National Grid

GB Transmission Charging: Use of System Charging Methodology Revised Proposals Consultation

Version 2

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Contents

1 Executive Summary

On 10 December 2004, the Authority published its decision document on National Grid's proposed GB electricity transmission charging methodologies that were contained in the GB Transmission Charging: Final Methodologies Conclusion Report to the Authority, published by National Grid on 30 September 2004.

The Authority concluded that although the Option A and B use of system methodologies submitted by National Grid had significant merits, it would not be consistent with its legal duties and obligations to approve either of the charging proposals. The Authority requested National Grid to develop revised use of system methodology proposals, and identified four specific areas where they invited National Grid to undertake further work:

- Negative demand tariffs, taking account of the Authority's decision that adjusting the Generation/Demand TNUoS revenue split under Option B to 10%/90% to avoid negative demand charges was disproportionate
- The simplified approach to calculating expansion constants
- The simplified approach to calculating lower voltage expansion factors
- The treatment of circuits with spare capacity

In terms of meeting the relevant licence objectives, the Authority concluded that both Option A and Option B meet the criteria of facilitating competition and taking into account developments in the transmission system. The Authority also concluded that Option B better meets the criteria for cost reflectivity than Option A. The Authority identified significant weaknesses in the cost reflectivity of Option A that did not appear to be offset by compensating benefits in terms of the facilitation of competition.

National Grid therefore believes that although further work is required, Option B should be used as the basis of the revised GB charging methodology, as it better meets the relevant licence objectives.

In response to the issues raised in the Authority's decision document, National Grid has reviewed the four areas in question and is proposing the following changes to the Option B methodology:

- 73% of the revenue to be recovered by Transmission Network Use of System tariffs should be recovered from demand, and 27% from generation
- Negative TNUoS demand tariffs should be constrained to a de-minimus £0/kW
- Transmission Owner Specific Expansion Factors should be employed to better reflect the likely development options for transmission voltages below 400kV
- The 275kV expansion factor should reflect the large amounts of the 275kV transmission system which is of 400kV construction.

National Grid is seeking views on the issues contained in this document with the deadline for responses being 5pm on 21 January 2005.

2 Introduction

On 10 December 2004, the Authority published its decision document[1] on National Grid's proposed GB electricity transmission charging methodologies that were contained in the GB Transmission Charging: Final Methodologies Conclusion Report to the Authority[2], published by National Grid on 30 September 2004.

The Final Methodologies submitted to the Authority contained a single connection charging methodology, and a preferred and alternative use of system charging methodology. A full description of the connection and the preferred and alternative use of system methodologies (otherwise known as Option B and A respectively), is contained in the Final Methodologies Conclusion Report.

This document contains National Grid's response to Authority's decision document, and describes the revised GB Use of System Methodology proposals developed in light of the guidance contained in the decision document.

2.1 Connection charging methodology

In accordance with its Transmission Licence, National Grid is required to determine both a connection and use of system charging methodology, approved by the Authority, as soon as practicable. In the Final Methodologies report submitted to the Authority at the end of September, National Grid proposed a shallow connection charging methodology, based on the connection arrangements currently in place in England and Wales. The Authority approved the proposed connection charging methodology subject to a condition that National Grid review and potentially revise, within the next two years, the calculation of site specific maintenance charges.

National Grid will address the requirement to review the site specific maintenance charging regime after 1 April 2005.

2.2 Balancing Services Use of System charging methodology

In the Final Methodologies report submitted to the Authority in September 2004, National Grid proposed a two part Use of System charging methodology: Balancing Services Use of System (BSUoS) and Transmission Network Use of System (TNUoS). The Authority concluded that had it been possible to separately approve National Grid's proposed BSUoS charging methodology, it would have been suitable for approval. National Grid, therefore, does not propose any significant changes to the BSUoS methodology. However as a consequence of the development of the contractual arrangements for large embedded licence exemptible generation in Scotland, we believe it may be appropriate to consider a modification to the definition of the chargeable party.

Currently the England and Wales methodology levies BSUoS on the Balancing Mechanism Unit lead party. In light of the proposals for large licence exemptible embedded power stations in Scotland, large embedded power stations may be able to opt for another party to be responsible for their output and participation in the Balancing Mechanism. In order for BSUoS to be levied on the BSC party in line with

[1] National Grid's proposed GB electricity transmission charging methodologies: The Authority's decisions, December 2004, 275/04
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9584_27504.pdf
[2] National Grid's GB Transmission Charging: Final Methodologies Consultation, August 2004
http://www.nationalgridinfo.co.uk/betta/pdfs/GB_Charging_Conclusion_Report.pdf

the existing England and Wales methodology, rather than the power station, it would be necessary for National Grid to have in place an appropriate bilateral agreement with the BSC party responsible for the output, in addition to the power station.

National Grid believes there may be merit in revising the BSUoS methodology so that in such cases, the BSUoS charge is levied on the power station. This would have the benefit of avoiding the requirement to establish new agreements with BSC parties, solely to facilitate the charging and billing of BSUoS.

National Grid therefore proposes to revise the BSUoS methodology, such that if large embedded licence exemptible power stations can opt for another party to take responsibility for their station's output and participation in the Balancing Mechanism, then the BSUoS liability would be on the power station and not the associated BSC party.

National Grid notes that in the NGC System Operator Incentive Scheme for April 2005: Initial Proposals, published by Ofgem on 17 December 2004[3], Ofgem seek views on the adoption of a "net losses incentive scheme" rather than the current "gross losses" arrangement. If such a change is adopted, we do not believe it would have any impact on BSUoS charges and we would therefore reflect such a change in the statement of the use of system methodology.

2.3 Transmission Network Use of System charging methodology

The Authority concluded that approving either of National Grid's proposed TNUoS charging methodologies would not be consistent with its legal duties and obligations. Whilst Option A and Option B had significant merits, in the Authority's view both had areas of weakness and therefore concluded that the interest of consumers would be better served if National Grid came forward with revised proposals in light of the views set out in the decision document, specifically:

Option A
The Authority identified significant weaknesses in the cost-reflectivity of Option A that did not appear, on the basis of the available evidence, to be offset by compensating benefits in terms of facilitating competition.

Option B
The Authority concluded that National Grid's proposal to increase the share of total revenue recovered from suppliers and large users under Option B to 90% (as compared to the current 73%) was a disproportionate measure relative to the problem that it was seeking to address, i.e. negative demand charges in the North of Scotland.

Additionally, the Authority identified a number of areas where National Grid's proposals had raised issues of concern and recommended that these proposals be reviewed and potentially refined and/or explained in more detail. These areas are as follows:

- The unit cost of incremental capacity
- The calculation of expansion factors under Option B

[3] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9613_28004.pdf

- Treatment of spare capacity

This document seeks to address the issues highlighted in the Authority's decision document and offers a revised GB use of system charging methodology that National Grid believe better meets the relevant licence objectives, and takes account of the Authority's concerns set out in their decision document.

3 The Authority's assessment of National Grid's proposals

The Authority concluded that the interest of consumers would be better served if National Grid came forward with revised use of system charging proposals taking into account the views expressed in the decision document. The Authority also identified a limited number of areas where National Grid's proposals raised issues of concern and considered that these should be reviewed when developing revised proposals.

In terms of assessing the proposals, the Authority has done so against the relevant licence objectives of National Grid. Additionally, the Authority has assessed the proposals against the legal duties and obligations of the Authority.

3.1 Assessment of National Grid's proposals against relevant licence objectives

3.1.1 Facilitating competition

The Authority concluded that National Grid's proposed Option B and the alternative methodology Option A both facilitate effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitate competition in the sale, distribution and purchase of electricity.

The Authority concluded that the adoption of a single methodology applied across GB, based on the consistent application of principles and presented in a transparent manner, would appear to be important in facilitating competition. In the Authority's view, both Option A and Option B possess these generic characteristics.

The Authority concluded that in respect of facilitating competition, both Option A and Option B are improvements on the prevailing charging arrangements that operate across England and Wales and Scotland, and in relation to the Scotland – England interconnector.

3.1.2 Cost-reflectivity

In respect of the cost-reflectivity of Option A and Option B, the Authority reached the following conclusions:

DCLF

The DC loadflow network model adopted in Option A and Option B, represented a reasonable characterisation of the network and was viewed to be an appropriate basis on which to develop cost-reflective charges.

Expansion factors

The Authority concluded that Option B is more cost reflective than Option A as the costs of providing additional transmission capacity is related to the voltage at which additional capacity is provided. Furthermore, it is generally more robust to assume that a significant proportion of incremental capacity will be provided at the prevailing voltage, as the investment plans of the transmission licensees in the context of Transmission Investment for Renewables ("TIRG") project[4] would suggest.

However, the Authority was not persuaded that a simplified approach was the most robust, cost-reflective approach to the calculation of expansion factors. The assumption adopted that, across GB, 20% of additional capacity will be provided at a voltage higher than the prevailing voltage could, potentially, be developed to be more reflective of future costs of providing additional capacity. The Authority therefore invited National Grid to review this issue, and if appropriate to refine the approach or to explain in more detail the basis for the approach.

Spare capacity

The Authority concluded that there is some merit in the arguments presented as to why Option A and Option B already reflect the presence of spare capacity on particular circuits. However, the Authority invited National Grid to review the issue, and if appropriate to refine the approach or explain in more detail the basis for the approach.

System security

The Authority concluded that a model that reflects the costs of providing security on a locational basis would appear more cost-reflective than a model that ignores the need to accommodate parties on a secure network.

Unit cost of incremental capacity

The Authority recognised that a unit cost that allows for a wider range of methods of providing additional transmission capacity could be a more accurate characterisation of actual costs. The Authority invited National Grid to consider, in developing revised proposals, whether the approach to the issue could be refined, and/or to explain in detail the basis for the chosen approach.

The Authority has also requested that National Grid present, in the context of consulting on revised proposals, further analysis on how the tariffs derived through its proposed methodology relate to actual forecast investment costs in the context of the TIRG project or planned transmission network investment more generally.

3.1.3 Reflecting developments in the transmission system

The Authority was satisfied that the element of the use of system methodology proposed by National Grid pertaining to TNUoS charges does, as far as reasonably practicable, properly take account of developments in the transmission licensees' transmission businesses.

[4] Transmission Investment for Renewable Generation – Initial proposals, August 2004, http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/8267_19604_tirg_ip.pdf

3.2 Consistency with legal duties and obligations

3.2.1 Compliance with European law

Proportion of revenue recovered from suppliers and large users

The Authority concluded that National Grid's proposal to increase the share of total revenue recovered from suppliers and large users under Option B to 90% (from the 73% share that applies today) was a disproportionate measure relative to the problem it was seeking to solve, i.e. negative demand charges in the North of Scotland. It is the Authority's view that the costs of this aspect of Option B are disproportionate to the benefits that might accrue from avoiding negative demand charges.

The Authority was not persuaded by the arguments that there is a problem to address with negative, but cost-reflective, demand side charging. The Authority considered that the aspect of Option B addressing the issue of negative demand charges would place an additional burden on consumers. Whilst in the medium to long term the net effect on consumers might be expected to be zero, as wholesale prices adjust to reflect lower costs to generators, in the short term this aspect of Option B might be expected to result in a net increase in costs to customers.

The Authority was not persuaded that proper consideration had been given as to whether other changes such as to the basis of charging could be practically implemented to accommodate negative demand charges or whether alternative approaches to the issue had been considered. The Authority believed that alternative approaches could be effective in addressing the issue, and that such alternatives would likely be less burdensome on consumers.

Burden on individual parties as a result of location

The Authority was not persuaded by the arguments that suggested that the locational tariffs derived under Option A or Option B would place a disproportionate effect on individual parties located at different points on the network. The Authority was also of the view that suggested modifications to National Grid's proposals to constrain tariffs, either directly or indirectly would unduly penalise some parties to the benefit of others, without objective justification.

3.2.2 Protecting the interests of GB electricity customers

The Authority was unable to approve Option B on the grounds that it is not proportionate. The Authority concluded that had Option B been considered to be proportionate, in all circumstances, it would have offended the requirement that the Authority best protect the interests of consumers.

The Authority also reached the conclusion that it would not be in the best interests of electricity consumers for the Authority to approve Option A. The Authority viewed Option A to have significant weaknesses in terms of cost-reflectivity that did not appear to be offset by benefits in terms of the promotion of competition.

4 National Grid's assessment of the Authority's decisions

In developing the GB charging methodologies, National Grid has an obligation to meet its relevant licence objectives of:

- Facilitating competition
- Ensuring that charges are cost reflective
- Taking into account developments in the transmission licensees' transmission businesses

In terms of meeting these relevant licence objectives, the Authority concluded that both Option A and Option B meet the criteria of facilitating competition and taking into account developments in the transmission system.

In terms of ensuring cost reflectivity, the Authority has concluded that Option B better meets the criteria than Option A. The Authority identified significant weaknesses in the cost reflectivity of Option A that did not appear to be offset by compensating benefits in terms of the facilitation of competition.

National Grid therefore believes that Option B should be used as the basis of the GB charging methodology, but acknowledge that further work and/or development is required in the following areas where issues have been raised in the Authority decision document:

- The Authority believes that moving to a 90%/10% Generation/Demand revenue split is not a proportionate approach to addressing the problem of negative demand charges
- The Authority did not believe the simplified approach adopted to calculating GB wide 275kV and 132kV expansion factors was the most robust or cost-reflective
- The Authority was concerned that the arguments presented as to why Option B already reflects the presence of spare capacity on particular circuits had not been made clearly or consistently to date
- Although the Authority did not believe that National Grid's utilisation of the average cost of building new 400kV lines in the calculation of expansion constants systematically overstated costs, they invited National Grid to consider whether and how its simplified approach could be refined and/or to explain in detail the basis for its chosen methodology. The Authority also asked National Grid to present further analysis on how the tariffs derived through its proposed methodology relate to actual forecast investment costs

5 Revised Proposals

5.1 Generation/Demand revenue split

Authority's decision
In section 5.22 of the decision document, the Authority concluded that the proposal under Option B to increase the share of total revenue recovered from suppliers and large users to 90% (from the current 73%) was a disproportionate measure relative to the problem it was seeking to resolve, i.e. negative demand charges in the North of Scotland.

The Authority was not persuaded by the arguments that there is a problem to address with negative, but cost reflective, demand side charging.

National Grid response
In light of this decision National Grid proposes to adopt a 27%/73% split of total revenue recovered from TNUoS tariffs between generation and demand (G/D split). This is the existing split of revenue between generation and demand in the England and Wales methodology and hence is what we have previously argued is the starting point for the GB charging methodology in the absence of any specific requirement to change.

5.2 Negative demand charges

The proposed move to a 27:73 G/D split in the GB charging methodology would however, create the possibility of negative demand tariffs in the North of Scotland.

The Authority was not convinced under the proposed Option B methodology that there was necessarily a problem to address with negative, but cost reflective, demand side charging. In the Authority's view, the issues highlighted by National Grid appeared to relate to the use of TRIAD charging i.e. charging on the demand at the three periods of system peak demand.

If negative demand tariffs exist then use of a TRIAD charging base would clearly focus the charge on a small number of half hours over the winter and create a greater incentive on demand to increase at times of expected system peak and also for embedded generation to suspend operation over these periods. We believe such an incentive is clearly undesirable from a system security perspective.

There are of course ways to address the security of supply concerns that would be presented by the existence of negative demand charges. One option would be to dilute the pricing signal by spreading the charging base over a wider period. In doing so however, this would make the charges less cost reflective as they would not be targeted on the cost drivers i.e. the system peak conditions. In terms of this aspect it would, therefore, require a judgement as to whether the loss of cost reflectivity could be justified given the need to address the security of supply concerns and hence that the methodology would reflect the costs incurred as far as reasonably practicable.

For example, non half hourly metered demand in England and Wales uses the wider charging base of the daily energy consumption between 4pm and 7pm throughout the year.

A similar approach could be applied to the negative demand tariff charging base. There would still be a perverse incentive on generation and demand at times of system peak, but this pricing signal would be significantly diluted and hence potentially ineffective when the overall economics of taking demand are taken into account. Alternatively, to provide an absolute guarantee that all system security concerns are addressed, the negative tariff could be converted into a 24 hour commodity payment.

There would clearly be implications for our charging and billing systems to bear in mind when considering a negative demand charge with a revised charging base. Systems would need to be developed to accommodate the new type of charge and its charging base. Whilst at this time we believe we could have the necessary system changes in place, this would introduce a significant additional risk into the BETTA programme of works at a relatively late stage in the project's life.

In addition to the system security concerns associated with negative demand charges, the impact on embedded generation associated with demand charging must also be considered. Under the Option A and B proposals licence exempt embedded generation would be treated as negative demand and therefore receive a payment of the relevant demand tariff either directly or indirectly (assuming a positive TNUoS demand tariff). This payment would be made directly where the appropriate bilateral agreement is in place, or to the supplier responsible for the generation where the generation is not explicitly participating in the Balancing Mechanism.

Under the Option B proposals embedded generation would have expected to receive a payment, either directly or indirectly, of over £2/kW. If negative demand charges were implemented, this would change to a charge on the embedded generation, rather than a payment to the generator. This could have an impact on the contracting arrangements both between National Grid and embedded generation in Scotland, and also between suppliers and the embedded generators. We do not think that it is desirable to add this additional uncertainty into the decision making processes associated with the establishment of the GB contractual arrangements, at this critical time.

A further complication to consider with negative demand tariffs would be the requirement to change the Connection and Use of System Code to deal with the forecasting and reconciliation of any negative charge. Once the methodology was developed, the consequential amendment to the CUSC would be need to be drafted, which would then be subject to the CUSC amendment process.

Whilst we agree with the Authority that the system security issues with negative demand charges are a function of the charging base, we believe the wider concerns including the impact on contractual arrangements, and the practical implementation risks, justify the development of alternative options to avoid negative demand charges.

Options to address negative demand charges

We note that the Authority did not believe that a change to the generation and demand split was a proportionate response to the problem of negative demand charges. Furthermore the Authority did not believe the approval of Option B, would protect the interest of GB electricity customers. In developing revised proposals to remove negative tariffs, we have therefore considered directly the proportionality of any proposals to the problem being addressed and the impact on end consumers.

Arbitrary “squeezing” of tariff differentials (such as scaling) to ensure they remain positive does not seem a proportionate response to the problem, as it would have a greater impact on users at the extremities of the GB system compared with those nearer the centre. Hence this could be seen as being unduly discriminatory across GB.

Another option to remove negative demand tariffs would be to merge the Scottish Hydro demand zone with the Scottish Power demand zone. This would result in a small reduction in the Scottish Power demand tariff, but would clearly constitute a cross subsidy between suppliers in the two zones and hence also be seen as unduly discriminatory across GB.

Our preferred option for dealing with negative demand charges would be to establish a minimum £0/kW demand tariff principle for a zone. The lowest a demand tariff could go is £0/kW (and 0p/kWh for the Non Half Hourly metered demand), and the excess revenue would then be divided non-locationally to reduce the tariff in all other demand zones equally and maintaining the overall G/D split.

The question is then how proportionate this methodology is compared to the problem it is seeking to address. Using the tariffs in Appendix 1 as a guide, this mechanism would reduce demand tariffs uniformly across GB (excluding Scottish Hydro) by up to 2p/kW. Whilst this could also be perceived as a cross-subsidy given the removal of the cost reflective negative signal, by spreading the effect non-locationally across all demand, the cost reflective differentials are maintained across GB, and the impact on the wider community of the measure is negligible. We believe that this is a proportionate response to the issue of negative demand tariffs, and would only have a very minor impact on end consumers.

Longer Term solutions

We note that the Authority considered that in the medium to longer term the change to the G/D split under Option B would have a zero net effect on consumers, as wholesale prices would adjust to reflect the lower cost to generators. This raises the question as to whether any measure to deal with negative demand charges should be temporary, and that the option to change the G/D split could be seen as a viable longer term option. For example, it could be phased in over a number of years, to allow the fully cost reflective tariff differentials to operate unconstrained. For example, 5% steps could be adopted each year (7% in the first year), arriving at the 10/90 split in 2008/9.

Alternatively, the other longer term option might be to assess whether any changes to the charging base for potential negative demand zones would be an appropriate longer term solution if some of the challenges we have set out above could be addressed.

Such longer-term proposals would not effect the initial GB use of system charging methodology, and hence we would suggest they are considered separately post BETTA Go-Live.

5.3 Unit cost of incremental capacity

Authority's decision

In section 5.22 of the decision document, the Authority describes their views on the unit cost of incremental capacity. The Authority recognised that a unit cost which allowed for a wider range of methods of providing additional transmission capacity could be a more accurate characterisation of actual costs. However, the Authority was not persuaded by the arguments that NGC's simplifying assumption, to adopt the average cost of building new 400kV lines, systematically overstates the costs. The Authority considered that this view was supported by information submitted by the three transmission licensees on the cost of providing incremental capacity in the context of the TIRG report.

The Authority has, however, decided to invite NGC to consider, in developing its revised proposals, whether and how its approach to this issue could be refined in the light of respondent's views, and/or to explain in detail the basis for its chosen approach.

National Grid response

There has been a great deal of attention given to the derivation of the unit cost of incremental capacity i.e. the expansion constants, throughout the development of the GB charging arrangements. We note the Authority's statement that our proposed approach did not systematically overstate the costs. The Authority's statements suggest that our Option B expansion constants are generally appropriate and that unless substantial new supporting evidence becomes available, there is only limited scope to propose changes in this area, and in particular changes which significantly reduce costs, without making the charges less cost reflective.

One respondent to the GB charging consultations provided detailed analysis illustrating their belief that the expansion constant values should be significantly lower than those proposed by National Grid. This detailed assessment looked at the various different techniques available to a Transmission Owner to provide incremental capacity, in addition to the construction of new circuits.

In earlier reports we have set out our response to the proposals on expansion costs submitted by respondents to previous consultations (which largely focused on the derivation of the 400kV expansion constant), and our views have not changed from those previously stated with regard to these proposals. Furthermore, we believe the Authority's view that our approach did not systematically overstate costs, supports our previous conclusions. We have, however, considered the view expressed in the Authority's decision document to review our conclusions in this area and in particular to provide analysis of the differentials against the published investment costs from the Transmission Investment Review Group (TIRG). We have, therefore, undertaken further analysis to review our conclusions on expansion constants. Whilst some of this analysis relies on data which is commercially sensitive, we have summarised the findings in the following section which also sets out our conclusions with regard to the methodology underpinning the calculation of expansion constants.

5.3.1 Review of Expansion Constant Calculation

We accept that, in reality, a significant proportion of incremental capacity built on the transmission system will not be new build. However, we do believe that new build costs are a reasonable estimate of the average cost of providing incremental capacity.

Incremental transmission capacity can be provided in a number of ways in addition to new build:

- Conductor re-profiling
- Re-conductoring
- Voltage uprating

Re-profiling
Where conditions allow, conductor re-profiling (also known as hot-wiring) can be undertaken to deliver modest additional capacity, by allowing the conductors to operate at a higher temperature. If the assets are capable of operating at the higher temperature, it may only be necessary to tighten the conductors so that the increased sag is acceptable in terms of the safe operation of the circuit.

The amounts of additional capacity vary depending on the characteristics of the circuit. Increasing the operating temperature of 2x400mm^2 ACSR conductors from 65^{o}C to 75^{o}C would increase the post fault continuous winter rating by 120MW. For a 4x400mm2 ACSR conductor, increasing the operating temperature from 65^{o}C to 75^{o}C would increase the winter rating by 240MW. The ability to hot-wire is, however, limited. An assessment of recent National Grid schemes shows that where we identify a benefit in hot-wiring, the detailed surveys of the circuits indicates that due to the type and condition of the assets, and the nature of the route, only 50% of the circuits can be operated at a higher temperature.

Where the condition assessment determines that a circuit can be hot-wired with minimal work, the cost of the uprating can be very low, in the order of 20% of the cost of new build. Where significant works are required such as changing the conductor joints or tower steelwork strengthening, the cost would be significantly higher.

Re-conductoring
Another technique to increase the capacity of any circuit is to replace the conductors. The availability of this option will depend on a number of factors but primarily the tower types.

In previous consultations we have stated our view that this technique does not necessarily provide incremental capacity on a cheaper basis (in terms of £/MWkms) than new build. This view is based both on actual costs of re-conductoring, and our generic cost estimating document which uses our latest costing information, and which the process for producing is externally audited.

From our assessment of re-conductoring projects, only 2 schemes produced £/MWkm values below that of 400kV new build. The average costs were approximately 130% of the cost of new build. On some circuits where incremental capacity is required, the only feasible and economic solution may be to use newer conductor types such as 2x620mm^2 GZTACSR. These conductor types are more expensive to install and normally involve tower steelwork strengthening, which can produce costs of over 250% that of new build.

In addition to our assessment of actual re-conductoring projects, we have also used our generic cost estimating document to derive re-conductoring costs. This study showed that uprating from 2x400mm^2 ACSR conductor to either 2x620mm^2 or 2x700mm^2 produces costs slightly lower than the average cost of new build. However, where the incremental capacity provided by the new conductor is smaller, the £/MWkm cost will be greater than the average cost of new build. For the four re-conductoring scenarios assessed, the average cost was over 140% of the cost of new build. In these scenarios it is assumed that there is no requirement for additional tower steelwork.

Voltage up-rating

Additional transmission capacity can be provided by changing the operating voltage of a circuit. It may be possible to modify a circuit operating at 275kV, to operate at 400kV by ensuring the circuit is adequately insulated, clearances are acceptable, and the necessary transformers are installed at one end.

In some cases a 275kV circuit may have been constructed at a higher voltage, but operated at the lower voltage. In such cases the main cost of the uprating would be for the voltage transformation and any reconfiguration work at each end.

For uprating from 275kV to 400kV, the transformation costs would include the purchase of at least two 400/275kV transformer of adequate combined ratings. We estimate the cost of installation of two transformers to be a minimum of £3m.

If no other work is required, the incremental £/MWkm would depend on the additional MWs and the length of the circuit. Using an average overhead line length in GB of 30km, and assuming the increase in circuit rating is at the top end of the range at 900MW (based on 4x400mm^2 conductor), then the incremental cost is on a par with the average cost of new build. The costs would be higher for shorter circuits and/or lower incremental capacity release, and vice versa.

It could be questioned, however, that the cost of transformers should not be included in the incremental expansion cost as currently such costs are charged for non-locationally, as substation costs within the England and Wales methodology. In the development of a new methodology which incorporates the cost of voltage up-rating, we must consider whether the proposal is as cost reflective as possible, and not simply exclude a cost because of how it is handled in another methodology. Our view is that, if voltage up-rating costs are to be included, it would be more cost reflective to include the transformer costs.

400kV Expansion Constant

In order to convert the above information into an expansion constant for 400kV overhead line, it is necessary to assign weightings to each of the reinforcement options.

Clearly the option of uprating the operating voltage is not applicable to the calculation of the 400kV expansion constant, which leaves re-conductoring, re-profiling and new build to consider.

New build is the most flexible option as the new circuit can be designed to deliver the necessary additional capacity. Although in many cases new build is the only option, particularly where large increments of additional capacity are required, new build would tend to be a last resort due to the environmental and consent sensitivities. Re-profiling is less contentious but is only practical where relatively low levels of incremental capacity is required, and is therefore rarely included in investment plans. Hot-wiring is also only an option where the circuit is already operating at a lower temperature, and where circuit conditions allow.

Re-conductoring is also less contentious from an environmental and consent perspective than new build, and is reasonably flexible, although the type of transmission towers will limit the maximum size of conductor that can be deployed.

Where medium to large amounts of incremental capacity are required, we believe that re-conductoring and new build would be the most common techniques used. From a forward looking planning perspective, re-profiling is a less likely option to be utilised. This can be seen in the investment plans for the transmission licensees, where in Scotland, there are no firm plans to hot-wire circuits, with the planned reinforcements involving new build and re-conductoring. It should also be noted that a large proportion of the GB transmission system has already been re-profiled or assessed for the capability for hot-wiring.

Set out below in Table 1 are three weighting scenarios, which we believe are reasonable and consistent with current transmission investment plans.

Table 1

		Weighting Scenario		
	Cost as % of New Build	**1**	**2**	**3**
Re-conductoring	140%	50%	40%	30%
Re-profiling	20%	20%	20%	20%
New Build	100%	30%	40%	50%
Average %		**104%**	**100%**	**96%**

It can be seen from this analysis that in general, the cost of new build is a reasonable estimate of the cost of providing incremental capacity.

275kV and 132kV Expansion Constants
These are discussed in the following section on Expansion Factors (Section 5.4).

5.3.2 Further analysis against the TIRG forecasts

The Authority requested that National Grid present, in the context of consulting on revised proposals, further analysis on how the tariffs derived through its proposed methodology relate to actual forecast investment costs in the context of the TIRG project or planned transmission network investment more generally. Table 2 on page 17 presents the results from this analysis.

The additional network capability established by proposed reinforcements has been quantified for network boundaries representing transmission pinch points identified in the GB Seven Year Statement[5] (see columns 1 through 4 on Table 2).

The indicative reinforcement costs (column 5) have been expressed as a cost per unit of capacity (in column 9). However, certain reinforcement costs relate to the establishment of switching facilities and the transfer of existing loads/generators to new substations, for example, as a consequence of uprating the voltage of existing lines or other network rearrangements. In order to make a meaningful comparison with parts of the TNUoS tariff, which provides locational signals reflective of the incremental costs required to transmit power over a distance and recovers other costs on a non-locational basis, the indicative reinforcement costs corresponding to substation works and those costs that arise from providing the capacity to transmit power over a distance have been identified (columns 5 & 6, respectively). Distance related capital costs have been expressed as a cost per unit of capacity (in column 10). These have been expressed in terms of an annual charge (in column 11) by applying the same annuity factors that are used to calculate the TNUoS tariff expansion coefficients.

In order to compare reinforcement unit costs with the TNUoS tariff it is necessary to either:

i) Express reinforcement unit costs as £/MW/km/yr so that they may be compared with TNUoS expansion coefficients. This would require an analysis of the component of the reinforcement providing security. Or

ii) Determine the tariff differential (including the locational security factor) corresponding to the distance over which the reinforcement enhances network capacity.

The second of these approaches has been taken in performing this analysis. Column 12 identifies the generation tariff for the zones that most closely correspond to the areas in which the reinforcement provides more entry capacity. Column 13 identifies generation tariffs for the zones beyond which the reinforcement provides no significant increase in capacity. The difference between these tariffs provides the locational signal that seeks to reflect the incremental network costs arising from reinforcements. It must be noted that this comparative approach is sensitive to the particular definition of tariff zones and their resolution.

Comparison of the reinforcement unit costs (column 11) and TNUoS locational signals (column 14) shows the following results:

a) Reinforcements on boundary B7, which install reactive compensation to improve the utilisation of existing network assets, has a unit cost somewhat less than the corresponding tariff differential.

b) The unit cost of the Sloy export reinforcement (boundary B3, where we have used our judgement of how costs divide between substation and distance related components) appears to match the TNUoS tariff locational signal to a reasonable degree.

[5] Interim Great Britain Seven Year Statement, NATIONAL GRID, November 2004 see http://www.nationalgridinfo.co.uk/betta/pdfs/interim_gb_sys.pdf

c) The reinforcement on boundary B5 appear to be predominately related to local issues but the component we have estimated to be distance related would appear to match, albeit a small tariff differential, reasonably well.

d) The unit costs of reinforcements requiring major new transmission lines (B4, Beauly-Denny) or a significant distance of reconductoring (B6 SP-National Grid interconnector) would appear to be significantly larger than the locational signal provided by the TNUoS tariff.

A number of potential reasons for the differences in the last case can be identified:

- It may not be possible to use all the potential capacity provided by a major transmission line upgrade until other constraints are resolved. For example, the interconnector upgrade provides just 600MW of capacity until voltage reinforcements and other stability issues are addressed. These may arise from future reinforcements (such as those of the type identified on boundaries B5 and B7).

- The particular cost of these reinforcements diverge from the average cost of 400kV overhead line used in the TNUoS expansion coefficients.

- The TNUoS tariff differentials and generation tariff zone definitions will clearly be sensitive to changes in the generation background. Hence if additional generation is located in the North of Scotland in excess of that which is assumed in the DC load flow model underpinning the locational differentials used in this analysis, then the tariffs may be higher. Hence it is possible that over time if additional generation is connected then the tariff differentials may increase to bring them more in line with the anticipated investment costs in the North of Scotland.

In conclusion, while the comparison of unit costs derived from specific reinforcements and those used in the TNUoS tariff may be subject to some deviation from the GB signals arising from the proposed charging methodology, we believe the analysis does demonstrate that the TNUoS tariff is not significantly overstating locational signals.

Table 2

Table: Comparison of Reinforcement Costs and TNUoS Tariff

GB SYS Boundary		Required reinforcement (as identified in phase 1 of Transmission Investment for Renewable Generation)	Existing Capability	Reinforced capability	Indicative cost £m	Bussing & substation connections Note a) £m	Distance related reinforcement component Note b) £m	Capital cost (total reinforcement) per KW capacity £/kW	Distance related capital costs per KW capacity £/kW	Annuitised distance related cost including O&M £/kW/yr	Generation tariff sending end Note c) £/kW/yr	Generation tariff receiving end Note d) £/kW/yr	Tariff differential £/kW/yr
B3	Sloy Export (SHETL)	275/132kV substation at Sloy & 132kV line Works	220	380	15	10	5	94	31	**2.6**	14.5	12.1	**2.4**
B4 (Also B1, B2)	SHETL - SPTL	Beauly – Denny 400 kV line (220Km)	1520	2700	300	60	240	254	203	**17.1**	22.1	12.9	**9.2**
B5	North – South (SPTL)	3 MSC's Series reactor @ Windyhill Switchgear replacement @ Easterhouse and Clyde Mill substation	2550	3300	35	25	10	47	13	**1.1**	12.9	12.1	**0.8**
B6	SPTL-NGC	Reconductor Eastern Interconnector, Upgrade Western Interconnector. New substations.	2200	2800	150	70	80	250	133	**11.2** Note e)	12.1	8.2	**3.9**
B7	North - Midlands	Predominately reactive compensation	10000	11000	40	0	40	40	40	**3.4**	4.9	1.1	**3.9**

Notes:

a) As the locational element of the TNUoS tariff signals just those costs that vary with distance, the costs that relate to network switching facilities have been separated.

b) These reinforcement costs refer to lines, reactive compensation and other costs which vary with distance.

c) This tariff value (taken from Option B of our final conclusions report September 2004) corresponds to the generation zone corresponding most closely to that benefiting from increased export capacity.

d) This tariff value corresponds to the generation zone beyond which no significant exporting capacity is provided.

e) Some thermal capacity provided by this reinforcement beyond the 2800MVA shown is not useable until other bottlenecks due to stability and voltage issues are resolved.

5.4 Expansion factors

Authority's decision

In section 5.16 of the Authority decision document, it is explained that the Authority was not persuaded, on the balance of evidence, that NGC's simplifying assumption that across GB, 20% of additional capacity is provided at a voltage higher than the prevailing voltage, was the most robust and cost reflective approach. The Authority invited NGC to review this issue, and if appropriate to refine its approach or to explain in more detail the basis for its original methodology.

National Grid response

Lower voltage expansion factors

Expansion factors applied to the voltages below 400kV are effectively expansion constants for the lower voltages, and the arguments follow on from those in the previous section on the unit cost of incremental capacity (Section 5.3).

Under Option B, the 275kV and 132kV expansion constants are based on 80% of the expansion cost at that voltage, and 20% of the expansion cost for 400kV. These values were based on information provided by the transmission licensees regarding their plans to develop their networks. In response to the invitation from the Authority to review this area, we have looked again at the calculation of these percentages, and the derivation of the lower voltage expansion constants.

In section 5.3 we have provided an assessment of the likely transmission investment options for increasing capacity for the 400kV, and provided additional support for our argument that the cost of new build is a reasonable estimate of the cost of providing incremental capacity. This is equally applicable to lower voltages.

Under Option B, an additional allowance was made for the likelihood of replacing circuits at a lower voltage, with circuits at 400kV. The percentages applied under Option B were derived from the circuit lengths planned for uprating by each licensee. These figures were added together and divided by the total GB length to produce the percentages applied under Option B.

The percentage of circuits is however much higher in Scotland than in England and Wales:

Table 3

	132kV	**275kV**
Scottish Hydro Transmission	33%	56%
Scottish Power Transmission	0%	7%
National Grid	0%	4%

The simplified approach under Option B has the effect of increasing the cost signal in Scotland and decreasing the pricing signal for 275kV in England and Wales. It could, therefore, be more cost reflective to apply licensee specific values by adopting Transmission Owner specific expansion factors for each of the transmission licensees areas, using the values in the table above.

Although this may be more cost reflective it could be seen as contrary to the other principles underpinning the GB methodology where modelling assumptions and factors are applied consistently across GB with no regional differentiation. We must also consider the compatibility of any such change with the overall model, which averages tariffs across generation and demand zones, and thereby defines the cost reflectivity of the final tariffs. Transmission Owner specific expansion factors could be seen as a move closer to circuit specific expansion constants, which we do not believe would be consistent with the other averaging in the current model. However, as the area of application of the Transmission Owner specific expansion factors would in most cases be wider than the size of the generation tariff zones, and equal to the size of the demand zones, we believe such a proposal would be consistent with the overall model.

Hence we would propose that this element of the methodology is changed to incorporate TO specific expansion factors. In essence this distinction only relates to 132kV and 275kV as the 400kV expansion constants would be the same as the issues described above are only relevant to voltages that have the potential for upgrade.

Other elements of the lower voltage expansion constants

In reviewing the calculation of the lower voltage expansion constants we have also considered the impact of voltage uprating, which is an option currently unavailable at 400kV.

For voltages below 275kV, voltage uprating is unlikely to be a credible option using the existing assets, and the higher operating voltage could only be achieved by new build. At 275kV, however, in many cases it would be possible to operate at the higher voltage using the existing circuit, once the necessary voltage transformation is installed and any other remedial works. As described in the previous section we believe the cost of voltage uprating from 275kV to 400kV, where the circuit is of 400kV construction, is comparable with the cost of 400kV new build on a £/MWkm basis.

Based on information provided by the transmission licensees, significant amounts of the 275kV network are constructed for operation at 400kV:

Table 4

Scottish Hydro Transmission	54%
Scottish Power Transmission	90%
National Grid	83%

On a GB basis this equates to 80% of the 275kV circuits.

It could be argued that when incremental transmission capacity is required on a 275kV circuit, if it is constructed for operation at 400kV, then the most likely reinforcement would be to undertake the necessary works to allow the circuit to run at the higher voltage. This would mean that the 275kV expansion constant should reflect the capability of voltage uprating from 275kV, which has a cost comparable with 400kV new build.

Hence incorporating this element into the expansion constant calculation for 275kV does seem to have merit and hence we are including this in the revised methodology proposal.

We have not been made aware by the Scottish transmission licensees of any 132kV circuits, which are built to operate at a higher voltage, and we therefore do not propose to refine the proposals for 132kV for this aspect. The proposed 132kV expansion factor would therefore solely reflect the planned new build uprating of 132kV circuits to 400kV.

We continue to believe the cable expansion factors should track the overhead line values. The new build cost is a reasonable estimate for transmission cable. It is also reasonable to assume that the percentages applied to overhead lines to reflect the plans for replacement at a higher voltage, are equally applicable to cabled circuits. We therefore believe it would be more robust and cost reflective that cable expansion factors should be on a Transmission Owner specific basis, including an allowance for planned uprating/replacement at a higher voltage.

Summary

In summary, in response to the Authority's request to review the methodology in this area, we propose the implementation of TO specific expansion factors for voltages below 400kV, based on the licensed areas for each of the transmission licensees. These would take account of both the planned uprating of circuits for the lower voltage to 400kV as notified to us by the transmission licensees and also the ability for the circuits at the lower voltage to be uprated without new build to 400kV.

The percentage of the lower voltage expansion factor which is proposed to be calculated on the basis of the 400kV expansion factor is as follows:

Table 5

	132kV	**275kV**
Scottish Hydro Transmission	33%	77%
Scottish Power Transmission	0%	90%
National Grid	0%	83%

The 132kV numbers are derived from the length of circuits planned for uprating to 400kV. The 275kV values are calculated from the length of circuits planned for uprating to 400kV, and also those 275kV circuits, which are of 400kV construction, although currently operated at 275kV. This is not the sum of the 275kV values in Table 3 and Table 4 in Section 5.4 (e.g. 56% and 54% for Scottish Hydro) as many circuits fall into both categories.

5.5 Spare capacity

Authority's decision
The Authority concluded that there is some merit in the arguments presented as to why Option A and Option B already reflect the presence of spare capacity on particular circuits. However, the Authority noted that this had not been presented clearly or consistently to date. The Authority therefore invited NGC to review the issue, and if appropriate to refine the approach or explain in more detail the basis for the approach.

National Grid response
We note the conclusion from the Authority that there is some merit in the arguments presented to exclude the modelling of spare capacity from the charging methodology. Below we have provided more detail on these arguments including worked examples.

Background
To fully explain our view that we do not wish to implement the existing England and Wales treatment of circuits with spare capacity in a GB methodology, it is necessary to summarise the principles and process behind the current Investment Cost Related Pricing (ICRP) methodology, as we believe that spare capacity is implicitly included.

TNUoS charges are based on the nodal marginal costs derived by a simple DC Load Flow study. This model contains a peak study as a large majority of investment is driven by the requirements for the system to meet the security standards during a worst case scenario, usually at the time of system peak.

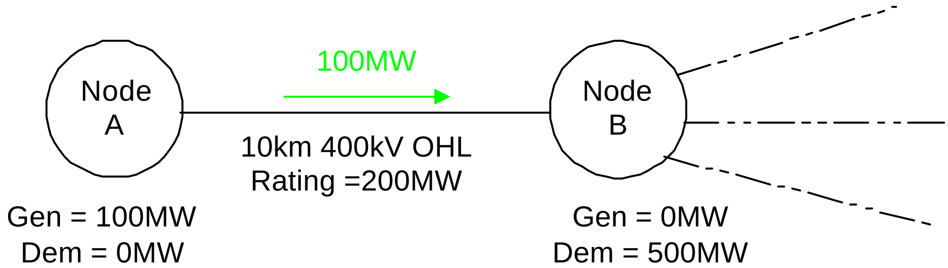
An example of how the nodal marginal costs are calculated can be found at the end of this section but in summary; a base case study is carried out to calculate the total cost in MWkm (from the sum of the circuit power flow * circuit length). The model is re-run to calculate the difference in electrical flows by considering an additional MW of generation capacity at each node in the network. Thus a nodal marginal cost in MWkm is calculated from the difference in total cost from the base study. This may be viewed as the relative effect on the transmission system from a generator on a particular node (the effect of demand on the same node is simply the negative value).

The cost that the user sees at a particular node is the relevant nodal marginal cost multiplied by the nodal power transfer (net sum of generation and demand). Thus the locational tariff costs passed to users are based on the physical attributes of the circuit (i.e. reactance and line length) plus the forecast usage of the transmission system. Finally a flat residual tariff is added which ensures that the tariffs recover the allowed revenue.

From the summary above (and confirmed by the worked example later) it has been shown that the locational costs recovered via user's tariffs are based on the reactance and length of circuits and on the forecast usage of the system. The model makes no reference to the physical capacity of the individual circuit. In fact there is no need to take into account the relative utilisation of a circuit as the Security and Quality of Supply Standards (SQSS) ensure that the network maintains a certain security level.

Looking at our ICRP methodology from the basic principle described above, we believe that removing the modelling of spare capacity would be more cost reflective.

Considering the simple spur network shown below, where node A has a generator connected via a 10km circuit to the main interconnected system. The generator has a maximum output of 100MW and due to the lumpy nature of investment the capacity of the circuit is rated at 200MW. The impedance of the circuit may be ignored in this simple example as the power flow has only one route for it to travel along.



Analysing the above network results in a nodal marginal cost differential between node A and node B based entirely on the length, i.e. the nodal marginal cost for node A is 10MWkm higher than node B. Using the expansion constant value of £9.78MWkm and ignoring the security element the differential nodal cost is £0.0978/kW.

The annuitised average cost for this circuit may be calculated as:

Expansion constant x circuit length x rating = 9.78 x 10 x 200 = £19,560

However, the cost recovered from the generator at node A is entirely based on the power flow on the circuit or in this simple case the capacity of the generator, hence:

Cost to customer = tariff x Power flow in kW = 0.0978 x 100 x 1000 = £9,780

Therefore, as half the capacity of the circuit is being used around half the cost is being recovered. If a scaling factor was added to reflect spare capacity, the costs recovered would fall below the amount the circuit is used, which would clearly be less cost reflective.

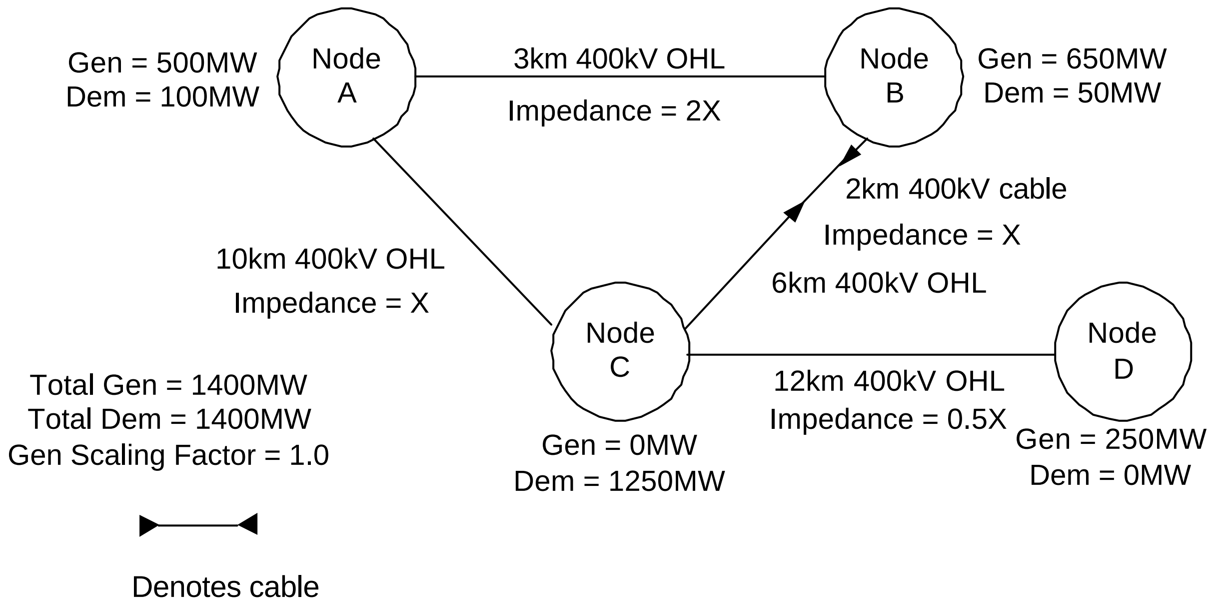
Although the example above is for a two node network, this is equally applicable to the wider system, where it is also the case that the locational costs recovered are proportional to the forecast usage of the transmission system.

The example above indicates that the effect of spare capacity is already recognised in the locational element of the tariff. Furthermore, as the locational costs are proportional to the usage of the system, the cost of providing the spare capacity on the system is therefore being recovered through the residual element of the tariffs. To model spare capacity by introducing scaling factors would be less cost reflective.

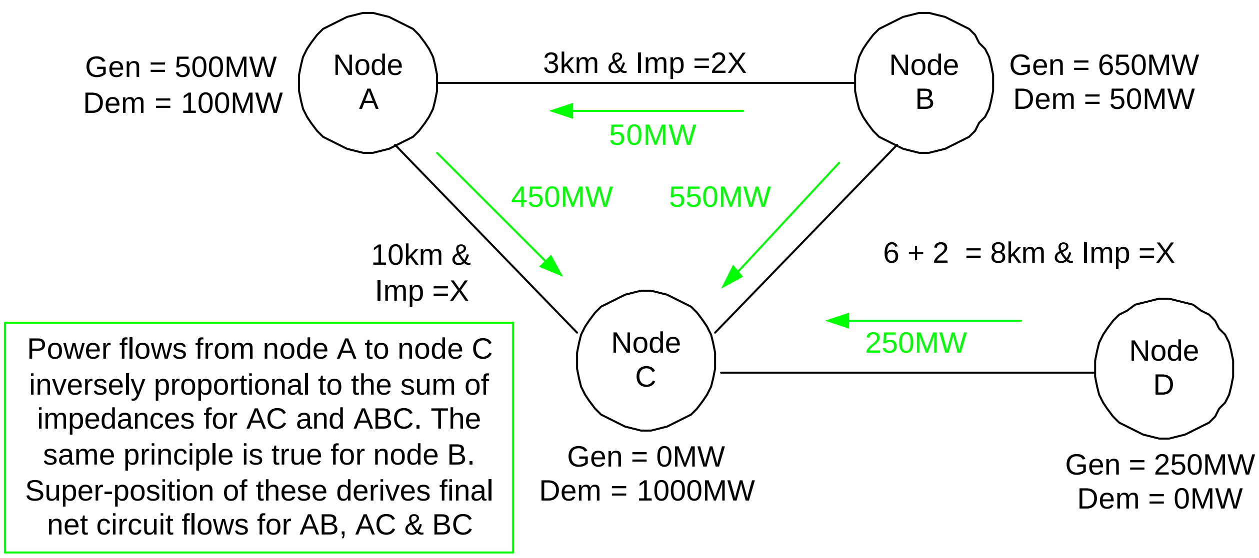
Example calculation to show effect of a Generators impact on costs

For the purposes of the DCLF Transport algorithm, it has been assumed that the value of circuit impedance is very much greater than the value of circuit reactance.

Consider the following 3 node network:



Base Case Calculation
Assuming Node A is the reference node, each circuit has an impedance based on X, and the 400kV cable circuit expansion factor is unity, the DCLF transport algorithm calculates the base case power flows as follows:



Nodes A, B and D export, whilst Node C imports. Hence the DCLF algorithm derives flows to deliver export power from Nodes A, Band D to meet import needs at Node C.

Step 1: Net export from Node A is 400MW; route AC has impedance X and route AB-BC has impedance 3X; hence 300MW would flow down AC and 100MW along AB-BC

Step 2: Net export from Node B is 600MW; route BC has impedance X and route BA-AC has impedance 3X; hence 450MW would flow down BC and 150MW along BA-AC

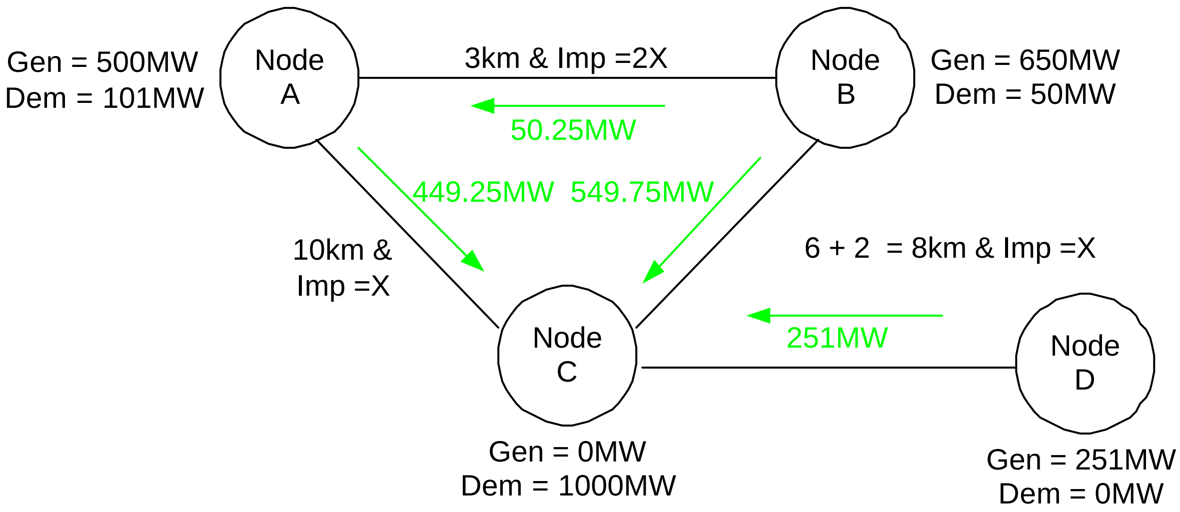
Step 3: Export from Node D is 250MW

Step 4: Using super-position to add the flows derived in Steps 1, 2 and 3 derives the following;

Flow AC	= 300MW + 150MW	=	450MW
Flow AB	= 100MW – 150MW	=	-50MW
Flow BC	= 100MW + 450MW	=	550MW
Flow CD	=		-250MW

Total cost = (450 x 10) + (50 x 3) + (550 x 8) + (250 x 12) = 12,050 MWkm (base case)

Nodal Sensitivity
We then 'inject' 1MW of generation at each node with a corresponding 1MW offtake (demand) at the reference node and recalculate the total MWkm cost. The difference in cost from the base case is the marginal km or shadow cost. This is demonstrated as follows:



To calculate the marginal km at node D:

Total Cost = (449.25x10)+(50.25x3)+(549.75x8)+(251x12) = 12,053.25 MWkm

Thus the overall cost has increased by 3.25 (i.e. the marginal km = 3.25).

Therefore a generator of 250MW capacity connected to node D would see a total cost of the nodal marginal cost multiplied by the power transferred from that node i.e. (3.25 x 250) 812.50 MWKm

Doubling the power transfer along circuit CD does not affect the nodal marginal cost

Total cost (base case) = (450x10)+(50x3)+(550x8)+(500x12) = 15,050 MWkm

Sensitivity on node D changes the total cost to:

Total Cost = (449.25x10)+(50.25x3)+(549.75x8)+(501x12) = 15,053.25 MWkm

Thus the nodal marginal cost remains at 3.25 MWkm

However, the cost seen by the user increases to (3.25x500) = 1,628.25MWkm

Therefore this establishes that the users costs are not based upon the relative utilisation of the circuit compared to its capacity but on actual use of the circuit.

Conclusion

The above examples indicate that introducing an additional element to reflect spare capacity would be less cost reflective. Therefore, our conclusions in this area have not changed and we continue to propose that no additional allowance for spare capacity should be included in the GB charging methodology.

6 Revised Use of System Methodology Proposals

6.1 Balancing Services Use of System Methodology

National Grid proposes to resubmit the methodology previously published under Option B, based on the current England and Wales methodology, with one adjustment for large licence exemptible embedded power stations.

Currently, the England and Wales methodology levies BSUoS on the Balancing Mechanism Unit lead party. In light of the proposals for large licence exemptible embedded power stations in Scotland, we propose to revise the BSUoS methodology, such that if large embedded licence exemptible power stations can opt for another party to take responsibility for their station's output and participation in the Balancing Mechanism, then the BSUoS liability would be on the power station and not the associated BSC party.

6.2 Transmission Network Use of System Methodology

National Grid proposes a revised Transmission Network Use of System Charging methodology, based on Option B submitted to the Authority in September 2004.

National Grid proposes the following changes to the Transmission Network Use of System methodology proposed under Option B:

- 73% of the revenue to be recovered by Transmission Network Use of System tariffs should be recovered from demand, and 27% from generation
- Negative TNUoS demand tariffs should be constrained to a de-minimus £0/kW, with a consequential non-locational reduction to all other demand tariffs to achieve revenue neutrality
- TO Specific Expansion Factors should be employed to better reflect the likely development options for transmission voltages below 400kV
- In addition to an adjustment to reflect the planned upratings from lower voltages to 400kV, the TO Specific Expansion Factors would include an allowance for lower voltage circuits constructed for operation at 400kV.

National Grid is not proposing any change to the methodology for the calculation of the 400kV expansion constant, or to include any explicit allowance for circuits with spare capacity.

Illustrative tariffs and generation tariff zones for the revised TNUoS methodology are shown in Appendix 1.

7 Next steps

National Grid welcomes comments on the issues raised in this consultation, in line with the timescales detailed below.

Following this consultation, National Grid intends to submit a revised proposal with updated indicative tariffs to the Authority on 28 January 2005. It is expected that the Authority will then carry out an Impact Assessment before considering approval at the end of February 2005. At this time we do not believe that there will be a requirement to give the Authority 150 days' notice of our intention to change TNUoS charges as we believe this is only applicable once the methodology has been approved.

The Authority have indicated in their decision document that they are minded to direct, following their approval of a GB use of system methodology, a reduced notice period for changes to user charges. The Connection and Use of System Code requires 2 months notice of a charge change unless otherwise directed by the Authority in accordance with the transmission licence.

Please note that the following timetable is indicative and therefore may be subject to change.

Date	**Details**
20 December 2004	National Grid publish revised proposals for industry consultation with indicative tariffs
End of December 2004	Indicative connection charges available
11 January 2004	Transmission Charging Methodologies Forum Brandon Hall – Coventry
21 January 2005	National Grid consultation closes
28 January 2005	National Grid submit revised proposal to the Authority with updated indicative tariffs
End January 2005	Final 2005/6 Connection Charge notice
04 February 2005	Ofgem publish impact assessment for consultation
18 February 2005	Ofgem consultation closes (two weeks)
End of February 2005	Authority decision announcement
End of February 2005	Publish final tariffs
01 April 2005	BETTA Go-Live – commence GB Charging

7.1 Views Invited

Comments are invited on the revised use of system methodology proposal set out in this consultation document. Although we would not wish to constrain the opportunity for respondents to express their views on any aspect on the Use of System Charging Methodology, we would be grateful if respondents could focus their submission on the specific changes to the methodology described in this document.

The closing date for responses to this consultation is 5pm on Friday 21 January 2005.

Please send responses to Richard Lavender, preferably by email, to richard.lavender@ngtuk.com or in writing to:

Richard Lavender
Senior Commercial Analyst
Commercial
National Grid Company plc
NGT House (Floor C3)
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

In the interests of transparency, National Grid intends to publish all responses to this consultation on its GB Charging website. **Therefore, please ensure that you clearly mark your response as confidential if you do not wish it to be made public.**

7.2 Indicative Connection and TNUoS Charges

As shown in the indicative timetable above, National Grid expects to publish the indicative connection charges for 2005/6 by the end of December 2004, and indicative TNUoS tariffs at the end of January 2005.

Final connection charges will be notified by the 31 January 2005. Final TNUoS tariffs are expected to be notified following the approval of a GB use of system charging methodology by the end of February 2005.

7.3 DCLF model

National Grid has available the DCLF ICRP transport model used to calculate the illustrative GB tariffs shown in Appendix 1. If you are interested in receiving the model please contact Louise Wilks at louise.wilks@ngtuk.com or in writing at the above address. Please note that if you have not previously done so, you will be required to sign a copy of the associated software licence agreement before being issued a copy of the model. The licence agreement restricts usage of the model to calculating GB TNUoS charges.

Please note that the DCLF model is not designed to deal explicitly with TO specific expansion factors, and until a new version of the model is released, regional expansion factors are modelled by adjusting circuit lengths.

Appendix 1: Illustrative GB TNUoS Tariffs and Zonal Mappings

This appendix contains illustrative GB TNUoS tariffs and zonal mappings based on the methodology described in Section 6 of this consultation document.

Please note that these tariffs are for illustration only and should not be used as indicative 2005/06 tariffs. Formal indicative tariffs will be published once the GB transmission charging methodologies have been approved and the revenue restrictions are known.

Revenue Assumptions

The tariffs provided in this Appendix are based on a total estimated TNUoS revenue recovery figure of £1070m, as provided by National Grid's latest view of the likely price control revenue. This is a reduction from the £1100m used in our earlier consultation, and reflects the refinements to our forecast in light of the published Ofgem price control consultations. However, there remains significant uncertainty in a number of areas within the price controls, and when the price control proposals are finalised we will update our forecast as appropriate.

The G/D split in the model is set at 27/73, in line with the methodology discussed in section 5.1.

The published demand tariffs have been adjusted in accordance with our preferred option for dealing with negative demand tariffs. Zone 1 demand tariffs are adjusted to a minimum of £0/kW with the tariffs in all other demand zones being reduced to maintain the 27/73 revenue split with generation, see section 5.2.

Inputs to the Transport Model

The latest tariffs calculated by the DCLF transport and tariff model must be considered in light of the following information:

All data used in the DCLF transport model is derived from the Seven Year Statements (SYS's) of National Grid, Scottish Power and Scottish Hydro. Previously the 2004 Scottish SYS's were not available, however, these documents have now been published along with the Interim GB Seven Year Statement[6] and the network data has been updated in light of any changes from the 2003 editions. All network datasets are derived from winter 2005/6 studies.

The England and Wales nodal data (the generation and demand at each node) has been derived from the winter 2005/6 SYS dataset. Due to non-standard Seven Year Statement layout, direct mapping of the Scottish Seven Year Statement data to the DCLF transport model is not possible and therefore additional analysis has been carried out to produce appropriate nodal values. For the Scottish demand data we are intending to use the user's forecast data as stated in the proposed methodology, however, at this time this has yet to be formatted for the DCLF model. Therefore, the Scottish demand data is similar to that released as part of the Final Methodologies consultation.

For Scottish generation nodes, including the modelling of negative demand, the model has been revised using the data contained in the interim SYS. The most significant change is the increase in generation in Scotland. The Interim SYS indicates an additional 1000MW of generation in Scotland in 2005/6 compared with 2004/5. This 1000MW was not contained in the transport model underpinning our

[6] Interim GB Seven Year Statement. Available at: http://www.nationalgridinfo.co.uk/betta/index.html

previous illustrative tariffs (Options A and B). This is because it was not included in the Scottish transmission companies' 2003 Seven Year Statements upon which the earlier illustrative tariffs were based.

For the purposes of calculating illustrative tariffs a GB locational security factor of 1.8 has been used. The final GB locational security factor for 2005/6 is currently being assessed according to the proposed GB methodology and will be confirmed with the revised proposals due in January 2005.

For the reasons discussed in Section 5.5 the under-utilisation factor which models circuits with spare capacity has been set to 100% in the model, effectively nullifying its effect.

An expansion constant for 400kV overhead lines of £9.80/MWkm has been used in the model to calculate the tariffs. This is the 2004/5 value for England and Wales of £9.51/MWkm inflated by an RPI figure of 3.1%. The RPI figure was calculated in accordance with the proposed GB methodology of the May to October average increase as defined in National Grid's Transmission Licence. Note that if the proposed GB methodology is approved this figure of £9.80/MWkm will apply for 2005/6 charge setting.

In line with the methodology described in Section 5.4 (expansion factors) the relevant Transmission Owner specific expansion factor has been applied to each circuit, and the values used in the model are shown below:

The Transmission Owner specific expansion factors are all based on the voltage specific expansion factors currently used in England and Wales in 2004/5:

400kV cable factor	20.67
275kV cable factor	20.88
132kV cable factor	27.85
400kV line factor	1.00
275kV line factor	1.74
132kV line factor	2.61

Transmission Owner Specific Expansion Factors

The model was run with the multi-voltage expansion factors shown above. However, the circuit lengths of the regional network data have been scaled prior to running the model to achieve the desired result. This scaling is necessary, as the model does not yet support the application of multi-region expansion factors.

In the National Grid region, the 275kV expansion factor has been changed to be based upon 17% of the 275kV factor and 83% of the 400kV factor with the 132kV factor remaining unchanged (see the summary in Section 5.4 for details). This resulted in the following expansion factors being applied:

National Grid Region

400kV cable factor	20.67
275kV cable factor	20.70
132kV cable factor	27.85
400kV line factor	1.00
275kV line factor	1.13
132kV line factor	2.61

In the Scottish Power region, the 275kV expansion factor has been changed to be based upon 10% of the 275kV factor and 90% of the 400kV factor with the 132kV factor remaining unchanged (see Section 5.4 for details). This resulted in the following expansion factors being applied:

Scottish Power Region

400kV cable factor	20.67
275kV cable factor	20.69
132kV cable factor	27.85
400kV line factor	1.00
275kV line factor	1.07
132kV line factor	2.61

In the Scottish Hydro region, the 275kV expansion factor has been changed to be based upon 23% of the 275kV factor and 77% of the 400kV factor. Additionally, the 132kV expansion factor has been changed to be based upon 67% of the 132kV factor and 33% of the 400kV factor (see Section 5.4 for details). This resulted in the following expansion factors being applied:

Scottish Hydro Region

400kV cable factor	20.67
275kV cable factor	20.71
132kV cable factor	25.48
400kV line factor	1.00
275kV line factor	1.17
132kV line factor	2.08

Zoning

The generation and demand zones have been calculated using the proposed GB zoning criteria and, as shown in the illustrative zonal map at the end of this document, the total number of generation zones is 23.

There have been some changes to the generation zones from those established under Option B due to revised proposals for Transmission Owner specific expansion factors and the new Scottish generation dataset. New transmission connected generation that is not locationally proximate to other generation nodes has resulted in additional generation zones e.g. Zone 2 “Strathbrora”. An example of the effect of the TO specific expansion factors on the 275kV network is the Cruachan node which is grouped with sections of the transmission system at the same voltage.

Small Generator Discount

Given the minded to statement by the Authority regarding the small generator designated sum, for illustrative purposes 25% of the sum of the residual generation and demand tariffs, is £3.63/kW as calculated using the revised proposals and assumptions set out above.

Using our initial estimate of eligible capacity the GB demand tariffs would increase by approximately £0.05/kW to make up the revenue shortfall. This adjustment to the demand tariffs is not included in the illustrative tariffs contained in this document.

Illustrative Generation Tariffs

Zone	Zone Name	GB Zonal Tariff (£/kW)
1	Peterhead	18.89
2	Strathbrora	23.86
3	Northern Highlands	22.10
4	Skye	24.89
5	Western Highlands	20.21
6	Central Highlands	16.49
7	Southern Highlands	14.49
8	Mid Scotland	12.92
9	South Scotland	12.11
10	Northern England	8.21
11	Lancashire, Pennines & Humber	4.94
12	Wylfa	5.65
13	Dinorwig	8.23
14	North Wales & Cheshire	2.42
15	South Yorkshire & Lincolnshire	3.28
16	Midlands & South East	1.08
17	North London	-0.30
18	Central London	-5.83
19	South Wales & Gloucester	-3.61
20	Oxon & South Coast	-1.16
21	Wessex	-5.11
22	Peninsula	-8.20
23	South West Wales	-2.52

Illustrative Demand Tariffs

Zone	Zone Name	GB HH Zonal Tariff (£/kW)
1	Northern Scotland	0.00
2	Southern Scotland	3.27
3	Northern	7.30
4	North West	11.05
5	Yorkshire	11.03
6	N Wales & Mersey	11.57
7	East Midlands	13.60
8	Midlands	15.10
9	Eastern	14.17
10	South Wales	18.52
11	South East	16.30
12	London	18.68
13	Southern	18.04
14	South Western	20.70

Illustrative Generation Zones