nationalgrid

PRE-CONSULTATION DOCUMENT

GBECM-11

Charging Arrangements for Generator Local Assets

February 2008

Table of Contents

1. Executive Summary

In light of recent work on the charging arrangements for Security and Quality of Supply Standard design variations and the options being discussed as part of the Transmission Access Review to provide short-term access; this pre-consultation document identifies the main options available for modifying the charging arrangements to improve the cost-reflectivity of assets local to generation connections.

The options identified in this document are by no means exhaustive and National Grid welcomes industry views on further options. The document has been published on the National Grid charging website at the following address:

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

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.

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.

Before making a modification to the Use of System Charging or Connection Charging Methodology, National Grid is also required by the transmission licence to consult with CUSC Users on the proposed modification and allow them a period of not less than 28 days within which to make written representations.

The purpose of this document is to set out for pre-consultation the options available to modify the charging arrangements for assets local to generation connections, considering the relevant objectives and in particular the objective to set charges which reflect the costs incurred by the transmission licensees in their transmission businesses. We recognise that as well as changes to the charging methodologies, implementation of local asset charging will have some implications for other core industry documents; we welcome Industry thoughts on any directly consequential changes.

3. Background

The treatment of assets local to generation connections within the Transmission Network Use of System (TNUoS) methodology has been identified as requiring a more cost reflective approach to provide a sharper signal to generators through the development of two issues; charging arrangements for Security and Quality of Supply Standard (SQSS) design variation connections and the Transmission Access Review. These two issues are described below.

SQSS Design Variations
The 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. Without these arrangements, other customers would be exposed to additional operational (compensation) costs as a result of the single circuit connection, thus 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.

This represents a risk to customers that choose single circuit design variation connections, since the connection may be modified to a double circuit connection in the future for reasons which are largely beyond their control, albeit an identified contractual risk.

Prior to the implementation of the plugs ‘shallow’ Connection Charging Methodology on 1 April 2004, many of the assets associated with generation connections were classified as ‘connection assets’. Consequently, a customer choosing a lower standard of connection design had the capital savings directly reflected in lower 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, most of the assets for connecting generation have been reclassified as infrastructure and since such 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.

Progress to date

In November 2006 National Grid submitted to the Authority final proposals for a charging amendment (GBECM-06[1]) to address the problem around charging for design variation connections after preconsultation[2] and consultation[3] with the industry and discussion within the Transmission Charging Methodology Forum (TCMF) and Charging Issues Steering Group (CISG) forums. The proposals included a substation and a circuit discount to the TNUoS charge calculated using a generic formula derived from the Use of System charging methodology.

In February 2007, following a Regulatory Impact Assessment, the Authority issued a veto decision, as the Authority felt significant issues remained concerning the cost reflectivity of the proposed discount levels, in particular relating to the circuit discount element. National Grid was requested to further consider the modification and address the representations made to the Impact Assessment. It was suggested that the arrangements should better reflect the actual capital cost savings associated with building single circuits to provide a stronger signal to generators.

National Grid performed considerable work in this area in conjunction with substantial industry consultation. Further analysis of options to provide a better reflection of the cost saving was performed which revealed that if the discount per kilometre was larger than the charge per kilometre, then a perverse locational incentive was established to connect remotely which could trigger inefficient transmission investment.

Further analysis was also undertaken to investigate examples where the proposed circuit discount was not consistent with actual capital cost savings. This circuit discount was refined to include provisions for “tee” connections and connections with thermal rating restrictions previously not included in the proposals.

A consultation document (GBECM-09[4]) was issued to the industry on 2 November 2007 which covered a range of options for charging arrangements for the single circuit, substation and partial redundancy aspects of design variation connections. National Grid

[1] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/
[2] http://www.nationalgrid.com/NR/rdonlyres/8A0E0369-A358-4FBC-BAB7-9B1FC8A31512/9272/GBECM06SQSSDesignVariationpreconsultation.pdf
[3] http://www.nationalgrid.com/NR/rdonlyres/597EB9D5-DD49-4605-BBEC-388816C4416C/11930/GBECM06SQSSDesignVariationsConsultation.pdf
[4] See note 1.

supported the generic approach derived from the charging methodology, as it provided the most cost reflective discount that did not create an inappropriate locational signal.

Twelve responses[5] to the consultation were received from industry representatives and following review it became apparent respondents were broadly split into two groups: those who believe the proposals are broadly appropriate in that any discount must be consistent with how the original charge is calculated in order to avoid perverse incentives; and those that believe it is essential that any proposed discount must directly reflect the actual cost savings that result from a lower security connection and that the discounts proposed are simply not sufficient to influence a generator's decision and would lead to over investment in transmission infrastructure.

As described above, the discount arrangements that were proposed are calculated to be consistent with the charging methodology and, as a consequence, not fully cost reflective for local asset savings, as a result of several factors:

- The charge and discount were based upon the capacity booked Transmission Entry Capacity (TEC) rather than the assets installed
- The charge and generic discount were calculated from expansion factors, which are derived from average future costs weighted by historic use. The averages include circuits performing various functions and there is a significant cost variance between circuits for bulk transport of power and circuits for 'local' generation spurs, particularly at 132kV. Most relevant users with design variations are connected by circuits at 132kV.
- Both the charge and therefore discount for substation assets are socialised within the residual element of TNUoS.

Following the consultation, it became clear that it is not possible to achieve full cost reflectivity for local asset savings and avoid inappropriate locational signals as a discount must be consistent with how charges are calculated. Given this situation National Grid has broadened the scope of the initial issue to in order to determine and propose a more complete solution i.e. if the discount must be consistent with the charge then the charging arrangements need to be reviewed to allow for a more cost reflective discount.

National Grid continues to believe that average expansion factors remain appropriate for bulk transfer circuits within the main interconnected transmission system (MITS), and no justification was presented in the previous consultation responses seeking to review how such assets are charged. However, it has been shown that there may be significant benefit from treating local generator circuits in a different manner to MITS circuits. By broadening the scope of the initial issue to encompass the charge associated with local generator circuit assets it is possible to address the issues previously identified.

Given the concerns raised by respondents, National Grid decided not to submit any of the proposals consulted on during the previous charging consultation since these would not have provided an acceptable solution. Instead, National Grid initiated work on the enduring solution immediately.

Ofgem wrote to National Grid[6] providing support for such an approach and National Grid consequently initiated industry discussions on alternative approaches at the January 2008 Charging Issues Standing Group meeting. The detailed further analysis and

[5]The responses can be found on the National Grid Charging website at: http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/
[6] http://www.nationalgrid.com/NR/rdonlyres/B5D4E5E9-1903-443E-AD7F-56629AF5FD67/22250/OfgemSQSSDesignVariationResponseLetter.pdf

industry consultation required for such a significant change prohibited implementation from 1 April 2008. This preconsultation paper is intended to provide the industry with an opportunity to formally comment on the initial proposals before a formal consultation on the final proposals preceding submission of the conclusions report to the Authority in summer 2008. National Grid will discuss the results of this preconsultation at industry meetings to establish a wider industry meeting to establish wider views on any options presented.

Transmission Access Review
In July 2007, Ofgem and BERR published an open letter setting out the terms of reference for a wide scale Transmission Access Review (TAR), and have subsequently published a Call for Evidence document and an Interim Report. This review has given consideration to some indicative straw men, and has now moved on to more detailed analysis of key access “building blocks”. A number of potential solutions included in these straw men and building blocks, such as more flexible short-term access products and the ability for generators to share TEC within defined zones, would give generators access to the wider system without the provision of additional infrastructure.

It would therefore be inappropriate to levy an investment based charge on generators in such circumstances (although alternative charges, such as one based on operational costs for short-term products, may be appropriate). However, in order to use these products a local connection would still be required. As the costs of local and wider infrastructure are currently recovered through the single TNUoS charge, there would be a requirement to split TNUoS down into these constituent components. The ability to offer alternative access products enabling earlier and possibly more efficient access to the transmission system is therefore another important driver leading National Grid to consider charging arrangements for generators’ local infrastructure.

4. Option Assessment

The options presented are intended to improve the cost reflectively for the charging of assets local to generation connections. Such charging arrangements lack cost reflectivity as a result of several of the averaging approaches taken within the Charging Methodology that are described in section 3 above. Previous charging consultations concerning the charging arrangements for SQSS design variation connections have sought to provide a discount within TNUoS consistent with this averaged treatment and consequently a full cost reflective signal could not be achieved.

Several approaches to achieving a more specific treatment of assets local to generators are presented below. These are:

- **Specific treatment of generation assets**
  Local assets are identified, removed from the transport model and charged separately using specific expansion and security factors.
- **Specific treatment of distance to zonal hub**
  The marginal investment cost associated with a generator is separated into a cost from the generator to a zonal hub and a cost from the zonal hub to the market hub (reference node). Specific expansion and security factors are then applied to the calculation of the cost from the generator to the zonal hub.
- **Deepening of the use of system/connection asset charging boundary**
  The charging boundary is redefined so local generation assets are charged as connection assets. The full cost of installed substation and circuit assets are charged to the user with a methodology used to apportion shared assets.

The first two options maintain the principle of charging for generator circuit local assets as infrastructure within TNUoS and both could be applied in conjunction with an option to introduce a substation local asset charge as discussed below.

4.1 Specific treatment for generation assets

Within this option all infrastructure circuit assets are classified as either generator local circuit assets that connect generation or wider circuit infrastructure for bulk transportation of electricity. Generator local circuit assets are defined here as those infrastructure circuit assets that would not be required without the generation connection.

The local assets would be removed from the transport model and consequently the generator would be modelled as directly connected at the nearest MITS node. This allows a charge for "wider" circuit assets to be determined from the existing transport model. A charge for the "local" circuit assets would then be determined with the use of specific expansion factors and security factors. These more specific factors may be calculated from local data rather than GB averages.

Re-referencing, which ensures 27% of the revenue collected from the locational element of the TNUoS charge comes from generation, would be performed using the combined total of "local" and "wider" circuit charges. This also ensures that the total revenue recovered from the generation locational element remains unchanged by this option. Depending on the definition of this option, generation connected directly onto the MITS may not be subject to any local circuit asset charge.

Within the definition of the specific treatment of generation assets option, there are four areas for which various sub-options have been identified. National Grid invites views on each of the sub-options described below.

4.1.1 Generator only vs. marginal investment

The generation local asset charge is intended to include the asset investment that is solely made as a direct consequence of the connection of a generator. This could be defined using either of the techniques described below.

- **Generator only**

  Within this option only those circuits that would not have been built if generation was not connected would be classified as generation local assets. This defines a test for identifying local assets although such an approach will not factor in the full local impact of the generation connection in all instances.

  For example, where generation connects via a "tee" connection directly onto a MITS circuit, then with this option only the connection spur "leg" of the "tee" circuit would be charged as a local asset. Whilst it is apparent that the main MITS circuit would have been constructed regardless of the generation connection, it may be that this circuit and parallel circuits would have been reinforced to accommodate the output of the generation.

  This option means that for this example, either the entire MITS circuit is wholly treated as a generator only circuit or none of it is. Treating the entire circuit as a generator only circuit is unlikely to be acceptable because although it may ensure that the full cost savings associated with an SQSS design variation connection are passed to the generator, it is also likely to mean that costs that are caused by other users are also passed through to the generator.

National Grid believes that whilst this gives a simple methodology that is clear to users, it is unlikely to give a cost reflective result in all circumstances.

- **Marginal investment for generation**
  Where the connection of a generator has an impact on MITS circuits and circuits that are used by generation and demand, there is an option to include a marginal investment element to the local asset charge.

  This marginal investment could be calculated based on the impact of an additional MW of generation on MITS circuits or radial circuits that have a shared use (i.e. circuits used to serve demand and generation).

  When both generation and demand connects onto the MITS via a shared radial spur circuit, the local asset charge could be based upon the impact of an additional MW of generation along the circuit until the first MITS node. The first MITS node could be defined using a number of criteria although there are difficulties associated with producing a robust definition for all scenarios, for example, it could be defined as having four circuit connections, which may not accurately represent the spur length where the MITS consists of single circuits. An illustration of such an approach is shown in Appendix 1 (Example C).

  As discussed in GBECM 09[7], whilst it is difficult to quantify the marginal investment for generation that is teed into MITS circuits, the total length of the three “legs” of the tee circuit may provide a reasonable proxy. The actual marginal investment is influenced by a number of factors, including the location of other generation, the impedance and length of each of the tee circuit legs and the impedance of the parallel circuits. A standard estimation provides certainty and predictability to users but will not be cost reflective in all circumstances.

  National Grid believes that whilst using marginal investment for generation is more complex than identifying generation assets, it is likely to give a more cost reflective local charge for generation that connects with a tee into MITS circuits or with a radial circuit that has a shared (generation and demand) use.

4.1.2 Applicable voltages

Local asset charging allows a more specific expansion factor to be applied, which will improve cost reflectivity at voltages where there is a significant variance in £/MWkm costs. Expansion factors are calculated at the start of each Price Control period as future costs averaged by historic use for all types of circuit construction used at each voltage. The table below shows the cost variance[8] for specific circuit constructions against the GB expansion factors for each transmission voltage and for both overhead lines (OHL) and cables.

[7] Marginal investment for “tee” circuits are discussed in Section 6.2 (p.11) and Appendix Three (p.19).

[8] Derived from data submitted by all Transmission Owners for current Price Control period (Oct 2006) and in response to specific data requests as part of GBECM09 (August 2007)

	132kV		275kV		400kV	
	OHL	Cable	OHL	Cable	OHL	Cable
Variance compared to zonal expansion factor	295%	34%	22%	6%	13%	8%

It is apparent that the range of costs for 132kV circuits varies to a greater degree than those at 275kV and 400kV and therefore generation local asset charges could be applied at several connection voltages:

- 132kV connections only
- 132kV, 275kv and 400kV

National Grid believes implementing a local asset charge for 132kV assets only may be due discrimination as it would resolve the majority of instances where generation local asset charging currently lacks cost reflectivity, whilst minimising the impact on GB Users. That withstanding, the options being considered as part of the Transmission Access Review require a local asset charge to be determined for all generation connections to provide users with the option between long-term and short-term access and therefore local asset charging arrangements that are applicable across all voltages may be more appropriate.

4.1.3 Local Expansion Factors

Currently, expansion factors are calculated on a GB basis with only the Transmission Owner (TO) specific uprating factor[9] resulting in regional variance. In order to increase the cost reflectivity of a local asset charge, local expansion factors could be calculated from a weighted average of the circuits built in the respective generation zone or TO region.

More specific local expansion factors could be defined for other cost determining criteria, such as circuit tower type, route transmission capacity or single or double circuit configuration. For example cost variance is reduced if the 132kV OHL circuits are split into wooden pole or steel tower constructions. As shown above the variance for 132kV OHL as compared to the current zonal expansion factor is 295%. The table below shows the cost variance[10] if unique local expansion factors are calculated for both steel tower and wooden pole 132kV OHLs:

	132kV OHL	
	Steel tower	Wood pole
Variance compared to local expansion factor	35%	117%

The expansion factor cost variance has been reduced although it would be necessary to increase the specificity further if greater cost reflectivity was required. National Grid is seeking industry opinion on determining local expansion factors on a range of criteria:

- Geographic region
    - Generation zone
    - TO region
- Circuit criteria (examples include):
    - OHL tower type

[9] The uprating Factor takes into account the proportion of 132kV and 275kV circuits that are estimated to be rebuilt at 400kV in the near future.
[10] See note 6.

- Route transmission capacity
- Single/ double circuit

National Grid believes that local expansion factors derived from a smaller population may be more susceptible to cost volatility where a new connection could have an increased impact on the tariff of other local generators. A balance must therefore be achieved between cost reflectivity and predictability and stability for local expansion factors and therefore the local asset charge.

4.1.4 TEC or CEC

Under the specific treatment for generation connection assets approach, the local asset charge could be based upon:

- Transmission Entry Capacity (TEC) in MW;
- Connection Entry Capacity (CEC) in MW; or
- A new "Local Connection Capacity" limit in MW.

TEC represents the User's long term right to export onto the transmission system whereas CEC is the User's local connection design limit. Under some of the options being considered as part of the current Transmission Access Review, generators will use a combination of both long term access and short term access products. Under such conditions it may be more appropriate to reinforce the local transmission network to meet the full export capacity of the connection (i.e. CEC) or to a level (greater than TEC) specified by the User (i.e. a new definition 'Local Connection Capacity').

National Grid believes the local charge should be based upon the same criteria as the investment decisions, which may be CEC or Local Connection Capacity. Under a scenario where Users utilise a combination of short term and long term access products, a local charge based solely upon the long term component, TEC (reflecting the costs of the wider system), will lead to undercharging, thus a socialisation of local asset costs upon other Users.

Appendix 1 provides an illustrative example of an approach for applying a local asset charge based on the specific treatment of generation connections to several generator connection scenarios. Local asset charges are calculated for generation connected by a simple spur and an interconnected tee.

Overall, National Grid believes that the "specific treatment for assets local to generation connection" option maintains the advantages gained from the implementation of the connection "Plugs" methodology, particularly in shielding generators from the costs of assets installed as a result of TO decisions made for wider system reasons and decision made by other users. In addition, the transparent methodology is founded on simple concepts.

The precise definition of local assets is difficult to achieve without introducing significant complexity for such instances as "teed" spur connections or spurs that serve both demand and generation.

National Grid invites views on the principle of local charging based on the "specific treatment of assets local to generation connections". In addition, comment is requested upon the various sub options described.

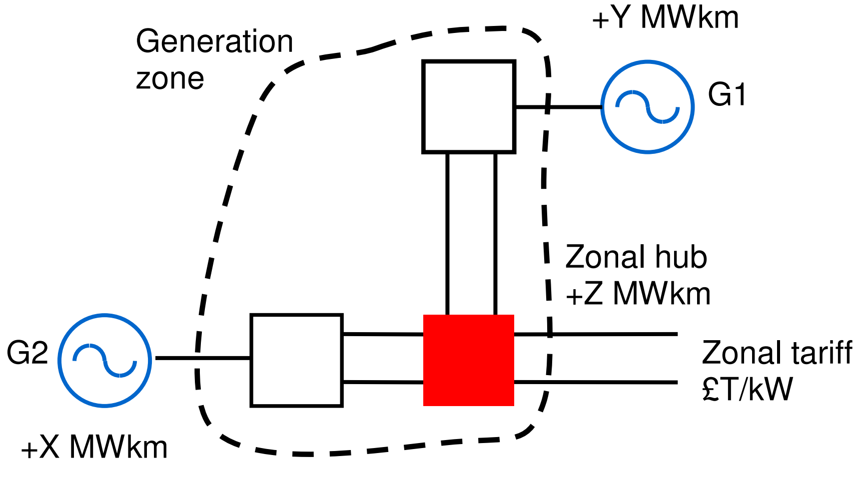
4.2 Specific treatment of distance to zonal hub

This option does not attempt to identify actual generation local assets but uses a numerical approach to represent their cost based upon the generator position in its TNUoS generation zone. It is recognised that transmission circuits local to generation can perform the dual role of bulk power transfer and local connection. The local asset charge represents the cost of transmission from the generator to the zonal hub, a specific point defined within each generation zone. The charge is a function of the marginal cost differential between the zonal hub and the generator and the construction type and security of the local generation connections.

The existing transport model charges generation based upon the cost of transmission from the cost weighted average of a zone of generation nodes with similar marginal costs. This approach then adds an additional step of calculating the cost of connecting into the zonal hub with local circuits.

The DCLF transport model would be run and generation zones determined, as now. The additional step introduced produces a nodal specific adjustment based upon the local specific circuit and levels of connection security within the generation zone. Whilst the existing zonal tariff represents the marginal cost of bulk transmission from the zone to the reference node, this local asset charge reflects the cost of transmitting the power from the generator to the zonal hub.

The diagram below illustrates a TNUoS generation zone which contains two units, G1 and G2. The total TNUoS tariff for each generator is determined from a local and a wider charge. The local charge is a function of the marginal cost differential between the node and a zonal hub, a local security factor and expansion factor differential. The wider charge is a zonal tariff:



G1 TNUoS tariff (£/kW) = [(Y-Z) x (EF_{LOCAL}-EF_{WIDER}) x Local Security Factor] + Zonal tariff (£T/kW)

G2 TNUoS tariff (£/kW) = [(X-Z) x (EF_{LOCAL}-EF_{WIDER}) x Local Security Factor] + Zonal tariff (£T/kW)

For each generation node, the marginal investment differential is converted to a local asset charge with a specific security factor and specific expansion factor. A number of different approaches can be taken in determining these factors and National Grid invites the industry's view on each of the sub-options below:

4.2.1 Local Expansion Factors

The type and therefore cost of circuits used for bulk transmission differs from those used for generation connections especially those at 132kV. Within the existing methodology, a generator's tariff is based upon a weighted average expansion factor which is therefore dominated by the longer circuits used for bulk transfer.

The expansion factor used to calculate the local asset charge should be the differential between the local expansion factor and the "wider" expansion factor already used in the transport model as the basis of the zonal tariff. This should avoid double counting of circuit costs.

For any approach that defines the zonal hub through a weighted average calculation, the differential in MWkm between the generation node and zonal hub represents a difference in marginal investment rather than a physical connection between two nodes i.e. the zonal hub is not a physical point. For this reason, it is not possible to identify actual circuits and therefore circuit voltages or conductor/tower types. Consequently assumptions are required to determine the local expansion factor between local and MITS circuits. Possible approaches include:

- Calculation of volume weighted zonal averages for generation zone or TO region;
- A simplified model approach, for example the circuit type and voltage of the circuits that connect a generation node would determine the local expansion factor;
- An average of those circuits that connect directly to generation nodes in a zone, TO region or on a GB basis

If the node with the lowest secured, or unsecured, marginal cost is used as the zonal hub, it would be possible to identify the physical circuits between generation node and zonal hub. Consequently, in additional to the averaging approaches given above, this would also allow the calculation of a local expansion factor which was a weighted average of the various parallel paths between the nodes. Power flow analysis would be required to determine relative circuit flows which would increase complexity.

National Grid believes a balance must be attained between stability (achieved with averaging) and cost reflectivity (achieved by basing costs on specific local circuits). If a straight volume weighted approach is taken, the expansion factor calculation may be dominated by long bulk transmission circuits running through the zone rather than the actual local connection circuits. Conversely, if a simple model is assumed such estimation will reduce cost reflectivity in some instances.

4.2.2 Local Security Factor

The Charging Methodology calculates charges under the assumption that all generation nodes are connected with the GB average level of connection security, currently 1.8. In order to improve cost reflectivity, the distance to zonal hub local charge could be derived from the actual local connection security. This would allow the full cost implications of different investment decisions associated with connection security to be reflected onto the User.

As previously discussed, for zonal hubs that are based upon weighted averages it is not possible to identify actual physical circuits that connect the generation node to the zonal hub, and so two possible approaches have been identified:

- **Security factor simplified assumptions**
  The local asset charge would be based on the level of security of the circuits directly connecting the generation node.

- **Seculf**
  Alternatively the output of the secured load flow model (Seculf) could be used. By using the secured marginal costs for each node to calculate the zonal hubs and nodal differentials, the local security is inherently incorporated.

National Grid believes an approach based on assumptions is simple and predictable although it would affect cost reflectivity in some instances. The use of the secured marginal kilometres means that the full impact of complex connection decisions is reflected into the local asset charge although predictability and transparency may be reduced. In addition, there may be a need for National Grid to explore how the Seculf model could be made more transparent to users.

4.2.3 Selection of zonal hub

The zonal hub could be determined from a range of criteria:

- Generation marginal cost weighted average. This represents the average generation investment for all generators in a zone.
- Generation node with lowest marginal cost. This ensures that all differentials will always be positive.
- Demand cost weighted average for all nodes with demand within the generation zone. This effectively represents the “centre” of local demand.

The zonal hub criteria above are derived using nodal marginal costs, from the DC Load Flow model that assumes an intact system. As previously discussed, the output of the Seculf model could be used to calculate marginal cost differential, thereby inherently incorporating local security factors. All three zonal hub criteria could be applied to secured marginal costs.

If the generation marginal cost weighted average is chosen around half of the nodes would have a negative local differential. National Grid is concerned that this may create an issue with the treatment with negative differentials in that they may incentivise behaviour that leads to inefficient asset investment.

National Grid believes that the use of the generation node with the lowest marginal cost eliminates this issue, although this would lead to a zero local asset charge for generation at this node in each zone. If the node with the lowest secured marginal cost is used, then although the local asset charge will be zero, the cost implications of decisions on connection security will still be reflected but through the wider zonal charge. This is also more consistent with a local charge for short term access, i.e. it avoids a charge that is with reference to an arbitrary hub that joins TNUoS wider zonal and local charging, but for parties who do not pay the zonal TNUoS tariff.

Based on initial analysis National Grid understands that the zonal hub based upon demand reduces the likelihood of negative differential and ensures that a positive local asset charge is produced for all generation nodes.

The zonal tariff, for the use of "wider" infrastructure assets, must be derived from the marginal cost of the same zonal hub as used to calculate the local asset charge, to avoid double counting. The current basis for generation zonal TNUoS tariffs is the unsecured marginal cost weighted average and therefore if another zonal hub is used there will be an impact on zonal tariffs.

In order to fully assess the choices for zonal hubs, the options should be considered against a regime with short term access. The charge for short term access would be a function of the cost of constraining off other generation. This may infer that a local asset charge based upon a zonal hub determined by the generation marginal cost may be appropriate, as this best represents the generators most likely to be constrained off. That withstanding, it could be argued that if short term access is achieved by the supply of local demand then the demand cost weighted average nodal hub should be used.

Appendix 2 illustrates two approaches for calculating the generation local asset charge based upon the specific treatment of distance to a zonal hub. A fictitious generation TNUoS zone has been created for this example. The first example assumes a zonal hub based upon the generation node with the lowest marginal cost and a security factor derived from the seculf model. The second uses the demand marginal cost weighted average as the zonal hub and makes simplified assumption for both security and expansion factors.

In general, National Grid believes that the "specific treatment of distance to zonal hub" high level option retains the advantages gained from the implementation of the "Plugs" methodology namely in protecting Users from TO wider infrastructure investments decisions. Calculation is likely to be straightforward and derived within the transport model, although the principles are more complicated and transparency may be reduced. National Grid invites views on this approach and the sub-options for implementation.

4.3 Substation Assets

As was discussed during the development of the recent consultation Charging Arrangements for Design Variation Connections, GBECM-09, in order to ensure the full cost signals associated with a connection investment decision, both the circuit and substation differential costs should be reflected upon the User. For the MITS the cost of substation infrastructure assets are covered on a flat £/kW basis via the TNUoS residual charge. Both the approaches discussed above, could include a charging element for local generation substation assets.

A possible approach would be to perform cost analysis for a number of generic substation configurations:

- **Connection designs – Single/ double circuit**
  This ensures the capital savings associated with design variation connections are reflected in a user's charge.
- **Substation voltage**
  This mitigates the £/kW cost variance that exists between connection voltages.

This would allow a £/kW cost to be calculated for the substation, into which the generator connects. Such a cost could be calculated on a number of levels:

- **Zonal**

This ensures the substation charge is a cost reflective average of typical local configurations. The small sample size increases the likelihood of higher volatility.

- **TO region**
  The substation costs take into account specific connection cost variances between each Transmission Owner.
- **Great Britain**
  The average substation costs could be determined on a GB basis. This would ensure that the largest population of historically used assets is used which increases the resultant stability of the substation charge.

In a number of cases, a significant majority of the local asset cost associated with small generators "teed" directly onto MITS circuits are infrastructure substation assets. Substation costs determined for single and double circuit connections for each transmission voltage calculated on either a TO or Great Britain basis would seem to provide the correct balance between stability and cost reflectivity.

An illustration of the substation component for generation local asset charges are shown in Appendix 3, where a GB average £/kW charge is calculated for each voltage for both single and double circuit connection designs. Such charges would be applied to all generation as a component of their local asset charge. The revenue collected would reduce the size of the residual component of TNUoS.

National Grid invites views on the appropriateness of a substation element in a local connection charge and specifically on the various options discussed above.

4.4 Deepening of the infrastructure/ connection asset charging boundary

This option involves a return to a deeper connection/use of system charging boundary for generation connections. This could apply to all generators or just those connected at 132kV. The generator connection substation and spur circuits would be charged as connection assets and therefore, the full costs associated with each specific connection would be reflected upon the customer. This requires the full cost of both circuits to be charged as connection assets to reproduce the full asset cost.

It is worth noting that this is different from the previous 'generator only spurs' arrangements where half the value of the second spur circuit was classed as infrastructure to reflect the general benefit of this additional security.

The savings associated with any design variation would be passed through to the customer, allowing the customer to compare these savings with the loss of revenue associated with the uncompensated access restrictions. This should lead to efficient transmission investment.

The definition of a consistent boundary between connection and infrastructure assets is problematic given the variety of existing and proposed connection designs. This is likely to lead to complex arrangements that lack transparency. For example, if the boundary was to be deepened for spurs that only served generation, the connection of a small quantity of demand at the end of a long spur would prohibit this being shared as connection assets.

4.4.1 Connection Asset Sharing Methodology

Generation spurs often connect multiple parties and with a deep connection boundary will require a sharing methodology for the apportionment of the connection charges. Options include pro-rating by:

- **Transmission Entry Capacity (TEC)**
- **Connection Entry Capacity (CEC)**
- **Fault level contribution**

All such approaches produce estimates that will not be cost reflective in some instances, for example, a small renewable unit may connect at a substation with a large thermal plant. In this example, the ratio of the generator's TECs, CECs or fault level contributions will be much higher than the ratio of the investment costs resulting from the connection.

National Grid believes deepening the connection boundary directly exposes the customer to TO decisions made for wider system reasons. For example, if the TO believes that more generation will connect at a site in the future, a substation with additional capacity would be constructed, but until the additional generation connects the original User will have to pick up the cost for these additional assets. In addition, a generator connecting to an existing spur, further utilising existing assets, will experience a step increase in charges when it is deemed that the end of the asset life has been reached and the assets need to be replaced.

It should also be noted that a generator choosing a single circuit connection would be exposed to an unpredictable step change in charges if future customer connections necessitated the second circuit.

National Grid believes that although a 'deeper' connection/use of system charging boundary may increase the accuracy of local asset charging in certain scenarios, but there are significant risks introduced for generation. The generator is vulnerable to wider TO decisions taken for strategic system regions. In addition, there are significant practical difficulties associated with the definition of a consistent connection boundary.

5. Responses to this pre-consultation

Comments and views are invited on all of the issues and sub-options raised in this pre-consultation document. To ensure that your comments and views are considered as part of National Grid's forthcoming consultation document, responses must be received by close of business on Thursday 27 March 2008.

If you wish to provide comments on this pre-consultation document, responses are welcome via email to: thomas.ireland@uk.ngrid.com

Alternatively, Users can send their comments in writing, addressed to:

Tom Ireland
Electricity Charging & Access Development
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

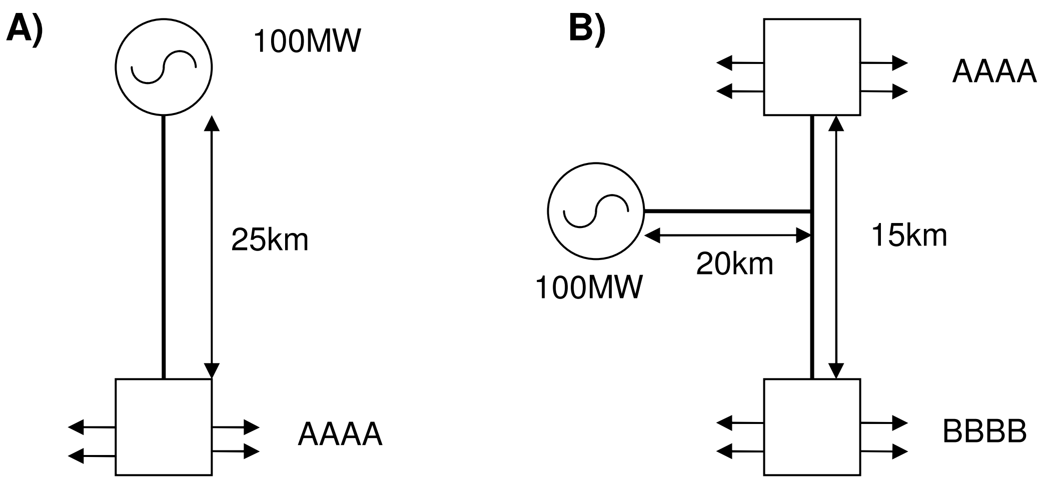
If you have any further queries, please do not hesitate to contact Tom on 01926 656152.

Appendix 1 – Illustration of specific treatment of generation connections

In order to illustrate the specific treatment of generation connections let us assume the example of a 100MW TEC generator connecting. The following assumptions are made:

- Only the circuit element of the charge has been considered;
- In order to estimate actual site specific costs, overhead line and tower capital costs have been taken from a paper by KEMA[11] consulting;
- The local expansion factor for 132kV overhead line is 6.0 and was calculated on a TO average basis;
- L4 steel towers are used for both single (162MW) and double (324MW) circuit connections;
- The 2008/9 transport and tariff model has been used;
- The circuit "tee" point is halfway between AAAA and BBBB in Example B.

The two possible connection configurations considered, A and B, are shown below:



Example A – Generator spur

Generator local charge (£/kW) $= \frac{L_{SP} \times EC \times LEF \times SSF}{1000}$

Where
L_{SP} = Spur Length (km)
EC = Expansion Constant (£/MWkm)
LEF = Local Expansion Factor
SSF = Specific Security Factor

$$= \frac{25 \times 10.29 \times 6.0 \times 1}{1000}$$

= £1.54/kW

For the avoidance of doubt a single circuit spur would have a specific security factor of 1 whereas a double circuit would have a specific security factor of 2, in this example.

[11] Review of the Electricity Transmission Asset Management Policies and Processes of Scottish Power Ltd – Draft Final Report – 6 July 2006 KEMA Limited

After the removal of generation local assets from the DCLF transport model, the base zonal tariff for the generation zone is £16.20/kW. The final TNUoS tariff would be:

= "Wider" charge + "Local" charge

= 16.20 + 1.54

Total TNUoS tariff (£/kW) = £17.74/kW

To enable comparison, if the existing transport and tariff model was run for this additional 100MW generator to connect into AAAA, the TNUoS tariff for its respective generation zone would be **£17.23/kW**.

Example B – Interconnected tee connection

$$\text{Generator local charge (£/kW)} = \frac{L_{SP} \times EC \times LEF \times SSF}{1000}$$

$$= \frac{20 \times 10.29 \times 6.0 \times 1}{1000}$$

Local asset charge (£/kW) = £1.23/kW

After the removal of generation local assets from the DCLF transport model, the base zonal tariff for the TNUoS zone would be £16.22/kW therefore the total tariff would be:

= "Wider" charge + "Local" charge

= 16.22 + 1.23

Total TNUoS tariff (£/kW) = £17.45/kW

For comparison, after the addition of a 100MW generator teed onto the AAAA – BBBB circuit the existing transport and tariff model would produce a TNUoS zonal tariff of **£17.32/kW**

SQSS Design Variation Investment Signals for Example A and B

Using generic costing data, the actual cost saving between a single circuit and double circuit connection, for Examples A and B, is £2.94/kW and £4.12/kW respectively. Substation asset costs have not been considered. For example B, it has been assumed that double circuit security would be provided by a second tee connection.

The table below compares the signal produced by the specific treatment of generation connections methodology to the estimated actual investment cost savings.

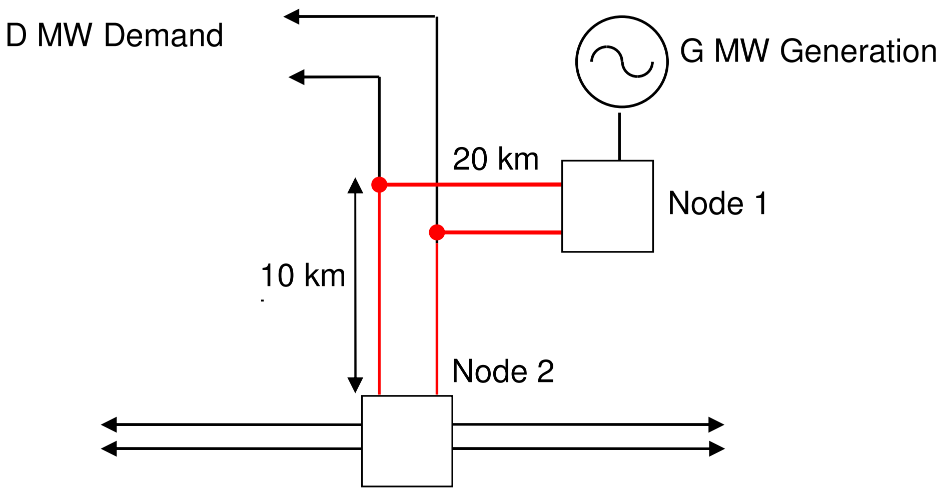
	Example A	**Example B**
Single circuit tariff (£/kW)	17.74	17.45
Double circuit tariff (£/kW)	19.28	18.69
Differential (£/kW)	1.54	1.24
Site specific estimated cost saving (£/kW)	2.94	4.12

For Example A, the simple spur, the difference between the site specific cost savings and that produced by the local asset charges results from two factors. Firstly, the local expansion factor is based an average, which is not equal to the actual cost of the circuit. Secondly, the local asset charges have been derived using TEC. In this example, the generator has a TEC of 100MW (although CEC is 162MW) as compared to the OHL capacity of 162MW. If it is assumed that the OHL was constructed to match generator CEC and the local asset charged was calculated on a CEC rather than a TEC basis then the single circuit/ double circuit differential would increase to £2.49/kW.

The difference between the site specific cost savings and that produced by the local asset charges in Example B, the interconnected tee connection, can partly be explained by the same two factors described above. In addition the local charge only covers the spur component of the tee circuits. This is incorrect, in several scenarios, for example if double circuit security was provided by a second tee circuit or by ‘turning in’ the MITS circuit.

Example C: Marginal investment for generation

The illustration below shows a demand spur with a “teed” generation connection. The generation marginal investment approach estimates the cost of the generation spur and the cost of reinforcement of the shared circuit as a result of the generation connection:



In this example, generation is connected at node 1, and node 2 is defined as the first MITS node for the generator. If G>D, an additional MW of generation at node 1 would flow in the two circuits from node 1 to the “tee” point and in the two circuits from the “tee” point to node 2. This would give a local marginal investment cost of:

L_{Local} = (0.5MW×20km)+(0.5MW×20km)+ (0.5MW×10km)+(0.5MW×10km) = 30MWkm

The local asset charge using a marginal investment approach would then be calculated as follows:

$$\text{Generator local charge (£/kW)} = \frac{L_{Local} \times EC \times LEF \times SSF}{1000}$$

Where
L_{Local} = Local marginal investment cost (MWkm)

EC = Expansion Constant (£/MWkm)
LEF = Local Expansion Factor
SSF = Specific Security Factor

$$= \frac{30 \times 10.29 \times 6.0 \times 2}{1000}$$

= £3.70/kW

If G<D, the local marginal investment cost would be:

$L_{Local} = (0.5MW \times 20km)+(0.5MW \times 20km)+(-0.5MW \times 10km)+(-0.5MW \times 10km) = 10MWkm$

$$\text{Generator local charge (£/kW)} = \frac{L_{Local} \times EC \times LEF \times SSF}{1000}$$

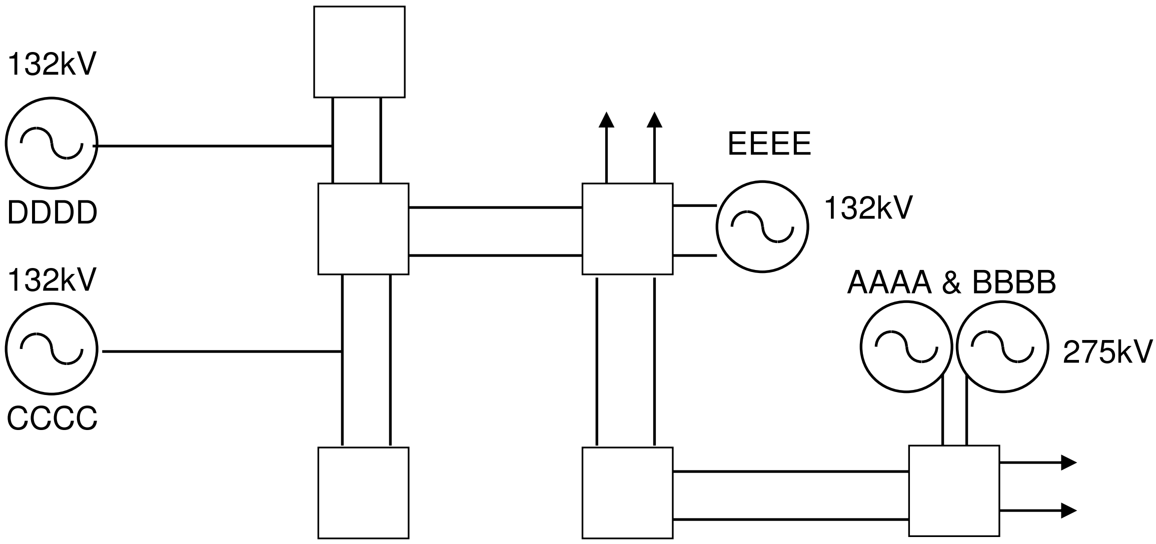
Where
L_{Local} = Local marginal investment cost (MWkm)
EC = Expansion Constant (£/MWkm)
LEF = Local Expansion Factor
SSF = Specific Security Factor

$$= \frac{10 \times 10.29 \times 6.0 \times 2}{1000}$$

= £1.23/kW

Appendix 2 – Illustration of Distance to Zonal Hub Charges

An illustration of two possible methodologies for applying a specific approach to distance to zonal hub charging is shown below for the generation connected in a single TNUoS generation zone. A simplified schematic has been provided:



A number of assumptions have been made:

- Zonal specific overhead line local expansion factors are 5.0 for 132kV and 2.28 for 275kV;
- The 2008/9 transport and tariff model has been used;
- Only the circuit asset costs have been considered;
- The 2008/9 expansion constant of £10.29/MWkm has been used.

The illustrations assume the following local and wider expansion factors:

	EF Local	EF Wider	EF Differential
132kV	5.00	2.24	2.76
275kV	2.28	1.14	1.14

The table below summarises some of the relevant nodal data from the transport and the Seculf model:

Node	Voltage	MW	Unsecured nodal cost (km)	Secured nodal cost (km)
AAAA	275	252	545.6	1001.1
BBBB	275	252	545.6	1001.1
CCCC	132	45	575.2	933.7
DDDD	132	20	593.6	952.1
EEEE	132	120	513.3	879.2

The potential zonal hubs discussed in section 4.2 are shown below:

Zonal hubs	Marginal cost (km)
Generation cost weighted average	543.9
Lowest generation node	513.3
Demand cost weighted average	509.0

Example 1
Zonal hub: Lowest secured marginal cost generation node
Local security factor: Nodal secured costs taken from Seculf model
Local expansion factor: Simplified assumptions – zonal average

This approach uses the output from the secured load flow, or Seculf, model and the chosen zonal hub is the generation node with the lowest secured (or post fault) marginal cost. Differentials are relative to the secured cost for each generation node. Consequently the local security factor is inherently considered.

The lowest secured marginal cost generation node is EEEE at 879.2km.

Local asset charge (£/kW) =

$$\frac{\text{Secured marginal cost differential x expansion factor differential x expansion constant}}{1000}$$

Node	Secured nodal cost differential (km)	Secured marginal differential (km)	EF Differential
AAAA	1001.1	121.9	1.14
BBBB	1001.1	121.9	1.14
CCCC	933.7	54.5	2.76
DDDD	952.1	72.9	2.76
EEEE	879.2	0.0	2.76

e.g. For DDDD = $\frac{(952.1 – 879.2) \times 2.76 \times 10.29}{1000}$

= £2.07/kW

The existing methodology bases the generation zonal tariff on the generation cost weighted average for a zone whereas if this approach was implemented the zonal tariff would be based upon the zonal hub which is the lowest secured marginal cost generation node. To prevent double counting the existing output from the transport and tariff model must be adjusted by the differential between the two:

Adjustment = expansion constant x differential between hubs x 0.001

= 10.29 x [(543.9*1.8) – 879.2] x 0.001

= £1.03/kW

Node	Local Asset Charge (£/kW)	Zonal Hub Adjustment (£/kW)	TNUoS net change (£/kW)
AAAA	1.43	-1.03	0.40
BBBB	1.43	-1.03	0.40
CCCC	1.55	-1.03	0.52
DDDD	2.07	-1.03	1.04
EEEE	0.00	-1.03	-1.03

If DDDD was connected by a double circuit the secured marginal cost at the node would increase to 972.1MWkm. This would result in a local asset charge of £2.64/kW or an increase of £0.57/kW compared to that of the single circuit connection. The 132kV spur circuit at DDDD is 4km long.

In this illustration the zonal hub has been defined as the generation node with the lowest secured marginal cost, namely EEEE. As a consequence, the local asset charge will inherently be zero at this node. Under this approach, the zonal tariff is determined by the secured marginal cost at this node and therefore the impact of connection security design decisions will be reflected in the "wider" zonal charge rather than the "local" charge for connections at this node.

Example 2
Zonal hub: Demand marginal cost weighted average
Local security factor: Simplified assumptions for security
Local expansion factor: Simplified assumptions – zonal average

The zonal hub used is the demand marginal cost weighted average for the generation zone and is equal to 509.0kms. The nodal security factors are based upon the circuits that actually connect directly to the generation node.

$$\text{Zonal hub charge (£/kW)} = \frac{\text{Marginal cost differential x EF differential x Nodal SF x EC}}{1000}$$

Node	Nodal cost (km)	Marginal Cost Differential	Expansion Factor Differential	Nodal Security Factor
AAAA	545.6	36.6	1.14	2
BBBB	545.6	36.6	1.14	2
CCCC	575.2	66.2	2.76	1
DDDD	593.6	84.6	2.76	1
EEEE	513.3	4.3	2.76	2

E.g. For BBBB:

$$\text{Local asset charge (£/kW)} = \frac{36.6 \times 1.14 \times 2 \times 10.29}{1000}$$

$$= £0.86/kW$$

The existing methodology bases the generation zonal tariff on the generation cost weighted average for a zone whereas if this approach was implemented the zonal tariff would be based upon the zonal hub which is the demand marginal cost weighted average. To prevent double counting the existing output from the transport and tariff model must be adjusted by the differential between the two:

Adjustment = EC x Differential between hubs x LSF x 0.001

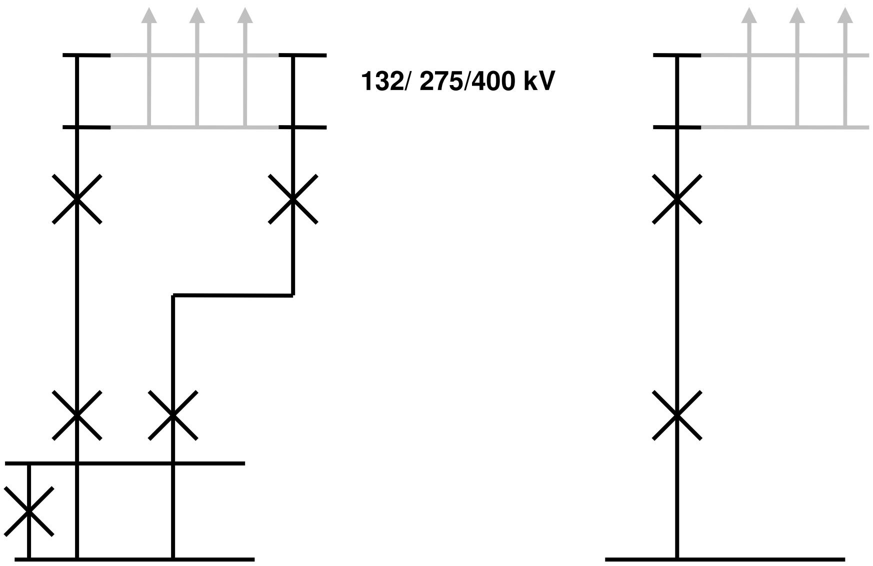
= 10.29 x (509.0 – 543.9) x 1.8 x 0.001

= - £0.65/kW

Node	Local Asset Charge (£/kW)	Zonal Hub Adjustment (£/kW)	TNUoS net change (£/kW)
AAAA	0.86	-0.65	0.21
BBBB	0.86	-0.65	0.21
CCCC	1.88	-0.65	1.23
DDDD	2.40	-0.65	1.75
EEEE	0.24	-0.65	-0.41

Appendix 3 – Illustrative local asset charges for remote end substation assets

As part of the previous work on the charging arrangements for design variation connections, generic costing data was submitted by all the GB TOs. Capital costs were provided for the following double and single circuit generic generation connection designs at 132kV, 275kV and 400kV connections:



Previously, the generic capital cost data was used to determine cost differentials between single and double circuit connections. In this instance it has been used to calculate a substation local asset charge based upon average capital costs for various voltages and levels of connection security.

An annuitised, GB average was calculated for non locational assets. This annual capital cost was converted into a £/kW value by assuming the following average generator sizes derived from the TNUoS model:

	400kV	275kV	132kV
Typical generator size (MW)	1365	645	55

It was assumed that the substation costs could be equally apportioned to the MITS substation and the substation to which the generator is connected. The table below shows the resulting substation local asset charges:

	400kV	275kV	132kV
Double circuit (£/kW)	0.43	0.60	4.21
Single circuit (£/kW)	0.21	0.38	2.32