FURTHER CONSULTATION DOCUMENT

GB ECM-08

Modification proposal to the Transmission Network Use of System Charging Methodology to introduce charging arrangements associated with Offshore Transmission Networks

October 2008

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1. Executive Summary

This consultation document sets out National Grid's proposals for the charging arrangements for offshore transmission networks, which will apply following the commencement of the forthcoming regulatory regime for offshore transmission.

National Grid has previously published a pre-consultation document (in July 2007) and an earlier consultation document (in December 2007) on this issue. Ofgem wrote to National Grid on 30 May 2008 requesting that National Grid undertake a supplementary consultative process, and this document forms that further consultation.

National Grid welcomes all industry views on these proposals, and on options discussed in this document, as well as any alternatives.

This 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 across 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 consultation National Grid's proposals for the charging arrangements for offshore transmission networks, which will apply following the commencement of the forthcoming regulatory regime for offshore transmission.

3. Background

In March 2006, the government concluded[1] that offshore electricity transmission should be regulated under a licensed price control approach.

In May 2006, the government informed interested parties that the Secretary of State was minded to extend the role of the current onshore GB System Operator (GBSO) – occupied by National Grid – offshore. On 2 August 2006 the Secretary of State issued a statement confirming National Grid as offshore GBSO designate.

In March 2007, the government decided that the offshore electricity transmission regime should be a competitive, or non-exclusive, rather than an exclusive monopoly activity. Following this decision, Ofgem published a second scoping document[2] setting out some initial views as to how a competitive transmission regime, under the auspices of a licensed price control, might work. The second scoping document set out Ofgem's "initial thoughts" in each of the work streams established to deliver the offshore transmission project.

In terms of charging, Ofgem proposed that the current licence driven approach applied onshore would be an appropriate basis for developing offshore charging arrangements and expected that the current GB charging methodology will be used as the basis for the development of offshore arrangements. Ofgem stated that National Grid, as onshore GBSO and offshore GBSO designate, should consider the detailed changes required to apply the charging methodologies offshore, the

[1] http://www.dti.gov.uk/energy/sources/renewables/policy/offshore-transmission/offshore-tranmission-consultation-decision/page28690.html
[2] http://www.ofgem.gov.uk/Networks/Trans/Offshore/ConsultationDecisionsResponses/Documents1/070330_2ndOffshoreScopingDoc_final_am.pdf

timescales for implementing these, and the consequential changes to the onshore arrangements.

Ofgem have since confirmed that they believe that the onshore licence based approach will best deliver the appropriate charging arrangements for offshore transmission within the available timescales. Ofgem have also agreed that National Grid, as onshore GBSO and offshore GBSO designate, will be responsible for developing open, non-discriminatory charging methodologies that apply to those wishing to connect to and use the offshore transmission systems.

Ofgem and National Grid have agreed that, in progressing the development of an offshore charging regime, National Grid will apply the same primary objectives as for onshore (described in Introduction above).

In considering the application of the onshore charging regime offshore, National Grid has identified a number of issues that require further attention, and issued a pre-consultation document[3] in July 2007 to discuss these. Following consideration of the resulting responses, National Grid issued a consultation document[4] in December 2007 setting out National Grid's proposals to modify the Use of System Charging Methodology to implement a charging regime offshore.

On 30 May 2008 Ofgem wrote to National Grid to highlight certain concerns with National Grid's proposals. They requested that a supplementary consultative process be undertaken, and this document forms that further consultation, in that it discusses Ofgem's concerns, and sets out for consultation National Grid's revised proposals.

In addition to the issues which have previously been consulted on, charging arrangements will need to be developed to address situations where offshore transmission networks at 132kV connect to onshore distribution networks ("Embedded Transmission"). This was not included in the December 2007 consultation, due the formation of the Offshore Transmission Embedded Transmission Working Group ("OTETWG") in January 2008. Following the conclusion of this group, this document sets out National Grid's proposals in this area.

4. The Pre-consultation and first Consultation

National Grid has previously issued a pre-consultation and a consultation document which discuss the main issues that would need to be addressed in order to extend the application of the onshore charging regime offshore. These have also been debated at various Industry meetings, such as the TCMF and CISG.

The three main issues highlighted in the pre-consultation and consultation were:

1. Offshore connection / use of system boundary;
2. Offshore Expansion Factors; and
3. High Voltage Direct Current.

[3] http://www.nationalgrid.com/NR/rdonlyres/0DF19996-2131-406A-B6C2-28C31C5ABBE4/18307/OffshoreChargingPreconsultationGBECM08.pdf
[4] http://www.nationalgrid.com/NR/rdonlyres/5A5364ED-5EF5-4D37-9FA6-DEB41C16F717/22313/GBECM08OffshoreChargingConsultation.pdf

Nine written responses to the pre-consultation were received. These can be viewed on the National Grid charging website, and are summarised in the December 2007 consultation document.

Ten written responses to the consultation were received, and these can also be viewed on the National Grid charging website.[5] The issues raised in the pre-consultation and consultation documents, and the views expressed by respondents to the consultation, are set out in more detail below.

4.1 Offshore Connection / Use of System Boundary

The boundary between connection assets and transmission system infrastructure assets is defined in the Connection Charging Methodology. In general, connection assets are defined as those assets solely required to connect an individual User to the GB transmission system, which are not and would not normally be used by any other connected party (i.e. "single user assets"). Connection charges are levied directly on the relevant party, and enable National Grid to recover, with a reasonable rate of return, the costs involved in providing connection assets.

The costs of transmission system infrastructure assets are recovered through Transmission Network Use of System (TNUoS) charges, levied on all Users of the transmission system. The underlying rationale behind TNUoS charges is that efficient, economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, relative tariffs should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems.

The TNUoS charge is itself made up from two elements:

- A locationally varying element determined within the Investment Cost Related Pricing (ICRP) DC Load Flow (DCLF) transport model to reflect the different costs of capital investment in and maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations; and
- A flat residual element to ensure correct overall cost recovery.

The first step in setting charges is therefore to define the boundary between connection assets and transmission system infrastructure assets. However, before this can be considered, it is necessary to consider the default ownership boundary offshore.

The GB Security and Quality of Supply (GBSQSS) subgroup initially concluded that the Offshore Grid Entry Point (i.e. the ownership boundary between the User and the transmission system) would be at the disconnector on the busbar side of the circuit breaker on the Low Voltage (LV) busbar on the outgoing windfarm circuits on the offshore platform. However, following discussion within the Offshore Grid Code group, it was agreed that offshore generators should have the option to connect to an Offshore Transmission Owner (OFTO) at a voltage level of their choosing (e.g. 33kV, 132kV, 220kV). It is therefore assumed that the offshore substation LV busbar represents the default ownership boundary offshore.

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

Since the offshore cables, switchgear, transformers and platform are all sharable or potentially sharable with the standard design considered by the GBSQSS Subgroup, the application of the existing onshore connection / use of system boundary would result in almost all assets being treated as transmission system infrastructure assets. The cost of these assets would be recovered through TNUoS charges.

Given the high capital cost of offshore transmission assets, the pre-consultation document then highlighted the effect this would have on TNUoS charges in further detail. Essentially, due to the high costs of offshore generation connections, and the 73%/27% split in revenue recovery from demand and generation, as more offshore generation connects, an increasing proportion of the overall 27% of revenue to be recovered is attributable to the locational element incurred by offshore generators. This will have the effect of decreasing the revenue to be recovered from onshore generators, and increasing the amount of revenue to be recovered from demand customers (as the overall amount of revenue to be recovered, and therefore the 73% share attributable to demand, will have increased).

Given the differences between onshore and offshore networks, National Grid therefore identified three options for consideration in the pre-consultation document:

1. **As onshore – Offshore substation LV Busbar**
   (Disconnector on busbar side of circuit breaker on outgoing windfarm circuit)
   This would be consistent with the onshore regime. At time, it was envisaged that the costs of offshore cables would be recovered through the locational element of TNUoS faced by the offshore generator, and the offshore substation assets would be funded through the residual element of TNUoS.

2. **Offshore substation High Voltage (HV) Busbar**
   (Disconnector on busbar side of circuit breaker on transformer circuit)
   The offshore platform, switchgear and transformers would be treated as connection assets, whereas the cable would remain as infrastructure.

3. **Onshore connection point**
   All offshore assets would be treated as connection assets with the Connection/Use of System boundary being at the onshore connection point.

In the December 2007 consultation, National Grid proposed that the offshore connection / use of system boundary would be at the offshore substation LV busbar (the disconnector on the busbar side of the circuit breaker on the outgoing windfarm circuit - option 1 in the pre-consultation). As this is consistent with the current onshore arrangements, no changes to the Statement of the Connection Charging Methodology would be required.

Offshore substations and cables could potentially be shared, with a number of different users connecting to an offshore substation. Although this has not been observed in the projects connected to date under the interim merchant regime, proponents of the enduring offshore transmission regime point to the increased co-ordination that would result from the new arrangements as better facilitating sharing.

Adoption of either of the other options highlighted in the pre-consultation would therefore represent a departure from the existing "plugs" shallow connection charging regime onshore, in that the costs of potentially shareable assets would be recovered through connection charges. Option 3, where the connection charging boundary would be at the onshore connection point, would further contravene the existing principle that circuits greater than 2km in length are treated as infrastructure, even if they are not potentially shareable.

It was noted in the pre-consultation that offshore transmission substations differ from those onshore in that they are housed on expensive platforms. The costs of offshore cables may also be (but need not be) more expensive than those onshore. Consequently, it was therefore questioned as to whether a similar treatment as for onshore was appropriate.

As previously noted, due to offshore generators paying for relatively expensive offshore connections and the requirement to maintain an overall split in revenue recovery of 73%/27% between demand and generation, tariffs faced by onshore generation and demand customers could be significantly affected. Treating all offshore networks as connection assets would leave onshore tariffs unaffected.

However, in order to implement such a change, a charging methodology for shared connection assets between multiple users would be required. This would expose users to the actions of other generators, a key reason for the move to the “plugs” shallow regime onshore. Offshore generators would also be fully exposed to costs resulting from wider OFTO decisions to provide additional assets for future connectees, as the costs of these additional assets, including substation assets, would be included in the connection charge.

National Grid noted that there will be different cost levels onshore for both circuits and substations. The differing costs of circuits are reflected through expansion factors, whereas the costs of substations are socialised through the residual charge. Given that the existing methodology covers different cost levels onshore, we questioned whether a different treatment is required offshore and whether there was a compelling argument for an alternative approach of recovering the costs of either offshore substation assets, or offshore substation and cable assets, through connection charges.

It is for these reasons that we proposed that the offshore connection / use of system boundary would be at the offshore substation LV busbar. As this is consistent with the current onshore arrangements, no changes to the Statement of the Connection Charging Methodology would be required. The exact methodology by which the costs of offshore substation and cable assets would be recovered through TNUoS charges is described in the next sub-section.

Respondents’ Views

Seven respondents to the consultation believed that the offshore connection / use of system boundary should be at the offshore substation LV busbar (option 1). These respondents believed that this would be consistent with the onshore arrangements, and with the principle that circuits greater than 2km in length are treated as infrastructure, even if they are not potentially shareable. One respondent further noted that treatment of offshore substation assets as infrastructure would also protect the generator from the potential cost of overprovision of connection assets by the OFTO in anticipation of future connections.

However, other respondents noted a number of perceived disadvantages with the proposal. One pointed to the additional complexities and costs offshore, and considered that, as it would be the choice of the user to locate offshore, it would not be reasonable to expect onshore users to incur additional charges as a result. Other respondents also suggested that the nature, and costs, of offshore assets is very different to onshore, and that socialising such costs would result in an inappropriate subsidy for offshore generators. These respondents believed that offshore transmission assets, although potentially shareable, are in practice unlikely to be shared with other users. Two of the three respondents not to support the proposal suggested that National Grid revisit option 3 from the pre-consultation, the connection boundary at the onshore connection point.

4.2 Offshore Circuit Expansion Factors

We noted that, if a proposal to treat offshore cables as infrastructure assets is adopted, such cables will need to be added to the ICRP DCLF transport model. The model calculates the effect of an incremental increase in generation (and demand) at each node on the transmission system. This effect is expressed as a change in the size of the transmission system in megawatt kilometres i.e. the net change in total system kilometres for a 1MW injection at a node.

In order to convert the marginal kilometres figure derived from the transport model into a £/kW signal, the expansion constant, expressed in £/MWkm, is used. The expansion constant represents the annuitised value of the transmission infrastructure capital investment required to transport 1MW over 1km. The magnitude of the expansion constant is derived from the projected cost of 400kV overhead line (OHL), including an estimate of the cost of capital, to provide for future system expansion.

In order to ensure that the cost of network expansion with different circuit types (e.g. cable) and voltages (e.g. 275kV and 132kV) is taken into account, Circuit Expansion Factors are derived. Circuit 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.

Offshore transmission networks are expected to differ from those onshore in a number of areas which mean that a different approach to that applied onshore may be required. Expansion factors onshore are weighted by historic use as described in section 2.21 of the Use of System Charging Methodology. Since there are currently no offshore transmission networks, there is no historic data to call on for the purposes of weighting the offshore transmission expansion factors by type.

Ofgem's second scoping document on offshore electricity transmission[6] proposes that the prospective OFTOs should bid for a firm revenue stream for the term of the licence or the life of the assets, and that this will then become the agreed revenue stream to be paid to the successful OFTO by the GBSO. Unlike the onshore price control regime, Ofgem would not expect to undertake regular price control reviews. As such, Ofgem would not calculate specific targets for allowances (e.g. capital expenditure, operating expenditure, tax, depreciation, cost of capital). These assumptions would be a matter for the OFTO to take into account in developing and submitting its bid.

In light of these differences, National Grid highlighted in the pre-consultation the following options to be considered:

[6] http://www.ofgem.gov.uk/Networks/Trans/Offshore/ConsultationDecisionsResponses/Documents1/070330_2ndOffshoreScopingDoc_final_am.pdf

- **Specific Approach**
  The output of a successful bid by an OFTO would be an Ofgem agreed revenue stream which would form the basis for a project specific Expansion Factor, determined so as to collect this precise revenue stream.

  Two sub-options could be applied to determine the specific Expansion Factor. The first would be to calculate the Expansion Factor so as to recover the entire revenue stream (barring connection assets) from the locational element of TNUoS. The alternative is to split the "locational" assets cost from the "non-locational" element and the Expansion Factor would fund the locational part with the remainder charged via the TNUoS residual. This approach was considered to be more complex, potentially requiring an additional tender process of justifying the split, to avoid incorrect socialisation of costs but would be more consistent with the onshore charging methodology.

- **Generic Approach**
  A number of generic Expansion Factors would be determined for various factors that significantly affect cost variance such as operating voltage or cable/ installation specification. Similar to onshore Expansion Factors, a periodic review would be required in which generic assumptions and costs would be reassessed. Historic tender bid information could be a source on which to test the assumptions.

The generic approach would have the advantage of simplicity, and would give certainty and predictability to developers. However, there would be an inherent averaging of costs, resulting in a lack of cost reflectivity. There is currently very little data on which to base generic expansion factors, and periodic reviews of the factors would also be required.

Specific locational expansion factors would be highly cost reflective, which could be particularly important given the likely material differences in costs between offshore projects. Expansion factors onshore are defined by TO, although currently the only difference is the amount of 132kV circuits that it is assumed will be uprated to 400kV. Therefore, a TO specific approach would not be inconsistent with existing onshore arrangements.

National Grid's proposal, as set out in the December 2007 consultation document, was that OFTO specific expansion factors be applied to offshore circuits in the transport model. Such expansion factors would be derived through information supplied by the OFTO, breaking down its annual revenue requirement into locational and non-locational elements. The costs of reactive compensation equipment would be included in the locational element.

The OFTO's annual locational revenue requirements for the remainder of the onshore TO price control period would be averaged, and divided by the capability and length of the offshore connection, to produce an equivalent expansion constant in £/MWkm. This would then be divided by the 400kV overhead line expansion constant to produce the OFTO specific circuit expansion factor.

It would be a requirement for the OFTO to provide a locational / non-locational split of its annual revenue requirement through the tender process and/or STC arrangements developed in the wider offshore transmission regime. National Grid suggested that, given experience of the offshore regime, it would, over time, be possible to evaluate whether offshore costs are sufficiently comparable that a move to generic expansion factors would become appropriate. It was proposed that costs identified as non locational (i.e. platforms) would be recovered through the TNUoS residual charge, consistent with the existing onshore arrangements.

The issue of reactive compensation equipment arose from the Grid Code subgroup's recommendation that the current requirements of Grid Code paragraph CC.6.3.2 specifying reactive power capability should be met by the OFTO at the Onshore Grid Entry Point. As these requirements are normally met by generators, we suggested that the costs of any reactive compensation equipment installed by the OFTO should fall on the offshore generator, rather than being socialised across all Users. It was therefore proposed that such costs would be included in the locational element of the OFTO's annual revenue requirement (as cost is proportion to cable length), and included in the calculation of the expansion factor.

A significant issue with the specific expansion factors calculated with separate locational and non-locational elements is that an additional process would be required to determine the split between the two elements. We suggested that this could be determined as part of the tender process, and would need to be incorporated into the wider development of the offshore regulatory regime. Consideration would need to be given to the potential incentive that could exist for an OFTO to allocate locational costs to the non-locational element (which would then be socialised through the residual charge), and whether this would be adequately addressed by the regulatory oversight that would be present during the tender process.

Respondents' Views

Seven respondents to the consultation expressed support for the use of a specific approach for calculating offshore expansion factors, at least initially (although one of these would have preferred the treatment of all offshore assets as connection rather than infrastructure).

A number of respondents believed that there would be a risk of significant variation between the actual costs of individual offshore connections and the charges that would be levied via a generic methodology, and that the use of generic offshore expansion factors would weaken cost reflectivity. Some of these respondents also agreed that there is currently insufficient data available to set generic offshore circuit expansion factors. However, three respondents were also supportive of a move to a generic approach, if appropriate, once sufficient knowledge and experience had been gained.

Of the three respondents not to support the use of a specific approach for calculating offshore expansion factors, one supported a generic approach and two did not express an opinion because they did not support the concept of the offshore cables being treated as infrastructure assets. The respondent supporting the generic approach accepted that, as with any averaging, there is the possibility for individual circumstances not to be reflected accurately. However, the respondent highlighted that such averaging occurs onshore, and believed that the greater stability that averaging provides makes this trade off worthwhile.

Five of the ten respondents to the consultation expressed a view on the classification of reactive compensation equipment as locational assets. Of these five, one was supportive, believing that such an approach would ensure consistency with the treatment of onshore generators. Three respondents not supporting the proposal believed that offshore generators will comply with the Grid Code at their point of connection to the transmission system, and that charging offshore generators for equipment provided to meet a requirement at a point remote from their connection points would be discriminatory. It was suggested that the transmission system would benefit from the reactive capability irrespective of the offshore generator being operational and that it would therefore be appropriate to socialise the bulk of the costs. One respondent was not clear as to why the treatment of offshore reactive compensation equipment as a locational asset was being proposed, or why this was different to onshore.

4.3 High Voltage Direct Current (HVDC)

In the pre-consultation document, National Grid highlighted that, in the future it is possible that HVDC transmission would be used offshore and, consequently, charging arrangements must be developed to facilitate this.

The HVDC cable capital costs could be recovered using either of the methodologies outlined as part of the pre-consultation for AC circuits, namely by applying either generic or project specific Expansion Factors. HVDC links differ from an AC equivalent in that as well as generic substation assets there is an additional converter station at both circuit ends. The cost of the required substation infrastructure is consequently far higher, although this results in a reduced cost per km for the cable (one of the main advantages of DC transmission). In order to ensure consistency and avoid the risk of discrimination, National Grid expressed a belief that these additional converter station costs should be included in the expansion factor calculation for DC circuits.

This could be achieved as follows:

- The specific Expansion Factor approach would allow the converter station additional cost to be simply added to the revenue stream to be recovered.

- A generic HVDC Expansion Factor approach would require a number of assumptions to be made such as circuit length and transmission capacity. This would allow the fixed unit cost of the converter stations to be apportioned into a '£/MWkm' value.

National Grid therefore proposed that the costs of offshore HVDC links would be recovered through specific expansion factors, and that these would include the costs of converter stations. The same process would be used as for AC circuits, described above, except that the DC converter stations would additionally be identified by the OFTO as a locational cost. It should be noted that whilst the converter station assets are not locationally varying, National Grid believe that they should be treated as locational because they are interactive with the cost of the associated cable (i.e. the use of HVDC means that the cable cost per km is lower than the AC equivalent).

A generic approach would again give certainty and predictability. However, the inclusion of converter station costs in a generic expansion factor would lead to projects with longer connections subsidising those with shorter connections. This would not be cost reflective, and would particularly penalise the use of HVDC for "far offshore" connections, which would be the primary use of the technology.

There is no historic data relating to offshore HVDC systems, and it seems likely that relatively few HVDC links will be constructed, even in the long term. Specific expansion factors could therefore be derived for each HVDC connection, and these would be cost reflective.

Given the significant discrepancy between converter capital cost estimates (£110/kW was suggested to OTEG by BEAMA[7] and this could be annuitised to £9.2-11.8/kW depending on assumed asset life) and the generation TNUoS residual charge (of £3.87/kW in 2007/08), National Grid believes that there is a clear case that converter costs should not be recovered through the residual charge. In that converter stations are intrinsically linked to a specific line, they are also fundamentally locational. Furthermore, they would be additional to AC assets at the relevant substations, which, it was proposed, would be funded through the TNUoS residual in any case. National Grid therefore set out its belief that the costs of offshore HVDC links should be recovered through specific expansion factors, and that these should include the costs of converter stations.

Respondents' Views

Of the ten responses to the consultation, four respondents supported the proposed approach (although one of these would have preferred the treatment of all offshore assets as connection rather than infrastructure), and a further two respondents expressed support with some qualifications. Two respondents did not support the proposal, and two did not express a view.

Respondents supporting the proposal, believed that, although converter stations are not locationally varying in practice, they should be treated as locational due to their interaction with the cost of the associated cable. Another believed that HVDC converter stations are an intrinsic part of the provision of a cable connection and should therefore be treated as "locational" assets.

Two respondents gave qualified support to the proposal, with one suggesting that there are advantages in terms of reactive capability and fault levels to the wider system of installing HVDC links, and that there is therefore an argument for allocating some of the costs of converter stations to non-locational costs. The other agreed with the rationale for the inclusion of the costs of HVDC converter stations in the derivation of specific expansion factors for offshore circuits but believed that, given no HVDC links are currently under development, it would be inappropriate and unnecessary to determine such charging arrangements now.

Of the two respondents opposed to the proposal, one questioned the logic of treating DC converter stations as locational, when AC substations are non-locational, considering that this might lead to the selection of AC in preference to DC because of the differences in charging allocation, rather than the underlying economics. The other respondent not to support the proposal questioned why DC converter station costs should be treated differently from substation assets. Although the presence of DC converter stations would allow the use of potentially cheaper DC cable, the respondent believed that this argument could be extended to onshore AC transformers, as these are necessary to allow for the lower cost per MWkm that higher voltage lines and cables provide.

4.4 Other Issues

A number of respondents raised other issues in their responses to the consultation. Many of these related to the wider regulatory regime, and to Access and Compensation. These in particular were addressed in National Grid's conclusions on

[7] British Electrotechnical and Allied Manufacturers' Association

Offshore Electricity Transmission Access and Compensation[8] published in March 2008.

Two respondents believed that charging arrangements for Embedded Transmission should be consulted on. This was not included in the consultation due to then imminent formation of the Offshore Transmission Embedded Transmission Working Group, but one respondent noted that the remit of that group did not appear to cover any material consideration of charging issues.

Another respondent commented on the issue of the applicability of the charging arrangements for offshore transmission to the Scottish Islands, welcoming the recognition that work needs to be done to progress the development of TNUoS tariffs to the islands, but believing that the significant uncertainties in the design and commercial arrangements relating to the proposed links mean that the potential application of the proposed offshore charging arrangements may be inappropriate and, in any event, would be premature at this stage.

Finally, another respondent highlighted that the connection of new offshore connections in the middle of the charging year could result in the resetting of TNUoS tariffs (with greater frequency than the current annual publication) and that this would also have implications for price controls. This issue is discussed later in this document.

5. The Ofgem Letter

Ofgem wrote to National Grid on 30 May 2008 setting out their views on the development, progression and timely delivery of the charging methodology to apply offshore.[9] Ofgem highlighted two main concerns about the basis and justification for National Grid's proposals:

- The assumption that information relating to the split between the locational and non-locational (residual) elements of the OFTO's allowed revenue would be collected as part of the tender process; and
- The basis (definition of and justification for) of the split between locational and residual charging elements.

Ofgem requested that National Grid undertake further analysis to also consider charging options offshore that may contain elements that diverge from the existing onshore approach. In particular, the following questions should be addressed:

- Whether a charging option that promotes the socialisation of offshore platform costs is appropriate for the development of offshore charging arrangements?
- If so, how would the split in locational and non-locational revenue be accommodated so as not to lead to a distortion in the tender process?

[8] http://www.nationalgrid.com/NR/rdonlyres/9A9C1C08-8801-46FF-97C5-8DF4E733AAB1/24366/OffshoreElectricityTransmissionAccessandCompensati.pdf
[9] http://www.nationalgrid.com/NR/rdonlyres/08880813-81D6-45B9-8867-9DB13951FA42/26376/3052008LettertoHeddRobertsFINAL.pdf

- What is the financial significance of not socialising offshore platform costs and platform assets through the residual charge (e.g. adopting an approach to include offshore substation costs within the locational element of the TNUoS charge)?
- What is the financial effect of all offshore charging options on the onshore charging base and onshore tariffs?
- Do any of the charging options adversely impact the ability of all parties to realise the economic benefits in sharing offshore assets?
- What arrangements are required to determine the split between infrastructure and connection revenue to determine connection charges?
- What interaction is envisaged between GBECM-11 (Charging Arrangements for Generator Local Assets) and GBECM-08 and the possible application of a local charging approach (identical to the approach that is envisaged to apply to "local" assets onshore) to offshore platform assets?
- What methodology is envisaged for deriving a TNUoS tariff for "partially" redundant and single circuit offshore connection designs and for "discounting" the tariff to be paid by the offshore generator for such connections?

Ofgem also requested that National Grid gave further consideration to the development of alternative mechanisms to facilitate the proposed split of locational and non-locational revenue, and how it was proposed that the required asset information be gathered outside of the tender process.

Finally, Ofgem stated an expectation that National Grid would submit a charging methodology modification proposal to Ofgem in December 2008 and no later than 1 January 2009, to allow the Authority to make a decision before 1 April 2009.

National Grid has carefully considered the issues raised by Ofgem in its letter. The proposals contained within this consultation reflect the outcome of this consideration, and we believe that we have addressed the Ofgem's two main concerns relating to the split of the OFTO's allowed revenue and the split between locational and residual charging elements. Additionally, in establishing the proposals contained within this consultation, National Grid has considered the specific questions contained within Ofgem's letter.

6. Proposed Modification

National Grid's revised proposals are set out in this section. These relate to each of the connection / use of system boundary, expansion factors and HVDC. (It should, however, be noted that National Grid's proposal in respect of the connection / use of system boundary continues to be to make no modification to the existing onshore arrangements.) The sections relating to expansion factors additionally include proposals relating to locational security factors and substation tariffs.

Our rationale and the justification for the proposals, together with the further analysis requested by Ofgem, is included as section 6.2.

6.1 Description of Proposed Modification

National Grid is proposing to modify the Use of System Charging Methodology to include additional processes for deriving Expansion Factors to apply offshore for AC and DC circuits, project specific security factors and substation tariffs. The proposal is described in more detail below, including details of where our proposals are the same, or have changed since the original consultation. Proposed drafting of the required modifications to the Statement of the Use of System Charging Methodology is included as Appendix 1.

6.1.1 Offshore Connection / Use of System Boundary

National Grid's recommendations in this area have not changed since the original consultation.

Therefore, National Grid continues to propose that the offshore connection / use of system boundary would be at the offshore substation LV busbar (the disconnector on the busbar side of the circuit breaker on the outgoing windfarm circuit - option 1 in the pre-consultation). As this is consistent with the current onshore arrangements, no changes to the Statement of the Connection Charging Methodology will be required.

6.1.2 Offshore Expansion Factors, Security Factors and Substation Tariffs

Expansion Factors

National Grid's recommendations in this area have not changed since the original consultation.

Therefore, National Grid continues to propose that OFTO specific circuit expansion factors be applied to the transport model. Such expansion factors would be derived by the GBSO deriving a breakdown of the OFTO annual revenue requirement apportioned on the basis of the cost of installed assets, through a process to be established in the STC, therefore eliminating the requirement for an additional tender process.

The Offshore Grid Code subgroup recommended that reactive capability be provided by the OFTO. It is expected that the obligation to provide this capability will be contained within the STC. Therefore, we expect that a potential OFTO will include the costs of reactive compensation equipment in its submission of revenue requirements as part of its tender and, reactive compensation equipment would be included in the calculation of the expansion factors. Operationally, National Grid intends to utilise this reactive capability in the same way that it would any other TO's reactive equipment. An onshore generator typically provides its required reactive capability and is able to compete to sell reactive support to the System Operator. Consequently, further consideration is required in ensuring the appropriate treatment of OFTO provided, but generator funded, reactive compensation assets.

Where additional capacity is constructed than is required by a generator or more than one generator is connected to an OFTO network, it will be necessary apportion the OFTO costs. Consistent with onshore the cost of additional circuit capacity is funded via the residual. For multiple generator circuit use, charges would be pro-rated by the TEC of all the offshore generators connected to that offshore network. (A number of CUSC amendments currently under development to reform the transmission access arrangements propose the introduction of a new capacity term, the Local Capacity

Nomination (LCN). It is envisaged that, if approved, the apportionment methodology would be modified to refer to LCN rather than TEC.)

Except in the first year of connection, the OFTO revenue associated with cables and reactive compensation over the remainder of the onshore TO price control period would be averaged, and divided by the capability and length of the offshore connection, to produce an equivalent expansion constant in £/MWkm. This would then be divided by the 400kV overhead line expansion constant to produce the OFTO specific circuit expansion factor.

Given that it is unlikely that the offshore connection will be commissioned on a 1 April, in the first year a separate expansion factor will be calculated using the part year value of revenues. The offshore generator would, as onshore, pay charges from the time of connection, but these would recover the correct, lower revenue requirement of the OFTO for that year. Consequently, it can be assumed that the monthly charge levied on an offshore generator would remain broadly the same between the first and second charging years.

Security Factors

National Grid is making new recommendations in this area.

It is proposed that specific circuit security factors would be also calculated for each offshore connection, comparing the rating of the cable with the capacity of the power station(s) connected by it. In the event the connection was via a single cable, the security factor would be 1.0.

If the connection was via multiple cables, a ratio between the capability of the cables and the capacity of the generator(s) would be calculated, to a maximum of 1.8 (the wider locational security factor). For example, a 400MW generator connected by two cables with a combined capability of 500MW would result in a specific security factor of 1.25. Upon the connection of additional generation at an offshore node and/or the construction of additional offshore circuits, the circuit security factor would be recalculated.

Substation Tariffs

National Grid is making new recommendations in this area.

It is further proposed that substation tariffs would be calculated for, and levied on, each offshore generator.

Using the same proposed STC mechanism through which OFTOs would report to National Grid (as GBSO) the costs of cables and reactive compensation equipment to calculate expansion factors, OFTOs would also report the costs and capability of transformers, switchgear and the offshore platform. This would be used by National Grid to derive the OFTO's revenue associated with each asset component and each averaged over the price control period.

The substation tariff will be sum of separate £/kW components calculated for transformers, switchgear and platform by dividing the relevant asset revenue by the relevant asset capability. For offshore platforms, the capability would be higher of the capability of the transformers and switchgear.

Additionally, to ensure both offshore and onshore charges are on the same basis an adjustment equivalent to the average cost of civil engineering costs for onshore substations would be deducted. Consequently, the offshore substation tariff will reflect the incremental cost rather than including asset costs that are socialised onshore. The exact level of the discount has yet to be finalised, but initial analysis of a number of recent projects produced an indicative range of £0.2-0.5/kW.

The offshore generator pays a substation local tariff for the offshore connection substation only and therefore the only contribution to the cost of all other substations will be through the residual element of TNUoS.

The substation tariff would be levied on all generators connected to that OFTO connection by multiplying by each generator's TEC. If GBECM-11 is not vetoed by the Authority a substation tariff will be levied on all onshore transmission connected generators.

6.1.3 HVDC

National Grid's recommendations in this area have not changed since the original consultation.

Therefore, National Grid continues to propose that the costs of offshore HVDC links would be recovered through specific expansion factors, and that these would include the costs of converter stations. The same process would be used as for AC circuits, described above, except that the DC converter stations would additionally be identified by the OFTO as a cost relating to the offshore cable.

6.1.4 Embedded Transmission

National Grid is making new recommendations in this area.

For embedded transmission, it will be necessary for National Grid as GBSO to pass through charges levied on it by Distribution Network Owners (DNOs). It is proposed that a new type of Use of System charge, Embedded Transmission Use of System charges ("ETUoS"), be established in the Use of System Charging Methodology. Through this mechanism, DNO charges would then be passed through directly by National Grid to the relevant offshore generators. This ensures consistency with onshore embedded generation who are directly responsible for any charges levied by the DNO resulting from their connection.

Where more than one generator is connected to an OFTO network, it will be necessary to apportion the passed through DNO charges. It is therefore proposed that such charges would be pro-rated by the TEC of all the offshore generators connected to that offshore network. (A number of CUSC amendments currently under development to reform the transmission access arrangements propose the introduction of a new capacity term, the Local Capacity Nomination (LCN). It is envisaged that, if approved, the apportionment methodology for ETUoS would be modified to refer to LCN rather than TEC.)

More background on this proposal is given in section 6.2.4.

6.1.5 Generation Zoning

National Grid is making a new recommendation which results from the final proposals made through GBECM-11, Generator Local Charging.

Under GBECM-11, a User's marginal cost (or locational signal) is subdivided into a 'local' and a 'wider' component. The local component is charged via a nodal specific tariff, whereas the wider component remains as a zonal average tariff. Consistent with the existing methodology, under GBECM-11 the zonal tariff is to be calculated from a volume weighted average of the marginal cost for all generation within a zone, although the local marginal cost component would be discounted to avoid double charging.

Within the existing methodology, generation zonal boundaries are determined with a set of zoning criteria, one of which is that zones should only contain nodes whose marginal costs would lead to a maximum tariff spread of £2.00/kW. National Grid is proposing to determine zonal boundaries from the 'wider' component of generators marginal cost, after the removal of the 'local' circuit flow cost. For the avoidance of doubt, an offshore generator would therefore be in the same TNUoS generation zone as the first onshore MITS substation to which it connects.

6.2 Justification for Proposed Modification

The modification is required because there are currently no charging arrangements for networks forming part of the GB Transmission System other than those of the existing three licensees. The modification would therefore facilitate the inclusion of licensed offshore networks by introducing arrangements to recover the costs of such networks through TNUoS and connection charges. The rationale for our specific proposals, together with the further analysis requested by Ofgem, is set out in the sub-sections below.

6.2.1 Offshore Connection / Use of System Boundary

National Grid's recommendations in this area have not changed since the original consultation, therefore the justification remains the same and is outlined below.

National Grid has previously highlighted that applying the connection / use of system boundary at the offshore substation LV busbar would be consistent with arrangements onshore. This was identified as option 1 in the pre-consultation.

Offshore substations and cables could potentially be shared, with a number of different Users connecting to an offshore substation. Although this has not been observed in the projects connected to date under the interim merchant regime, proponents of the enduring offshore transmission regime point to the increased co-ordination that would result from the new arrangements as better facilitating sharing.

Adoption of either of the other options previously highlighted would therefore represent a departure from the existing "plugs" shallow connection charging regime onshore, in that the costs of potentially shareable assets would be recovered through connection charges. Option 3, where the connection charging boundary would be at the onshore connection point, would further contravene the existing principle that circuits greater than 2km in length are treated as infrastructure, even if they are not potentially shareable.

It has previously been highlighted that offshore transmission substations differ from those onshore in that they are housed on expensive platforms and that the costs of offshore cables may also be (but need not be) more expensive than those onshore. If these relatively expensive offshore connections were charged through TNUoS, due to the requirement to maintain an overall split in revenue recovery of 73%/27%

between demand and generation, tariffs faced by onshore generation and demand customers could be significantly affected. Treating all offshore networks as connection assets would leave onshore tariffs unaffected.

However, in order to implement such a change, a charging methodology for shared connection assets between multiple users would be required. This would expose users to the actions of other generators, a key reason for the move to the “plugs” shallow regime onshore. Offshore generators would also be fully exposed to costs resulting from wider OFTO decisions to provide additional assets for future connectees, as the costs of these additional assets, including substation assets, would be included in the connection charge.

Consistent with our proposals for Charging Arrangements for Generator Local Assets, National Grid believes that it would be more appropriate to reflect the costs of substation assets through TNUoS charges, including the targeting of costs, as this would protect generators both from the actions of other generators and from the over-provision of assets by OFTOs. Our proposals in this area are discussed in the next sub-section.

As our proposal that the offshore connection / use of system boundary would be at the offshore substation LV busbar is consistent with the current onshore arrangements, no changes to the Statement of the Connection Charging Methodology will be required.

6.2.2 Offshore Expansion Factors, Security Factors and Substation Tariffs

Given the adoption of a connection / use of system boundary at the offshore substation LV busbar, both offshore cables and substations will be treated as infrastructure assets.

National Grid has previously set out two approaches for including the costs of cables in the derivation of TNUoS charges. The generic approach would have the advantage of simplicity, and would give certainty and predictability to developers. However, there would be an inherent averaging of costs, resulting in a lack of cost reflectivity. There is currently very little data on which to base generic expansion factors, and periodic reviews of the factors would also be required.

For these reasons, we proposed that a specific approach should be used. Specific locational expansion factors would be highly cost reflective, which could be particularly important given the likely material differences in costs between offshore projects. Expansion factors onshore are defined by TO, although currently the only difference is the amount of 132kV circuits that it is assumed will be uprated to 400kV. Therefore, a TO specific approach would not be inconsistent with the onshore arrangements.

In addition to the costs of cables, the specific locational expansion factors would also include the costs of reactive compensation equipment. As the current requirements of Grid Code paragraph CC.6.3.2 specifying reactive power capability would be met for offshore generators by the OFTO at the Onshore Grid Entry Point, as opposed to the generator itself onshore, National Grid believe that the costs of any reactive compensation equipment installed by the OFTO should fall on the offshore generator. An onshore generator would be required to provide reactive plant so as to meet the reactive compensation requirements within the Grid Code.

In addition to calculating specific locational expansion factors, it is also proposed, to calculate specific locational security factors. The security factor is used to take account of increased circuit flows following circuit outages. If the connection was by a single cable, a locational security factor of 1.0, as opposed to the global locational security factor of 1.8, would be applied to the offshore cable. For connections via multiple cables, nodal specific factors would be calculated by dividing the capability of the cables by the capacity of the generators connected by them. This would be capped at 1.8.

This factor would ensure that offshore charges accurately reflect the lower costs associated with the lower security standards applied offshore. Additionally, the capping would protect generators from investment made by OFTOs for strategic purposes.

A change in our proposals, since the December 2007 consultation, is the proposed introduction of substation tariffs. This follows publication of our GB ECM-11 proposals which include a substation local tariff. One of the underlying principles of the offshore charging regime is that offshore arrangements should not differ from those onshore without good reason, and our revised offshore proposals therefore reflect onshore developments in the interim.

The substation local tariff targets the incremental non locational asset cost of the generator's local transmission substation. Although potentially sharable, offshore substation assets will only be used by offshore generators (as opposed to demand or being installed for wider system reasons). Therefore, in such circumstances, consistent with the proposed treatment of remote substations onshore, it is appropriate that costs should be targeted at the relevant generators, rather than being socialised over all users.

However, by reflecting these costs through an infrastructure, rather than connection, charge, generators are protected both from the actions of other generators and from OFTO investment made for wider strategic reasons (in that the generator only pays for that proportion of the assets that it is using). The cost of the capacity that is not used by the generator is recovered through the TNUoS residual, as is consistent with the onshore arrangements. The application of a local security factor ensures all feasible capacity that could be used by a generator, including during outage conditions, is reflected into the TNUoS tariff and therefore the generator has no incentive to make decisions that would lead to an increase in socialised costs.

The onshore substation local tariff, as proposed within GB ECM-11, targets the incremental cost of non locational primary transmission asset onto a generator but does not include generic costs such as civil works. Given the very high costs associated with offshore platforms (£5m plus £20/kVA has been suggested), National Grid believe that an alternative approach offshore as compared to onshore is justified, in that the incremental costs of offshore platforms would be reflected through a specific offshore platform tariff. However, an adjustment equivalent to the average cost of onshore civil engineering costs would ensure the offshore generators would only pay the incremental cost of being located offshore as opposed to onshore. As consistent with the cost of onshore civil works, this offshore adjustment is therefore funded through the TNUoS residual element.

In order to calculate the offshore substation tariff and expansion factors specific information would be required from the OFTO as part of the OFTO tender submission and/or subsequent STC processes. The information would include a breakdown of cable, platform, transformer, reactive compensation and switchgear costs.

By charging substation, as well as cable assets, on a cost reflective basis to the relevant generator(s), the incentive for any misallocation of costs by the OFTO will be much reduced. By reflecting the difference between offshore platform costs and onshore civil engineering costs through an adjustment based on onshore costs and determined by the GBSO, there would be no opportunity for OFTOs to influence this element.

6.2.3 HVDC

National Grid's recommendations in this area have not changed since the original consultation, therefore the justification remains the same and is outlined below.

National Grid is not currently aware of any proposals to use HVDC technology to connect offshore generators, although it is likely that HVDC will be used in the future if windfarms are located further away from the coast.

National Grid therefore believes that the costs of offshore HVDC links should be recovered through specific expansion factors, and that these should include the costs of converter stations.

6.2.4 Embedded Transmission

An issue not previously covered was that of offshore transmission networks connecting to onshore distribution systems. This has arisen because, under the offshore transmission regime, 132kV will be a transmission voltage offshore. However, in England and Wales, 132kV is a distribution, rather than transmission, voltage. Therefore, in some instances, networks constructed by OFTOs will connect to 132kV distribution networks onshore. The existing regulatory and commercial frameworks do not cater explicitly for such arrangements, and this issue has become known as "embedded transmission". National Grid has carefully considered the appropriate mechanism for dealing with these arrangements.

Regulatory Framework

The Joint Ofgem/BERR Policy Statement on Offshore Electricity Transmission ("the July 2007 document") summarised the current distribution connection charging and use of system charging arrangements, and noted "that there is flexibility within the distribution charging arrangements".[10] However, it also stated that Ofgem/BERR "consider that arrangements for embedded transmission connections should be consistent with arrangements for distribution connected large power stations".[11] The document further set out that it would be the GBSO (rather than the OFTO or generator) that entered into an agreement for connection to and use of the distribution system.

DNOs would therefore levy charges on the GBSO in a similar manner to existing distribution connected large power stations. The July 2007 document further stated that "the GBSO will reflect the charges for connection to and use of the distribution system in its charges to the offshore generator". This is an evolution in the development of the regime from the earlier second scoping document, in which it was stated that the GBSO could be "required to pay in full for any works it requires the

[10] "Offshore Electricity Transmission – A Joint Ofgem/BERR Policy Statement", July 2007, 7.10 – 7.12
[11] Ibid, 7.8

DNO to undertake on its network. These costs could then be funded by the OFTO and recovered through the ongoing payments the GBSO to the OFTO".[12] This highlights that, even if the GBSO passed the DNO charges straight through to the OFTO, they would ultimately be recovered from generators in a cost reflective manner in the same way as the rest of the OFTO's costs.

Charging and Revenue Options

In determining how the charges levied on National Grid by DNOs should be treated, there are two high level issues to be considered:

- The regulatory treatment of the revenue; and
- To whom the charge should be passed through.

There are two main options for the regulatory treatment of the revenue: either to treat it as an Excluded Service[13], or to include it in National Grid's TO revenue restriction. National Grid believe the most appropriate mechanism for giving effect to the latter option would be to add an additional term to the Pass Through (PT) Items defined in Special Condition D4 of National Grid's Electricity Transmission licence, in the same way that the TSP and TSH terms allow the pass through of charges levied on National Grid by SP Transmission and Scottish Hydro-Electric Transmission (similar arrangements will be required to allow the pass through of charges levied on National Grid by OFTOs) If the revenue was instead to be classed as an Excluded Service, we believe the definition of excluded services in Special Condition D10 would require amendment

There are also two main alternatives as to whom the charges should be passed to: Offshore generators or OFTOs. As Transmission Owners are not party to the CUSC, any methodology to levy charges on OFTOs would need to be given effect by the STC.

From the two high level issues described above, National Grid developed and evaluated five more detailed options:

1. **Charge all Users by socialising through the residual element of TNUoS** – This is conceptually the simplest option, in that no changes to the charging methodology would be required. By adding an additional term to the TO revenue restriction, the amount to be recovered would be increased. With no other changes, this would increase the residual element of TNUoS, and consequently be smeared across all Users (73% to demand and 27% to generators). However, this option would lack any element of cost reflectivity.

2. **Charge offshore generators through the locational element of TNUoS** – As above, the additional revenue would be included in the TO revenue restriction and recovered through TNUoS. However, in this option the costs would be targeted at offshore generators through the locational element of TNUoS. This could be given effect by changing the charging methodology to include costs relating to DNO charges in the offshore circuit expansion factor or by modelling the DNO network in the DCLF transport model, although would be complex and potentially problematic.

3. **Charge offshore generators through a new type of Use of System charge** – In this option, the revenue would again be included in the TO

[12] "Offshore Electricity Transmission – Second Scoping Document", Ofgem, March 2007, 4.9
[13] Excluded Services are defined within Special Condition D10 of NGET's Transmission Licence

revenue restriction, but would instead be recovered from Offshore Generators through a new type of Use of System charge (Embedded Transmission Use of System or ETUoS). National Grid would pass DNO charges straight through to offshore generators, although rules to apportion charges where more than one generator is connected to an OFTO network would be required. It is proposed that this be done by pro-rating by TEC (although, as noted in section 6.1.4, this may subsequently be amended to LCN). This option would be cost reflective, and would allow for the establishment of a bespoke charging timetable, separate from TNUoS, that would more effectively mesh with that of DNOs. (This would require ETUoS to be excluded from the existing payment terms set out in paragraph 6.6 of the CUSC.)

4. **Charge offshore generators as an excluded service** – This would be very similar to option 3, above, in that charges would be passed straight through to offshore generators. However, in this option the revenue would be treated as an excluded service, and would sit outside of the TO revenue restriction. An entirely new type of charge would be created, and a minor licence change would be required to bring this into the scope of the CUSC governance. A separate charging methodology statement would be produced, and this would include the apportionment of charges by TEC.

5. **Charge OFTOs as an excluded service** – In this option, the revenue would be treated as an excluded service, and would be recovered from OFTOs through a new charging mechanism, under STC governance. The intent would be for OFTOs to then recover these costs as a locational element of the TO general system charges levied on the GBSO. Costs would therefore ultimately be borne by generators in a cost reflective manner. In addition to this ultimate cost reflectivity, a bespoke charging timetable would be created, and there would be no requirement for apportionment rules. However, this option would result in very convoluted cash flows, and it is not clear that the OFTO revenue restriction would facilitate the pass through of the charges to be levied.

Option 1, socialising the revenue, would not be cost reflective, and would therefore lead to inappropriate incentives on offshore generators to connect via distribution. Option 2, including in the locational element of TNUoS, would be complex, and would not allow for a back to back charging timetable. Option 4, charging offshore generators as an excluded service, is very similar to Option 3, but with arguably less robust governance. Finally, option 5, charging OFTOs may not be practical, as the OFTO's revenue restriction my not facilitate the pass through of charges. It may also be necessary to pass through upfront capital payments, and this might happen before the OFTO has been appointed. Options 3, 4 and 5 arguably introduce an inconsistency in how the cost of onshore transmission or distribution reinforcements are charged, which could effect generator locational decisions.

National Grid's current proposal is therefore option 3, to charge offshore generators through a new type of Use of System charge.

National Grid believes that a new type of Use of System charge will provide the transparency, cost-reflectivity and flexibility required to charge all the relevant DNO charges[14] that are levied on the GBSO through to the offshore generator.

[14] These may include upfront charges, capital contributions as well as the ongoing Distribution Generation Use of System charges.

Additionally, as this represents a new area where National Grid is passing through charges levied on it by DNOs, and is therefore different from other TNUoS charges, a separate use of system charge is justified. The Charging Methodology covers all transmission network services, except excluded services and balancing services and therefore National Grid believes introducing embedded transmission charges does not require the Transmission Licence to be changed in order to establish an additional, discrete charging methodology.

National Grid expects that it will enter into a Construction Agreement with a DNO to facilitate the connection of the embedded transmission system, and National Grid intends to reflect through the terms of this Construction Agreement in the Bilateral Connection Agreement it enters into with the offshore generator (this will be put in place via an Agreement to Vary the initial Bilateral Connection Agreement).

Given the multiple parties and multiple industry documents involved, we believe that the importance of aligning the charging processes and timetable should not be underestimated. Any changes of the charges levied by the DNO, will directly flow through to the connected Offshore generators and therefore additional risk will not be socialised across all users.

As this is the first time on which we have consulted on this issue, National Grid particularly welcomes views from the industry on this subject.

Other Issues Arising From Embedded Transmission

The existing TNUoS transport model assumes a contiguous network, so a minor addition to methodology will be required to accommodate “islanded” sections of transmission (i.e. those isolated from the rest of the transmission system by a distribution network). This will be a relatively simple matter of multiplying the length of the offshore transmission network by the expansion factor, and adding this to the relevant onshore marginal cost (essentially ignoring the disconnect between the two transmission networks). The consequential additions to the Statement of the Use of System Charging Methodology are shown in appendix 1.

“Embedded Benefits”

A further issue resulting from embedded transmission relates to “embedded benefits”. Currently offshore generators that are less than 100MW and connected at 132kV to an onshore distribution system will pay negative (i.e. will be paid) BSUoS and Demand TNUoS charges (either directly if registered in Central Volume Allocation or through the relevant Supplier if registered in Supplier Volume Allocation).

Once the offshore transmission regime goes live, the 132kV network offshore will be classed as part of the Transmission System, and such generators will become liable to pay positive BSUoS and Generation TNUoS charges. This is inherent in classifying 132kV connections as “transmission”, and is consistent with onshore arrangements. However, such generators would be eligible for discounted Generation TNUoS charges (by one-quarter of the total TNUoS residual charge) if the Licence Condition C13 “small generators discount scheme” were to be extended such that it were still in force following go-live of the offshore transmission regime.

However, through discussion at the Transmission Charging Methodologies Forum, it has been identified that some industry parties believe that such arrangements would not be appropriate[15]. The following strawman was put forward for consideration by an industry party:

Embedded Benefits Strawman

In this model, embedded power stations of 100MW or above would be treated as transmission connected, which is consistent with equivalent onshore embedded generators. However, for Licence Exempt (or Exemptible) Embedded Transmission connected projects the arrangements would be different and more akin to those for exempt onshore distribution connected generators. The only difference is that the generator is connected by a discrete amount of offshore transmission voltage network before being connected into the distribution network.

Under this option an OFTO would still be appointed by the competitive tender process. Instead of ongoing TNUoS charges, the generator would pay a deep connection charge for the offshore transmission assets which would also include the onshore distribution system connection costs. The deep connection charge could be levied either as upfront capital payments or remunerated over the assumed life of the assets.

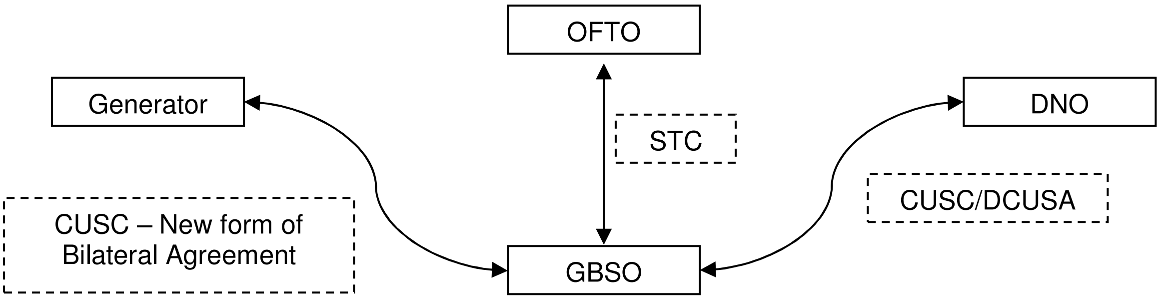
The rationale for the deep connection charge is that would put the Licence Exempt Embedded Transmission project in the same position as an onshore embedded generation project. The generator would pay for its direct offshore transmission assets to connect to the Distribution network and subsequently pay use of system charges for the wider Distribution system costs. This option would avoid socialising the offshore Transmission costs across the wider charging base.

The generator would be afforded a right to remain connected and use the offshore transmission assets but they would not be granted an explicit CEC or TEC. The generator would be afforded a right to use the Distribution system. However the Licence Exempt Embedded Transmission projects use of system rights would end at the Distribution system. In other words they would be deemed to net against local demand in the distribution system as is the case with other embedded generators. The generators concerned would therefore not fully benefit from being connected to the wider transmission network and would be fully exposed to faults on the distribution system which prevented them exporting power, as with any other embedded generator.

The DNO could levy the GDUoS charges against the OFTO who in turn passes these through to the generator. The generator would not receive compensation for loss of wider transmission access, but would be able to claim under an agreed OFTO incentive/compensation package for non-performance or failure to meet licence standards of service for the offshore element of its connection. The generator may also be able to receive appropriate compensation for loss of access from the DNO under the DNO charging arrangements albeit through the OFTO.

The relationships between the three parties could be managed via the GBSO. The GBSO would offer the Generator a new type of bilateral agreement under the CUSC. This would cover connection to the OFTO's network, which reflects the LEEMPS technical requirements, the right to remain connected to the OFTO network, use of the DNO network, appropriate compensation and the OFTO and DNO's charges.
The GBSO model for this option could look like:

[15] http://www.nationalgrid.com/NR/rdonlyres/3F26A596-B935-41CA-9405-74429133D3E5/20852/EmbeddedGenerationOct2007TCMFfinal.pdf



This would require changes to the GBSO charging methodology to reflect the OFTO deep connection charging methodology for Licence Exempt Embedded Transmission Connections. The DNO charging methodology may also need to be updated to reflect the rights of a Licence Exempt Embedded Transmission Generator to use the Distribution network. Appropriate changes to the CUSC and DCUSA would also be required to capture the new class of generator.
Alternatively a tripartite agreement between the DNO/OFTO/Generator or bilateral agreements between the DNO/OFTO and the OFTO/Generator, such that all necessary technical, interface, use of system rights and charging arrangements are backed off appropriately, could be considered.

National Grid's View

We consider that the levying of transmission charges on exemptible power stations offshore is inherent in classifying 132kV connections as "transmission", and is consistent with onshore arrangements. This situation already occurs in Scotland, where such power stations are connected to the transmission network at 132kV. These generators are eligible for discounted Generation TNUoS charges (by one-quarter of the total TNUoS residual charge) via the Licence Condition C13 "small generators discount scheme", which sits outside of the governance of the Use of System Charging methodology.

We therefore believe that any treatment of exemptible power stations offshore is a wider regulatory issue, and that any alternative arrangements would therefore not best be given effect in the Use of System Charging Methodology. However, we welcome the views of the industry on this issue.

6.2.5 Generation Zoning

Performing generation zoning on a wider nodal marginal cost basis ensures the same principle is applied both offshore and onshore, namely that nodes with similar marginal cost are grouped into a zone, increasing tariff stability and predictability.

National Grid believes this clarification of the zoning criteria should be applied across the GB network for both offshore and onshore generation nodes. That withstanding, the impact of this change is not anticipated to result in any changes to the zonal boundaries for the charging year commencing 1 April 2009.

6.3 Impact on Other Industry Documents

As noted above, an additional process will be required whereby OFTOs would provide their annual revenue requirement broken down into a number of elements (cables, reactive compensation, transformers, switchgear and platform costs). This would most likely be specified in the STC.

The proposal relating to Embedded Transmission would require changes to National Grid's transmission licence and to the CUSC, as described above. Additionally, as this proposal would work most effectively if National Grid had advance notice of the charges to be levied on it, we consider it may be appropriate to place some such obligation on DNOs, either in the CUSC or in the Distribution Connection and Use of System Agreement (DCUSA).

National Grid recommends that the changes to codes and licences required to facilitate the proposals contained within this consultation should be progressed as part of the Ofgem/DECC project to implement the offshore transmission regime.

National Grid welcomes the views of the industry on whether the proposed modification would require any further amendments to any industry documents.

6.4 Implementation Date

The implementation date for the proposed change will be 28 days after furnishing the conclusions report to the Authority, subject to non-veto (or 3 months if the Authority decides to undertake an Impact Assessment). National Grid currently anticipates that the conclusions report would be issued in November 2008. However, the modification would have no practical effect (as there would be no licensed offshore transmission systems) until the offshore transmission regime reaches "go-live". This is currently planned for April 2010.

7. Responses to this Consultation

Comments and views are invited on the issues raised in this consultation document. To ensure that your comments and views are considered as part of National Grid's Conclusions Report to the Authority, responses must be received by close of business on **24th November 2008**.

If you wish to provide comments on this 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 Ireland on 01926 656152.

Appendix 1: Proposed drafting of the Statement of the Use of System Charging Methodology

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

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

The Transport Model

Model Inputs

2.2 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

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
- Identification of a reference node

2.4 For 2008/9, the nodal generation data for the transport model will be derived from the GB Seven Year Statement, which will contain the contracted generation Transmission Entry Capacity (TEC) and include all notification of changes in generating capacity received by 23 December 2007. Thereafter, for charging year "t", the nodal TEC figure at each node will be based on the Applicable Value for year "t" in the GB Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs in the GB Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2009/10 charges, the nodal generation data is based on the forecast for 2009/10 in the 2008 GB

Seven Year Statement plus any data included in the quarterly updates to October 2008.

2.5 Nodal demand data for the transport model for 2008/9 will initially be based on GSP demand that Users have forecast to occur at the National Grid Peak Average Cold Spell (ACS) demand. Thereafter, for year "t", data will be based upon the GSP demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

2.6 Transmission circuit data for charging year 2008/9 will initially be based on data taken from National Grid's April 2007 GB Seven Year Statement complemented with the October updates. Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April GB Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the GB Seven Year Statement, National Grid will use the best information available.

2.7 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

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. 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.

2.9 A reference node is required as a basis point for the calculation of marginal costs. It determines the magnitude of the marginal costs but not the relativity. For example, if the reference point were put in the North of Scotland, all nodal generation marginal costs would likely be negative. Conversely, if the reference point were defined at Land's End, all nodal generation marginal costs would be positive. However, the relativity of costs between nodes would stay the same. For information purposes the reference node for 2008/9 is West Burton 400kV (WBUR40).

Model Outputs

2.10 The transport model takes the inputs described above and firstly scales the nodal generation capacity uniformly such that total national generation (sum of contracted TECs) equals total national ACS Demand. The model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal demand using the scaled nodal generation, assuming every circuit has infinite capacity.

Then it calculates the resultant total network MWkm, using the relevant circuit expansion factors as appropriate.

2.11 Using this baseline network, the model calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (demand) at the reference node, the increase or decrease in total MWkm of the whole network. Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a marginal km cost for generation at each node. The marginal km cost for demand at each node is then equal and opposite to, the nodal marginal km for generation. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

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

Calculation of zonal marginal km

2.13 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 2.17. The number of generation zones set for 2008/9 is 20.

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

2.15 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:

$$WNMkm_j = \frac{NMkm_j * Gen_j}{\sum_{j \in Gi} Gen_j}$$

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

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

2.16 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

2.17 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 wider 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.

2.18 The process behind the criteria in 2.17 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. 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.

2.19 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.

2.20 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 £/kW Tariff

2.21 The zonal marginal km are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below).

The Expansion Constant

2.24 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.

2.25 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 2.42, 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 2.47.

2.26 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 onshore 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.

2.27 For each circuit type and voltage used onshore. 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 onshore circuit expansion factors discussed in 2.35. 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.

2.28 The table below shows the first stage in calculating the onshore 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.

2.29 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:

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

2.30 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.

2.31 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.

2.32 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**

2.33 This process is carried out for each voltage onshore, 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 onshore expansion factors. The process used to derive circuit expansion factors for offshore TO (OFTO) networks is described in ●.

2.34 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore 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.

Onshore Circuit Expansion Factors

2.35 Base onshore 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.

2.34 In calculating the onshore 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.

2.35 The 132kV onshore 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.

2.36 The 275kV onshore 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.

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

2.38 The TO specific onshore 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

Offshore Circuit Expansion Factors

2.39 Offshore expansion factors (£/MWkm) are derived from information provided by OFTOs for each offshore circuit. Offshore expansion factors are OFTO and circuit specific. Each OFTO will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the OFTO's reactive compensation equipment.

2.40 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div \text{Onshore 400kV OHL Expansion Constant}$$

Where:

CRevOFTO1 = The offshore circuit revenue in £ for Year 1

L = The total circuit length in km of the offshore circuit

CircRat = The continuous rating of the offshore circuit

2.41 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div \text{Onshore 400kV OHL Expansion Constant}$$

Where:

AvCRevOFTO = The annual offshore circuit revenue averaged over the remaining years of the onshore GBSO price control

L = The total circuit length in km of the offshore circuit

CircRat = The continuous rating of the offshore circuit

2.42 Prevailing OFTO specific circuit expansion factors will be published in this Statement. These shall be re-calculated each price control when then onshore expansion constants are revisited.

The Locational Onshore Security Factor

2.39 The locational onshore 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.

2.40 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[16].

2.43 The locational onshore 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.

The Offshore Security Factor

2.44 A circuit specific offshore security factor (OffSF) will be calculated for each offshore connection using the following methodology:

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

$$OffSF = \frac{CircRat}{\sum_k Gen_k}$$

Where:

k = the generation connected to the offshore network

2.45 The offshore security factor for single circuits will be 1.0 and for multiple circuit connections will be capped at the locational security factor, derived as 1.8 for 2008/9.

Initial Transport Tariff

2.42 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

2.43 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

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

2.44 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.

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

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)

2.45 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:

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

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

Where C is set such that

$$CTRR_D = p(CTRR_G + CTRR_D)$$

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)

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

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

So that

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

Offshore substation local tariff

2.47 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of a transformer, switchgear, and platform components.

2.48 Each tariff component, expressed in £/kW, shall be the ratio of the OFTO revenue (£) and rating associated with the transformers, switchgear, or platform (kW) at each offshore substation. In the case of the platform component, the relevant rating shall be the higher of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the OFTO revenue associated with each tariff component shall be averaged over the remaining years of the GBSO price control.

2.49 A discount of [£0.2/kW – £0.5/kW] shall be provided to the offshore substation tariff, to reflect the average cost of civil engineering for onshore substations.

2.50 Offshore substation tariffs shall be inflated by RPI each year and reviewed every price control period.

2.51 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\text{All offshore substations}} \left(SLT_k \times \sum_k Gen_k \right)$$

Where:

SLTk = the offshore substation tariff for substation k

Genk = the generation connected to offshore substation k

Renumber subsequent paras

The Residual Tariff

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

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

Where

TRR_t = TNUoS Revenue Recovery target for year t

R_t = Forecast Revenue allowed under National Grid's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition AA5A of National Grid's Transmission Licence.

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

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

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

2.49 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.

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

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

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

Final £/kW Tariff

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

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

Where

FT = Final TNUoS Tariff expressed in £/kW

2.51 If the Final demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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

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

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

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

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

where:

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

RFT_{Di} = Revised Final Tariff (£/kW)

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

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

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

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

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

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

2.57 The factors which will affect the level of TNUoS charges from year to year include the forecast level of peak demand on the system, the Price Control formula (including the effect of any under/over recovery from the previous year), the expansion constant, the locational security factor, changes in the transmission network and changes in the pattern of generation capacity and demand.

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

Stability & Predictability of TNUoS tariffs

2.59 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in Appendix TN-8.

Chapter 5: Generation charges

Parties Liable for Generation Charges

5.1 The following CUSC parties shall be liable for generation charges:

i) Parties of Generators that have a Bilateral Connection Agreement with National Grid.

ii) Parties of Licensable Generation that have a Bilateral Embedded Generation Agreement with National Grid.

iii) Interconnector Asset Owners that have a Bilateral Connection Agreement with National Grid and/or Interconnector asset Owners of Interconnectors capable of exporting 100MW or more to the Total System.

5.2 **Appendix TN-5: Classification of parties for charging purposes** provides an illustration of how a party is classified in the context of Use of System charging and refers to the relevant paragraphs most pertinent to each party.

Basis of Generation Charges

5.3 The value of generation to be multiplied by the relevant generation tariff, for the calculation of generation charges, is set out below. For the avoidance of doubt, the intention of the charging rules is to charge the same physical entity only once.

5.4 The basis of the generation charge for Power Stations and Interconnectors (including Interconnector errors with the exception of Emergency Assistance actions) is the Chargeable Capacity and the short-term chargeable capacity (as defined below for positive and negative charging zones).

Positive Charging Zones

5.5 The Chargeable Capacity for Power Stations situated in positive charging zones 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 in positive charging zones 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 connected to a positive charging zone 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 connected to a positive charging zone 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 in positive zones referred to in Paragraphs 5.6 and 5.8 will be the capacity purchased either on a profiled firm[17] or indicative[18] 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.

Negative Charging Zones

5.10 The Chargeable Capacity for Power Stations and Interconnectors situated in negative charging zones 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.

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

[18] 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.

Example

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 situated in negative charging zones 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 situated in negative charging zones 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, the short-term chargeable capacity for LDTEC in negative zones 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, the LDTEC tariff in negative generation charging zones 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 zonal £/kW tariff. This annual TNUoS generation charge is split evenly over the 12 months and charged on a monthly basis over the year. For positive charging zones, 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 charging zones, 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.

5.18 The provisions described above for increases in TEC during the charging year shall not apply where the LDTEC (in any of its forms) has been approved for use before the TEC is available, which will typically mean the LDTEC has been approved after the TEC increase has been approved. In such instances, the party shall commence payments for TEC during the LDTEC Period for LDTEC purchased up to the future level of TEC and LDTEC Charges will only apply to LDTEC that is incremental to the TEC increase. For the avoidance of doubt, where TEC has been approved after LDTEC in a given year, these provisions shall not apply and the LDTEC shall be considered additional to the TEC and charged accordingly.

Ad hoc Charges

5.19 For each STTEC period successfully applied for, a charge will be calculated by multiplying the STTEC by the tariff calculated in accordance with Paragraph 3.3. National Grid will invoice Users for the STTEC charge once the application for STTEC is approved.

5.20 For Power Stations and Interconnectors utilising LDTEC (in any of its forms) the LDTEC Charge for each LDTEC Period is the sum of the charging liabilities associated with each incremental level of short term chargeable capacity provided by LDTEC within the LDTEC Period (assessed on a weekly basis). The charging liability for a given incremental level of short term chargeable capacity is the sum of:

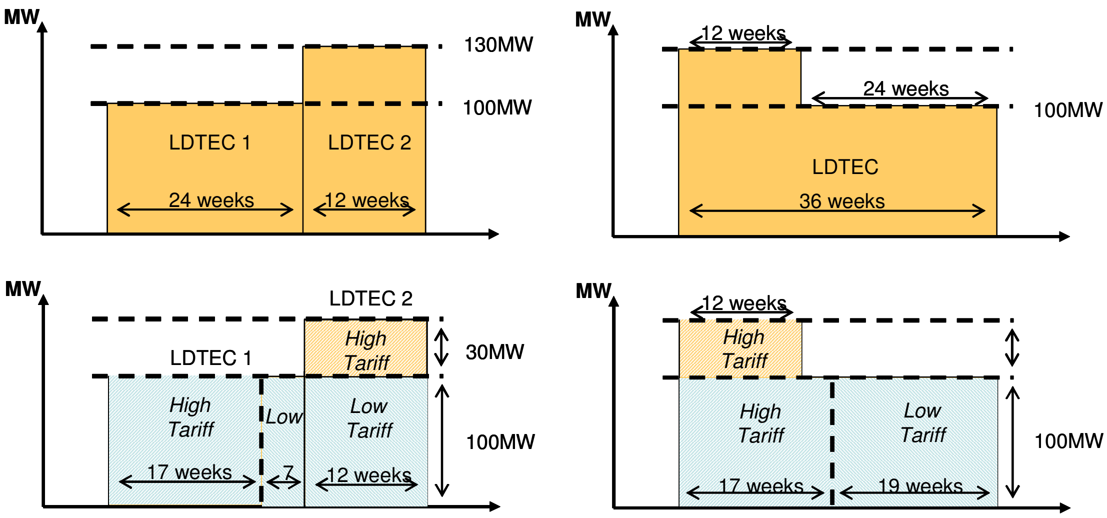
i) the product of the higher tariff rate (calculated in accordance with Paragraph 3.6) and capacity purchased at this increment for the first 17 weeks in a Financial Year (whether consecutive or not); and

ii) the product of the lower tariff rate (calculated in accordance with Paragraph 3.6) and capacity purchased at this increment in any additional weeks within the same Financial Year (whether consecutive or not).

5.21 For each LDTEC Period successfully applied for, the LDTEC Charge will be split evenly over the relevant LDTEC Period and charged on a monthly basis. LDTEC charges will apply to both LDTEC (in any of its forms) and Temporary Received TEC held by a User. For the avoidance of doubt, the charging methodology will not differentiate between access rights provided to a generator by LDTEC or through Temporary Received TEC obtained through a Temporary TEC Exchange (as defined in the CUSC).

Example

The diagrams below show two cases where LDTEC has been purchased: in Case A, two LDTEC Periods have been purchased; and in Case B one LDTEC Period has been purchased. The total capacity purchased in both cases is the same. The top diagrams illustrate the capacity purchased, while lower diagrams illustrate the incremental levels of short term chargeable capacities of LDTEC and the tariff rate that would apply to that capacity.



Case A

Case B

In both cases, the total amount charged for the LDTEC would be the same:

<u>Capacity charges at the higher tariff rate:</u>
- 17 weeks at the 100MW increment
- 12 weeks at the 30MW increment

<u>Capacity charges at the lower tariff rate:</u>
- 19 weeks at the 100MW increment

<u>Embedded Transmission Charges</u>

<u>5.22 The Embedded Transmission Charge is a Use of System charge levied on offshore generators whose offshore connection is embedded in an onshore distribution network.</u>

<u>5.23 The purpose of the Embedded Transmission Charge is to pass DNO charges that are levied on the GBSO to the offshore generator(s). This charge will</u>

include, but is not limited to, upfront charges, capital contributions as well as the ongoing Distribution Generation Use of System charges.

5.24 Where a DNO's charge relates to more than one offshore generator, the related Embedded Transmission Charge will be pro-rated based on the TEC of the relevant offshore generators connected to that offshore network.

5.26 Embedded Transmission Charges shall be levied as soon as reasonably practicable after these have been levied on the GBSO by the DNO.

Reconciliation of Generation Charges

5.27 The reconciliation process is set out in the CUSC and in line with 5.14 above.

5.28 In the event of a manifest error in the calculation of TNUoS charges which results in a material discrepancy in a User's TNUoS charge as defined in Sections 4.24 to 4.26, the generation charges of Users qualifying under Section 4.25 will be reconciled in line with 5.17 and 5.22 using the recalculated tariffs.

Further Information

5.29 **The Statement of Use of System Charges** contains the £/kW generation zonal tariffs for the current Financial Year.

Appendix 2: Worked Example

This appendix shows the derivation of the TNUoS tariff for a hypothetical offshore generator, and the effect on tariffs incurred by other Users. Please note that all costs and charges are indicative, and are for illustrative purposes only. The same example was used in the original consultation document, therefore illustrating the alternative treatment and targeting of a proportion of the non locational costs.

The tables below show the 2008/09 TNUoS tariffs for generation and half-hourly demand.

2008/09 Generation TNUoS Tariffs

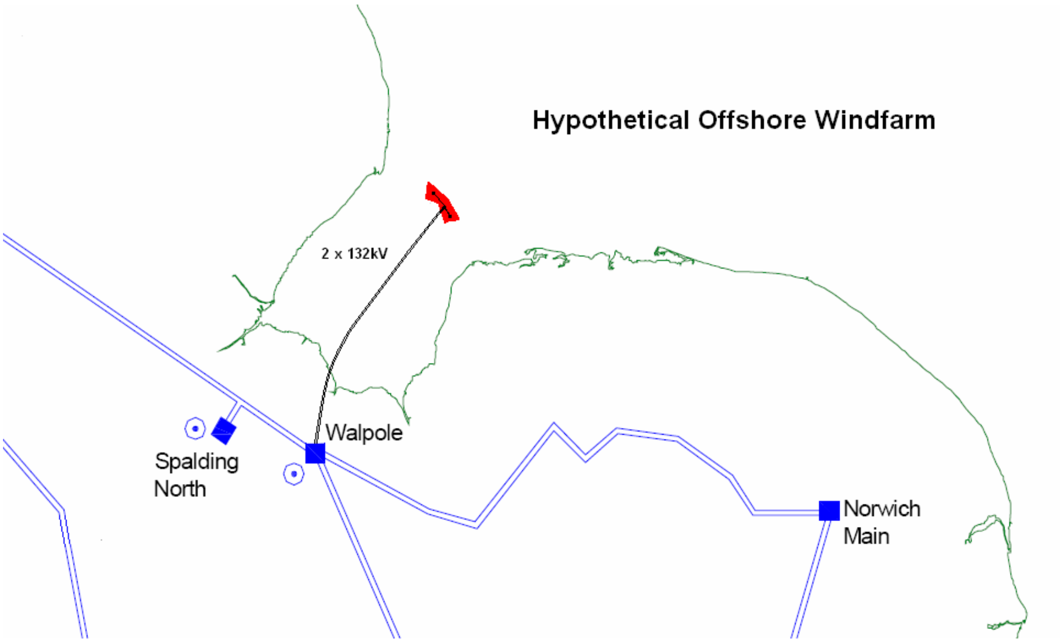
Zone No.	Zone Name	Generation Residual (£/kW)	Zonal Locational Element (£/kW)	Final Tariff (£/kW)
1	North Scotland	4.08	18.15	22.26
2	Peterhead	4.08	15.65	19.76
3	Western Highland & Skye	4.08	16.42	20.53
4	Central Highlands	4.08	12.63	16.74
5	Argyll	4.08	10.95	15.06
6	Stirlingshire	4.08	10.25	14.36
7	South Scotland	4.08	9.41	13.52
8	Auchencrosh	4.08	6.27	10.38
9	Humber & Lancashire	4.08	2.21	6.32
10	North East England	4.08	5.84	9.95
11	Anglesey	4.08	2.72	6.83
12	Dinorwig	4.08	5.71	9.82
13	South Yorks & North Wales	4.08	0.31	4.42
14	Midlands	4.08	-1.79	2.32
15	South Wales & Gloucester	4.08	-6.58	-2.47
16	Central London	4.08	-9.77	-5.66
17	South East	4.08	-2.89	1.22
18	Oxon & South Coast	4.08	-4.12	-0.01
19	Wessex	4.08	-6.68	-2.57
20	Peninsula	4.08	-12.63	-8.53

2008/09 Half-hourly demand TNUoS Tariffs

Zone No.	Zone Name	Demand Residual (£/kW)	Locational Element (£/kW)	Final Tariff (£/kW)
1	Northern Scotland	15.40	-12.59	2.81
2	Southern Scotland	15.40	-7.51	7.89
3	Northern	15.40	-4.57	10.84
4	North West	15.40	-0.55	14.85
5	Yorkshire	15.40	-0.64	14.77
6	N Wales & Mersey	15.40	0.00	15.40
7	East Midlands	15.40	2.16	17.56
8	Midlands	15.40	3.68	19.09
9	Eastern	15.40	2.90	18.30
10	South Wales	15.40	7.77	23.17

11	South East	15.40	6.04	21.44
12	London	15.40	8.08	23.49
13	Southern	15.40	6.73	22.13
14	South Western	15.40	9.75	25.15

This example uses a hypothetical 300MW generator, located in the Wash, 40km from the point of onshore connection at Walpole substation. The offshore connection would use two 500mm^2 132kV cables, each rated at 169MVA.[19] At £420k per km per cable, the total cost of the offshore cable would be £33.6m.



The connection would further use two 33/132kV transformers with 3 windings rated at 90/90/180MVA, at a cost of £9m (at £25/kVA). The associated switchgear costs £1.3m and are rated at 475MVA. The platform on which the offshore substation was located would cost £12.2m (£5m plus £20/kVA). This would give a total cost of the offshore substation of £22.5m.

It would also be necessary for the OFTO to install reactive compensation. Based on designs of potential schemes of which National Grid is aware, it is assumed that the requirements would be for 190MVar onshore (at a cost of £15/kVar) and 15MVar offshore (at a cost of £25/kVar), giving a total cost of £3.2m.

The total cost to the OFTO is therefore £59.3m. Annuitising this cost (assuming a 20 year asset life, a 6.25% cost of capital, and including an allowance of 1.8% per annum for maintenance and overheads, consistent with costs onshore) would give an annual revenue requirement of £6.3m. This would be apportioned as follows between the assets.

[19] All ratings and costs in this example are taken from figures supplied by ABB and BEAMA, and presented in "A security standard for offshore transmission networks – an initial joint Ofgem/DTI consultation", December 2006, available at http://www.ofgem.gov.uk/Networks/Trans/Offshore/ConsultationDecisionsResponses/Documents1/16413-211_06.pdf

Asset	Asset Cost (£m)	Annual Revenue (£m)
Cable + Reactive	36.8	3.91
Transformer	9.0	0.96
Switchgear	1.3	0.14
Platform	12.2	1.30
Total	**59.3**	**6.30**

Expansion Factor

The OFTO specific expansion factor would be derived by dividing the cable and reactive annual revenue (of £3.91m) by the capability of the cables (169MVA*2 = 338MVA) and the distance (40km) to give an equivalent expansion factor of £289/MWkm. This is further divided by the expansion constant (of £10.289/MWkm) to give an expansion factor of 28.1 for the offshore transmission circuits.

Security Factor

The circuit specific security factor is given by dividing the circuit capability (338MVA) by the relevant capacity of the generation (in this case 300MW based on its TEC). The resultant circuit specific security factor is therefore 1.13 (compared to the current onshore global security factor of 1.8).

Substation Tariff

The substation tariff would be calculated by considering the annual revenue and capability of each component of the tariff. In this example, an adjustment of £0.35/kW would be provided to reflect the typical cost of onshore civil works, to ensure only the incremental substation cost is considered. The table below shows the calculation of the substation tariff.

Asset	Annual Revenue (£m)	Capability / Rating (MVA)	Tariff (£/kW)
Transformer	0.96	360.0	2.66
Switchgear	0.14	457.0	0.30
Platform	1.30	457.0	2.84
Adjustment	-	-	(0.35)
Substation Tariff			**5.44**

The new circuit is then added into the DCLF transport model, and the additional annual revenue requirement of £6.3m is added into the tariff model. The annual charge the generator for its substation charge would be £1.6m. This amount would be removed from the revenue collected from the generation residual (to maintain the 27:73 per cent revenue split between generation and demand, respectively).

This produces the hypothetical generation and half-hourly demand TNUoS tariffs shown below, together with the change from existing TNUoS tariffs.

2008/09 Generation TNUoS Tariffs with hypothetical offshore generator

Zone No.	Zone Name	Generation Residual (£/kW)	Locational Element (£/kW)	Total Tariff (£/kW)	Difference (£/kW)
1	North Scotland	4.08	18.11	22.20	-0.06
2	Peterhead	4.08	15.61	19.69	-0.06
3	Western Highland & Skye	4.08	16.39	20.47	-0.06
4	Central Highlands	4.08	12.59	16.68	-0.06
5	Argyll	4.08	10.91	15.00	-0.06
6	Stirlingshire	4.08	10.21	14.29	-0.06
7	South Scotland	4.08	9.37	13.46	-0.06
8	Auchencrosh	4.08	6.23	10.32	-0.06
9	Humber & Lancashire	4.08	2.17	6.25	-0.06
10	North East England	4.08	5.80	9.89	-0.06
11	Anglesey	4.08	2.68	6.77	-0.06
12	Dinorwig	4.08	5.67	9.76	-0.06
13	South Yorks & North Wales	4.08	0.27	4.35	-0.06
14	Midlands	4.08	-1.83	2.25	-0.06
15	South Wales & Gloucester	4.08	-6.62	-2.54	-0.06
16	Central London	4.08	-9.80	-5.72	-0.06
17	South East	4.08	-2.93	1.16	-0.06
18	Oxon & South Coast	4.08	-4.16	-0.08	-0.06
19	Wessex	4.08	-6.72	-2.63	-0.06
20	Peninsula	4.08	-12.67	-8.59	-0.06
21	Offshore Generator	4.08	12.46	16.54	N/A

2008/09 Half-hourly demand TNUoS Tariffs with hypothetical offshore generator

Zone No.	Zone Name	Demand Residual (£/kW)	Locational Element (£/kW)	Total Tariff (£/kW)	Difference (£/kW)
1	Northern Scotland	15.45	-12.56	2.89	0.08
2	Southern Scotland	15.45	-7.48	7.97	0.08
3	Northern	15.45	-4.53	10.92	0.08
4	North West	15.45	-0.51	14.93	0.08
5	Yorkshire	15.45	-0.60	14.85	0.08
6	N Wales & Mersey	15.45	0.03	15.48	0.08
7	East Midlands	15.45	2.19	17.64	0.08
8	Midlands	15.45	3.72	19.17	0.08
9	Eastern	15.45	2.94	18.39	0.08
10	South Wales	15.45	7.80	23.25	0.08
11	South East	15.45	6.07	21.52	0.08
12	London	15.45	8.12	23.57	0.08
13	Southern	15.45	6.77	22.22	0.08
14	South Western	15.45	9.79	25.23	0.08

As can be seen, the annual charge for the total offshore generator would be £6.6m (comprised of £5.0m for circuit related costs, including the onshore network, and £1.6m for substation related costs).

Generator Local Charging (GBECM-11)

In November 2007, National Grid published GBECM-09[20], a charging consultation on the provision of a financial discount to reflect the reduced asset investment requirement for design variation connections such as single circuit or partial redundancy connections. The industry responses received revealed a wider issue with the fundamental charging arrangements for "local assets" associated with onshore generator spur connections. These fundamental charging arrangements prohibit a cost reflective local discount being provided without undermining the overall locational signal.

Consequently National Grid undertook[21] to develop an enduring solution for implementation on 1 April 2009, rather than proposing a partial modification for 1 April 2008. In October 2008, a Conclusion Report was published for the charging arrangements for infrastructure assets local to generation. For this illustration, it is assumed that charging arrangements within both GBECM-08 and GBECM-11[22] are applied.

The charging amendment proposed in the Conclusion 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 which is derived onshore from generic costs.

Within this example the substation local tariff for the offshore connection has been calculated from specific costs consistent with the methodology outlined in this Further Consultation and that used in the first base case example, above.

Under GBECM-11, the local circuit tariff is derived from applying a locally specific security factor and expansion factor to the marginal flow along the 'local' circuits to the first MITS node. In this example the local circuit is the offshore cable, the MITS node is Walpole and the cable's security and expansion factors are inherently calculated using specific local data.

The wider tariff is found by removing the local component from the total marginal cost at the offshore connection node. After the 'local' marginal cost has been removed, the offshore generator has the same 'wider' marginal cost as the first onshore MITS node. The offshore node therefore meets the zoning criteria for generation zone 13 which would have a tariff of £4.13/kW. The wider zonal tariffs remain calculated using a GB average Locational Security Factor and GB Expansion Factors as consistent with the current methodology.

[20] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/
[21] http://www.nationalgrid.com/NR/rdonlyres/FBC9DAE1-C4D7-4FCA-AE1F-59F4C3520B9A/22249/NationalGridDesignVariationDiscountletter.pdf
[22] See footnote 2

The effect of this on tariffs can be seen below.

Power Station	Generator Local Charging			
	Generation Local Tariff (£/kW)		Wider TNUoS (£/kW)	Total Tariff (£/kW)
	Substation	Circuit		
Offshore Generator	5.44	13.02	4.13	22.59

2008/09 TNUoS local and wider tariffs (£/kW), for a hypothetical offshore generator, showing effect of GB ECM-11

As can be seen, the annual charge for the total offshore generator would be £6.8m (comprised of £1.2m for onshore wider network circuit related costs, £3.9m for offshore local cable costs and £1.6m for offshore substation related costs).