of TEC at the generation substation– the combined TEC of all generation at the connecting substation
(c) Single Busbar/ double busbar connection – the level of redundancy at the generation substation ie a single busbar / single switch mesh connection or a redundancy connection which includes double Busbar and mesh sub station designs.

2.57 Using the previous cost determing factors, the corresponding £/kW tariffs will be applied:

| TEC Connecting at Node | Single/Double busbar substation configuration | Substation Local Tariff (£/kW) | | |
|---|---|---|---|---|
| | | 132kV | 275kV | 400kV |
| **<1320MW** | **Single** | **0.129** | **0.078** | **0.063** |
| **<1320MW** | **Double** | **0.291** | **0.186** | **0.150** |
| **>1320MW** | **Single** | **-** | **0.249** | **0.201** |
| **>1320MW** | **Double** | **-** | **0.404** | **0.325** |

2.58 The process for calculating Local Substation Tariffs will carried out for the first year of the price control and will subsequently be indexed by RPIfor each subsequent year of the price control period.

2.59 The total Local Tariff (£/kW) is calculated as the sum of the circuit and substation components:

$$\mathrm{LT}_{\mathrm{Gi}} = CLT_{Gi} + SLT_{Gi}$$

Where

| | | |
|---|---|---|
| $LT_{Gi}$ | = | Local Tariff (£/kW) |
| $SLT_{Gi}$ | = | Substation Local Tariff (£/kW) |

2.60 Total Local Charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * Gen_j$$

Where

$LCRR_G$ = Local Charge Revenue Recovery

*Existing paragraphs 2.47 – 2.59 to be renumbered to 2.61 – 2.73*

*Replaces existing paragraph 2.49 and will renumbered 2.63*

2.63 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 corrected transport tariffs so that the correct generation/ demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times PTRR) - CTRR_D}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times PTRR] - CTRR_G - LCRR_G}{\sum_{Gi=1}^{21} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

*Replaces existing paragraph 2.50 and will renumbered 2.64*

2.64 The final Transmission Network Use of System tariff (TNUoS) can now be calculated as the sum of the corrected wider transport tariff, the non-locational residual tariff and the local tariff

$$FT_{Gi} = \frac{CTT_{Gi} + RT_G + LT_{Gi}}{1000} \quad \text{and} \quad FT_{Di} = \frac{CTT_{Di} + RT_D}{1000}$$

Where
FT = Final TNUoS Tariff expressed in £/kW

## Chapter 5: Generation charges

*Replaces the existing paragraphs 5.5* – 5.17

Generation with positive tariffs

5.5 The Chargeable Capacity for Power Stations with positive generation tariffs is the highest Transmission Entry Capacity (TEC) applicable to that Power Station for that Financial Year. A Power Station should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity, STTEC). For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

5.6 The short-term chargeable capacity for Power Stations situated with positive generation tariffs is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as appropriate.

5.7 The Chargeable Capacity for an Interconnector with positive generation tariffs is the highest TEC applicable to that Interconnector for that Financial Year. An Interconnector should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity).

5.8 The short-term chargeable capacity for an Interconnector with positive generation tariffs is any approved STTEC or LDTEC applicable to that Interconnector during a valid STTEC Period or LDTEC Period, as appropriate.

5.9 For Power Stations and Interconnectors, the short term chargeable capacity for LDTEC with positive generation tariffs referred to in Paragraphs 5.6 and 5.8 will be the capacity purchased either on a profiled firm[7] or indicative[8] basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second of 50MW. Further examples are provided on Pages 35 and 36 of this document.

[7] where an LDTEC Block Offer has been accepted (Profiled Block LDTEC) and a firm profile of capacity has been purchased.

[8] where an LDTEC Indicative Block Offer has been accepted (Indicative Profiled Block LDTEC) and a right to future additional capacity up to a requested level has been purchased, the availability of which will be notified on a weekly basis in accordance with the CUSC.

**<u>Negative Charging Zones</u>**

5.10 The Chargeable Capacity for Power Stations and Interconnectors <u>with negative generation</u> tariffs is the average of the capped metered volumes during the three settlement periods described in 5.11 below, for the Power Station (i.e. the sum of the metered volume of each BM Unit associated with Power Station in Appendix C of its Bilateral Agreement) or Interconnector. A Power Station or Interconnector should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity). If TEC is exceeded, the metered volumes would each be capped by the TEC for the Power Station or Interconnector applicable for that Financial Year. For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

5.11 The three settlement periods are those of the highest metered volumes for the Power Station or Interconnector and the two half hour settlement periods of the next highest metered volumes which are separated from the highest metered volumes and 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.

**<u>Example</u>**

If the highest TEC for a Power Station were **250MW** and the highest metered volumes and resulting capped metered volumes were as follows:

| Date | 19/11/08 | 13/12/08 | 06/02/09 |
|---|---|---|---|
| Highest Metered Volume in month (MW) | **245.5** | **250.3** | **251.4** |
| Capped Metered Volume (MW) | **245.5** | **250.0** | **250.0** |

Then, the chargeable Capacity for the Power Station would be:

$$\left(\frac{245.5 + 250 + 250}{3}\right) = \mathbf{248.5\ MW}$$

Note that in the example above, the Generator has exceeded its TEC on 13 December 2007 and 6 February 2008 and would therefore be in breach of the CUSC unless the generator had an approved STTEC or LDTEC value. (The STTEC and LDTEC charge for negative zones is currently set at zero).

5.12 The short-term chargeable capacity for Power Stations <u>with negative generation tariffs</u> is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as applicable.

5.13 The short-term chargeable capacity for Interconnectors with negative generation tariffs is any approved STTEC or LDTEC applicable to that Interconnector during a valid STTEC Period or LDTEC Period, as applicable.

5.14 For Power Stations and Interconnectors with negative generation tariffs, the short-term chargeable capacity for LDTEC referred to in Paragraphs 5.12 and 5.13 will be the capacity purchased either on a profiled firm or indicative basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second at 50MW.

5.15 As noted above, a negative LDTEC tariff is set to zero. Accordingly no payments will be made for use of LDTEC (in any of its forms) in these zones.

## Small Generators Charges

5.16 Eligible small generators' tariffs are subject to a discount of a designated sum defined by Licence Condition C13 as 25% of the combined residual charge for generation and demand. The calculation for small generators charges is not part of the methodology however, for information the designated sum is included in **The Statement of Use of System Charges.**

## Monthly Charges

5.17 Initial Transmission Network Use of System Generation Charges for each Financial Year will be based on the Power Station Transmission Entry Capacity (TEC) for each User as set out in their Bilateral Agreement. The charge is calculated taking the forecast Chargeable Capacity and multiplying it by the final generation tariff. This annual TNUoS generation charge is split evenly over the 12 months and charged on a monthly basis over the year. For positive final generation tariffs, if TEC increases during the charging year, the party will be liable for the additional charge incurred for the **full** year, which will be recovered uniformly across the remaining chargeable months in the relevant charging year (subject to Paragraph 5.18 below). An increase in monthly charges reflecting an increase in TEC during the charging year will result in interest being charged on the differential sum of the increased and previous TEC charge. The months liable for interest will be those preceding the TEC increase from April in year t. For negative final generation tariffs, any increase in TEC during the year will lead to a recalculation of the monthly charges for the remaining chargeable months of the relevant charging year. However, as TEC decreases do not become effective until the start of the financial year following approval, no recalculation is necessary in these cases. As a result, if TEC increases, monthly payments to the generator will increase accordingly.