National Electricity Transmission System
Security and Quality of Supply Standard

Amendment Report GSR009

Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation

Prepared by the SQSS Review Group for submission to the Authority

Consultation Reference:	GSR009 and GSR009-1
Version:	1.0
Issued:	1st April 2011
Prepared By:	SQSS Review Group
Available Online At:	www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/

SP TRANSMISSION Scottish and Southern Energy nationalgrid

Executive Summary

In view of the significant changes anticipated in the future generation capacity and technology mix connecting to the National Electricity Transmission System (NETS), the NETS SQSS Review Group established a working group to review the criteria relating to the development of the Main Interconnected Transmission System with regard to intermittent sources of generation, and propose any modifications required to ensure they will lead to the appropriate development of the transmission system.

The working group consulted on the principles of its proposals in June 2010, and on the NETS SQSS text required to implement the proposals in October 2010.

The proposals include the introduction of dual criteria:

- a demand security criterion, aimed at developing a transmission system that facilitates conventional generation in supplying demand at times when intermittent generation is not available, and
- an economic criterion that identifies the additional transmission capability that will result in overall efficiency of generation and transmission costs.

Industry feedback on the proposals was supportive of the dual criteria approach, and of the detail of the demand security criterion. The method proposed for the economic criterion received some support, but a number of respondents expressed concern that the simplifications made to improve transparency and clarity sacrifice accuracy.

The Review Group acknowledges that, in theory, the proposed economic criterion is less accurate than other options the working group considered. However, the Review Group supports the working group's view that in practice the method will be as accurate as any alternatives, due to the significant uncertainty of the future background against which the system is planned, and that it offers a number of advantages in terms of visibility, consistency, and assessment of compliance. The review group believe that the working group's proposals currently represent the most pragmatic means of identifying appropriate system reinforcements, without introducing inaccuracies that will lead to inefficiencies.

The Review Group has discussed the proposals with the NETS System Operator to understand whether there are any potential charging implications, or issues of discrimination, associated with them. It has concluded that, as the proposals relate to the development of the Main Interconnected Transmission System, and not to the connection of generation or demand, there are no such issues.

Consequently, the Review Group recommends modifications to the NETS SQSS, that will use dual criteria to identify system capability requirements. It is the view of the Review Group that the proposals will better meet the NETS SQSS objectives of ensuring security of supply and facilitating the generation market in the most economic and efficient manner.

1. Introduction

Significant changes to Great Britain's generation capacity and technology mix are already happening, and more are expected in the coming years, including a substantial increase in the capacity of wind powered generation, and further development of other types of intermittent generation. These changes will have increasing impacts across the whole industry. One of the affected areas is the methodology used to determine the appropriate level of transmission network capability that should be developed.

The methodology for determining the required capability of the Main Interconnected Transmission System (MITS) is defined in the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS). The NETS SQSS Review Group, comprising representatives of the three GB transmission Owners (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission), is responsible for ensuring that this standard is kept up-to-date and relevant as the energy industry changes over time and technology advances.

In view of the anticipated developments in generation in the coming years, the SQSS Review Group established a working group (henceforth referred to as 'the working group') to develop proposals for the integration of intermittent generation into the NETS SQSS. The working group membership was drawn from the three TOs. In June 2010 the Review group published a consultation document[1] (referred to as 'the principles consultation document') describing the analysis and conclusions of the working group, and the Review Group's consequent recommendations for NETS SQSS changes. The principles consultation document invited the industry to comment on the general issues raised, the proposed course of action, and a number of specific questions. This consultation concerned the principles of the group's proposals, but not the details of how the proposals would be implemented in the text of the NETS SQSS. In October 2010 the Review Group issued a second consultation[2] (henceforth referred to as 'the text consultation'), describing and seeking feedback on specific NETS SQSS wording to implement the proposed method.

This report summarises the proposals, discusses the feedback on them received from industry, and makes recommendations to amend the NETS SQSS that the Review Group believe are appropriate in ensuring the transmission system will be developed in a timely and efficient manner to meet the future needs of its users.

Throughout this document, 'intermittent generation' comprises wind, solar, wave and tidal generation.

[1] The document entitled "GSR009 – NETS SQSS Consultation: Review of required boundary transfer capability with significant volumes of intermittent generation", available at http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/fundamental/Wind+Integration/

[2] The document entitled "NETS SQSS Code Drafting for Intermittent Generation", also available at http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/fundamental/Wind+Integration/

2. Scope of the proposals

The criteria of the NETS SQSS are used to determine the required capability of both the GB onshore and offshore transmission systems, from the points at which generation connects, to the points of supply to DNO networks and large, directly connected customers.

Separate criteria identify the required capabilities for the:

- circuits local to generation that provide the connection of the generation to the Main Interconnected Transmission System (MITS) (SQSS chapter 2),
- radial connection of offshore generation to the MITS (SQSS chapter 7),
- supply of demand (SQSS chapter 3), and
- MITS (SQSS chapter 4).

These separate requirements have different potential impacts on users.

Of the four categories above, those relating to local generation circuits, the connection of offshore generators, and the supply of demand, can be applicable to individual customers. Any proposals to change these criteria will need to be mindful of any potential difference they may introduce in the treatment of customers.

In developing the MITS, the aim of the NETS SQSS is to identify the level of capability that ensures adequate demand security, facilitates competition in the generation market, and is economic in overall cost (costs of transmission development versus constraint costs). The determination of the appropriate MITS capability therefore requires realistic background conditions to be set, which must take account of likely generation and demand characteristics. Consequently, in identifying the required capability, different types of generation should be considered differently in the background conditions if this affects the requirement.

This difference in treatment in setting the design background does not, however, lead to operational or commercial differences for different generation types in the utilisation of the MITS. If the capability of the MITS is insufficient to allow contracted generation to run, generation will be constrained in line with the capability. The constrained generation will be determined on the basis of market prices, and compensated through the balancing mechanism. All types of generation may be subject to such constraints: all are treated equally. It should be noted that the requirement to constrain generation does not necessarily mean that the MITS capability is insufficient, particularly if the level of annual constraints is low. A well-designed system shows a balance between costs of transmission and mean costs of constraints.

The aim of the proposals of this report is to update the NETS SQSS criteria and methodology for determining the MITS capability, based on the expected introduction of large volumes of intermittent generation. As the proposals relate solely to MITS capability, it is the view of the SQSS Review Group that they cannot introduce inequalities in the operational and commercial treatment of Generation.

3. Review of the Consultations

This section summarises the proposals included in the two consultations.

The SQSS has the dual goals of ensuring that the transmission system facilitates effective market operation and does not unduly restrict generation in securing demand. The TOs have licence obligations to ensure that their network development plans are economic. The working group has had regard for these objectives.

Eight years of historic wind data were analysed to develop an understanding of the nature of wind availability in Great Britain. This analysis indicated that there can be extended periods of very low wind speed simultaneously throughout the UK. Together with NGET's operational experience of wind powered generation, this led the working group to conclude that wind generation cannot be relied on to secure a significant proportion of demand at any given time.

At present, the capacity of intermittent generation other than that powered by wind (eg tidal, solar, wave) is very low, and little data on its performance is available. The working group did not investigate the reliance that could be placed on it to secure demand. However, the group's view was that, for the foreseeable future, this type of generation cannot be relied to secure significant levels of demand because:

- It is likely to remain at a low capacity for a number of years
- The power source for each type is not controlled, and cannot be brought on when required

Consequently, the group proposed that all types of intermittent generation are considered equally, unless evidence emerges in the future that this is inappropriate.

Previous attempts to develop a NETS SQSS criterion that simultaneously ensures both demand security and the economic integration of intermittent generation (e.g. those options presented in the GSR001 review) have not been successfully concluded.

The working group developed and proposed a dual criteria approach, in which there are separate criteria to ensure demand security, and to develop an appropriate transmission system capability to accommodate future intermittent generation.

Demand Security criterion

In the demand security criterion, intermittent generation output is included in the design background at a very low level. The principles consultation sought views on whether this level should be 0% (a figure that may be seen for only a small number of hours per year), or 5% (possibly 100 to 200 hours per year). This criterion will identify the minimum transmission capability that is required to ensure that the transmission system continues to not restrict the ability of conventional generation to secure demand, during situations when there is very little wind and high levels of demand.

Interconnectors have a large impact on system power flows, and this impact is expected to grow significantly over the next few years. The working group considered whether interconnectors could be considered reliable in ensuring security, and concluded that due to the uncertainty in trading arrangements between different markets it would be most appropriate to include them at a float condition, neither importing nor exporting, in this criterion.

The principles consultation sought views on:

- Whether it is reasonable to include a separate demand security criteria in the NETS SQSS
- The appropriate representation of intermittent generation in a demand security criterion
- The treatment of interconnectors in a demand security criterion

Economic criterion

The working group recognised that the requirement for additional transmission capability (over and above that required for the peak day demand security criterion) must be based on a year-round economic appraisal, that considers the capital cost of transmission infrastructure (T) and the anticipated cost of power system operation (O) into the future. Any method introduced to the NETS SQSS must be consistent with the objective to develop the transmission system with economy and efficiency. Three options to do so were considered:

1. A detailed year-round probabilistic cost benefit analysis (CBA), to assess the net cost associated with specific reinforcements;
2. A detailed year-round probabilistic CBA method that uses an indicative incremental price for transmission capability, and studies how the net T+O cost varies with different levels of boundary capability
3. A pseudo-CBA approach that utilises deterministic rules, that have been benchmarked against the results of a year round probabilistic CBA assessment based on indicative incremental transmission infrastructure costs (i.e. option 2). The deterministic methodology identifies the required transmission network capability, in line with that of the CBA analysis, through a simpler, more transparent process.

In analysing each of these options, it is necessary to assume values for the costs of transmission developments and system constraints. The derivation of the data used by the working group is included in appendix 5 of this report.

Specific Reinforcement CBA

The working group agreed that, in theory, a cost benefit approach based on specific reinforcement costs is the most robust form of economic appraisal. However, the nature of the technique makes its use in a planning code problematic:

- In developing robust transmission system reinforcement proposals, forecast future generation and demand backgrounds must be analysed. The uncertainty of these forecasts is very large, as discussed in the working group report, and, in the view of the working group, will be the dominant factor in the accuracy of any CBA process.
- There would be far less transparency in the transmission planning process. Many of the inputs required are commercially sensitive to industry participants (e.g. the NETS SO's view regarding the future utilisation of specific generators), and it is unlikely that the industry would want this to be released. However, without such information it would not be possible for industry participants to replicate the process to inform their own business planning. Presently, industry participants can anticipate how the capacity of the network will evolve over time in response to changes in demand and generation. This would be much more difficult with a specific-reinforcement CBA process.
- In order for Scottish TOs to undertake CBA, they will need access to GBSO operational data that underlies the system constraints. This would require a change to the SO/TO code, which currently prevents their access to this data
- There would be no clear concept of a compliant network, making regulation more ambiguous and adding uncertainty, and potentially delays, to the transmission planning and consenting process, as required by the Planning Act.

The working group therefore recommended against the use of a specific-reinforcement CBA approach in the NETS SQSS. However, the group noted the current practice of conducting a specific-reinforcement CBA on every significant transmission reinforcement to confirm its viability, and agreed that such assessments should continue.

Indicative Transmission Price CBA

An alternative to analysing the merits of specific reinforcements is to represent the transmission cost by an indicative price per MW (which varies by boundary given the varying cost of building transmission infrastructure, largely due to the different distances which need to be covered). This allows the value of T and O to be quantified for different levels of boundary transfer, and subsequently allows the T+O curves to be plotted and the minimum T+O point identified.

The assumption of an indicative transmission cost allows considerable simplification of the process in comparison with the specific cost CBA, and does lend itself to the identification of a level of compliance. As reinforcement costs can vary significantly, some accuracy is lost in this method. However, the working group included in its report the results of analysis work that shows the appropriate level of transmission system capability does not vary significantly with transmission reinforcement costs: the forecast of the generation background is much more important.

Although the group considered this option to have advantages over the specific cost CBA, it is subject to the same issues as the specific cost CBA in respect of the forecast future scenario, transparency, and data confidentiality, and is still a complex method. In the view of the working group this method is not suitable for inclusion in the NETS SQSS as a means to determine transmission system requirements.

Pseudo-CBA

As a result of the difficulties associated with the use of a CBA method, the working group developed a method that addresses many of the difficulties, without, in its view, introducing unacceptable inaccuracies. This method is based on the current practice of using deterministic rules to arrive at an answer in line with that of CBA.

The group compared a number of methods, including that in current practice, with a range of benchmark CBAs, and proposed that which best aligned with the optimum cost benefit capability across a range of scenarios and a selection of system boundaries, chosen on the basis they are the most likely to need reinforcement in the coming years. The proposed option was referred to as option 1e in the working group report.

Whilst the use of deterministic rules is inherently less accurate than a CBA method, the working group concluded that its recommended option consistently fell within the range of uncertainty associated with CBA that results from the uncertainty of the future generation background.

The pseudo-CBA method offers a number of advantages over the CBA methods:

- the method, and its parameters, are visible to all users
- there is no requirement to share confidential data between the TOs
- a capability requirement is identified, against which compliance can be assessed and need cases clearly established
- the input data for the benchmark CBA are fixed for a period, which aids the development of consistent, long term plans

On the basis of the advantages offered by this method, the working group recommended adopting the pseudo CBA approach.

The working group proposed periodic recalibration of the parameters of the pseudo-CBA. In the principles consultation it was suggested that this recalibration should be undertaken every five years. After further discussion prior to the text consultation, the working group considered that on occasion it may be necessary to recalibrate more frequently than this, and in the text specified that it be undertaken from time to time. The working group also included a modified treatment of pumped storage generation in the text consultation. This modification fixed the scaling factor for pumped storage plant to 50%, rather than allowing it to be scaled by a variable factor. This was on the basis that this scaling would ensure pumped storage generation would be considered consistently across all scenarios, better reflecting its treatment in the underlying benchmark CBA. As the variable scaling factor used in the 2020 analysis was 57%, this change will not significantly impact on the analysis included in the working group report. The revised method 1e is included in appendix 4.

4. Consultation Responses

Sixteen responses were received to the consultation on the principles, and five to the consultation on SQSS text. One of the responses to the principles consultation was marked confidential and is not discussed in this report. It will be provided to Ofgem separately.

Summary of Feedback from each Respondent

<u>Renewable UK & Fred Olsen Renewables</u>

Renewable UK & Fred Olsen Renewables submitted separate, but very similar responses.

They welcome the review and the fact that the sharing of transmission capability with conventional generation is now being made explicit. They feel that the proposed changes are long overdue, and that they represent an improvement even if more fundamental revisions to the SQSS are in the offing.

They express concern that the supporting wind generation data is based on meteorological records and not actual wind farm outputs, and request that further work in this area, including a review of the treatment of wind generation in two years (Renewable UK) and five years (Fred Olsen), is undertaken. However, they propose that for now wind generation is ignored in the demand security criterion.

They agree that the long-term forecasting of generation is fraught with difficulties, but believe that there are strong indicators as to the degree of change needed (referring to the Committee on Climate Change's work). Given the steady increase in renewable generation clearly anticipated in the UK, network reinforcements are generally more a question of 'when', rather than 'if'. Taking a risk based approach, in their view it is clear that the late provision of capability is, in general, vastly more expensive than early provision.

<u>DONG Energy</u>

DONG Energy welcomes the proposed methodology as it acknowledges that wind generation should be treated in a different way to conventional generation when considering the need for grid reinforcements. They believe that the proposals will lead to better development of the transmission system.

Magnox North

Magnox North are supportive of the proposals, considering that they will not reduce the security and reliability of the transmission system and that, in general, they will minimise costs (especially increased future BSUoS charges resulting from transmission constraints).

Drax

Drax expressed concern that the proposed method is too simplistic in assuming that conventional generation is displaced on a regional basis by intermittent generation. They also discuss issues regarding the use of lower security standards for wind generation, and in particular that this may lead to greater levels of constraint and costs.

Drax supports the drive to develop a more accurate approach to determining future network investments, and comment that it seems reasonable to ask generators to help input to the process. However, they do not support the introduction of greater user commitment, and believe this would be contrary to DECC's aim to provide greater investor certainty.

They describe the approach taken to derive the NETS SQSS criterion as uncomforting, believing that if it is adopted, regular, transparent updates of the benchmarking process will be needed.

ScottishPower Renewables

ScottishPower Renewables welcomes the review and the proposals, stating that they should be implemented without delay.

They comment that user commitment beyond two years is not feasible for generators, and should be avoided.

They support the detailed points discussed in the RenewableUK submission.

Renewable Energy Association

The Renewable Energy Association welcomes the review and supports a dual criterion approach. However, they do not support the pseudo-CBA method, on the basis that a full CBA approach may be less complicated as an enduring solution. In their view, the pseudo-CBA method could be used to narrow down options, before undertaking a full CBA to determine reinforcement proposals.

The difficulty in obtaining data for CBA is recognised by the Renewable Energy Association. They suggest that it may be appropriate for generators to submit availability data under the Grid Code. They also express the view that there should be an annual process, possibly undertaken by DECC, to determine future price predictions.

Scottish Renewables

Scottish Renewables agrees that there is a fine balance between accuracy, simplicity and expediency when deciding how to treat wind in the NETS SQSS. They feel that the analysis presented is a reasonable start, but are concerned that the desire to complete the work and fix some simplistic parameters has sacrificed too much accuracy, and may not be robust enough to withstand challenge. However, whilst CBA is a valuable tool, they do feel that full CBA for each and every reinforcement is "probably over-kill".

They conclude that the proposals are a reasonable start and may be pragmatic as a basis for a move in the right direction. They comment that further work is needed in deriving better, more robust answers, with greater debate needed on the CBA parameters and the frequency of updating them.

Centrica Energy

Centrica is concerned that the consultation fails to address the wider impacts on users that would result from the proposals, for example they feel that further information is needed on the effect of the demand security criterion on investments. Whilst agreeing that there is a balance between accuracy, simplicity and expediency, Centrica feels that the proposed approach is too simplistic, at the expense of accuracy. They comment that transmission users will generally not seek to replicate chapter 4 of the SQSS for themselves, and so transparency in the process by which the criteria have been derived are more important than transparency in the application of the criteria. Centrica proposes that all of the CBA input-assumptions are opened to industry scrutiny and debate, that sensitivity studies are run on different assumptions, and that a defined process is established to periodically agree the data to use as the basis for studies.

In response to the text consultation, Centrica noted that the text did not reflect the principle of recalibrating the benchmark CBA for the pseudo-CBA method every five years, and that the scaling factors for pumped storage and CCS generation did not match those in the principles consultation.

EDF

EDF are generally supportive of the demand security criterion, but have fundamental concerns regarding the wind integration criterion. The proposals have been developed from analysis of a selection of boundaries with two variants of the GoneGreen scenario and EDF do not believe that the results can be applied universally. In their view, the optimal scaling factors for generation are sensitive to the relative sharing of intermittent and conventional forms of generation behind each boundary, and so a single set of factors cannot be optimal for all boundaries – especially some of the more 'extreme' boundaries not reported on in the consultation document. They comment that the near and long term consequences of proposals on both transmission investment and commercial arrangements need to be investigated and reported. EDF encourage ongoing engagement with the industry in progressing these issues.

EDF also commented on the benchmarking review period included in the text, and that it was not specified as five years.

Toby Manning Limited

Toby Manning supports the dual criterion approach, but does not support the use of a low (0% or 5%) wind availability factor. In Toby's view, all generation types should be modelled according to their expected winter peak availability (he states 40% for wind generation). He also comments on the potential to relax the operational criteria, and suggests that the Interconnection Allowance component of the existing SQSS methodology, that will used in the proposed demand security criterion, should be modified.

E.ON UK

E.ON expressed concern that there has been insufficient consultation with the industry regarding the proposal, and urged more industry involvement before new arrangements are implemented.

E.ON agrees that the dual criterion approach is sensible. They accept that a CBA approach is heavily influenced by the input assumptions, but note that the pseudo-CBA approach is no less sensitive or flawed. E.ON notes that it is less risky to over-build transmission than it is to under-build, and comments that, in order to facilitate the energy market, some spare capacity is needed.

They do not support proposals to increase user commitment, believing that this transfers risk to generators, and is inconsistent with moves towards more strategic investment in networks.

Concern is also expressed about the prospect of releasing more information to the Scottish T.O's. They comment that this may contravene European regulations.

Exeter University

Exeter University expressed significant frustration at the slow rate in which this issue is being progressed, and indicated concern that the arrangements by which the transmission networks are regulated and the power markets are structured in Great Britain make it impossible for future transmission plans to be developed objectively and robustly. Exeter proposes a robust CBA process led by an independent industry body to justify investments above that required to satisfy the demand security criterion. This process should use industry agreed inputs and take account of operational measures such as the use of intertripping and weather-related operational standards. Such a process would optimise transmission investment, minimise concerns regarding objectivity, and would be consistent with the principles developed through RPI-X@20.

Durham and Heriot-Watt Universities

Durham and Heriot-Watt Universities support the view that for day-to-day internal planning purposes, a full CBA might be impractical due to its computation intensiveness and lack of transparency. For this purpose, simpler and more transparent heuristic approaches are very valuable. They note that at the industry workshop in June 2010, the SQSS Review Group stated that CBA is likely to be needed in support of any proposal over ~£50m, and believe that greater clarity is required on how this would interact with a deterministic procedure, especially if they contradict each other. In the case that the CBA result would take precedence, it would essentially be the de facto standard and the role of the deterministic rule, which needn't be included in the SQSS, would be to guide the internal development of plans.

They caution that the 'uncertainty regions' discussed in the consultation document do not imply that any boundary capability within the identified region is a reasonable candidate for implementation. In reality, a single boundary capacity is required, and, in their view, this should be selected using a risk-based approach. They comment that as underbuilding transmission brings greater regrets than overbuilding (due both to the economies of scale in transmission construction and the nonlinear dependence of constraint costs) the optimal value will likely lie towards the upper end of the defined uncertainty region.

Durham and Heriot-Watt Universities have concerns about the appropriateness of studying single boundaries independently in a CBA, and believe that further justification for this is required.

SEDG

SEDG comment that the development of an efficient, robust and transparent CBA methodology is essential for supporting network investment decisions in a system with high wind penetration. It cannot be substituted by any pseudo analysis and simplistic deterministic rules. They believe that any attempt to arrive at average-driven deterministic techniques will lead to inefficiencies. Serious consideration should be given to operational measures as an alternative to network infrastructure development. In their view, the transmission regulatory framework favours investment and asset based solutions to network problems, and it may not be appropriate that Transmission Licensees play a key role in the CBA process. The process should be led and carried out by an industry-led independent group.

In respect of cost benefit analysis, SEDG consider it to be important that multiple boundaries are optimised together, rather than considering boundaries individually.

RWE

RWE responded to the October text consultation. They expressed reservations that intermittent generation is not considered at a higher level in the demand security criterion, and suggested it may be preferable to await the availability of more metered data before progressing the proposals.

5. Discussion of feedback

The volume of feedback to the consultations was substantial. Full replies have been made to all respondents, and these and the responses are included in Appendix 2. The significant issues of comment are discussed below.

Whilst the consultation specifically concerned the NETS SQSS proposals, a number of respondents discussed issues related to proposals, that were consulted on separately, to introduce revised generation charging arrangements. In response to these comments, and those raised in the charging proposals consultation, National Grid is undertaking further analysis to support revised charging arrangements. The previously developed charging proposals focused on intermittent generation, on the basis of its limited ability to exercise its right to use the system. The updated work has established that not only intermittent, but all generation, has a differing impact under the CBA, subject to assumptions about plant operation and availability. The ability to quantify this effect and practically incorporate it within both the charging and access arrangements is being further investigated. National Grid recently reported the progress to Transmission Charging Methodologies Forum and are hoping to be able to feed this into the wider TransmiT review. The comments relating to the charging proposals are not discussed further in this report.

Whilst there was general agreement on the introduction of separate demand security and economic criteria, in most areas, opinions on the proposals were divided.

Demand security criterion

All of the respondents to the principles consultation supported the introduction of a dual criteria approach with a specific demand security criterion. In its response to the text consultation, RWE queried the need for separate criteria.

There was no consensus on whether intermittent generation should be considered at 0% or 5% of capacity in the security criterion. Toby Manning and RWE support the use of a higher factor, with Toby Manning suggesting that a figure representing typical winter availability (around 40%) would be appropriate. Some respondents commented that the contribution of intermittent generation other than wind should be kept under review, as experience may indicate that its contribution to security is higher than that for wind generation.

In general, the treatment of interconnectors at float condition (zero transfer) was supported by the respondents, although some indicated that this should be kept under review as the level of interconnection with Europe increases.

The principle of the demand security criterion is that there are likely to be significant periods of time when there is very little intermittent generation available, regardless of the seasonal average. This is supported by the wind data presented in the working group report, and by operational experience to date. Consequently the Review Group do not believe that it is appropriate to include intermittent generation at the higher levels suggested by Toby Manning and RWE. In considering whether it is appropriate to use 0% or 5%, the Review Group have been mindful of the SQSS objective on ensuring security of supply. As there is evidence that periods of no wind do occur, it is the group's view that it is sensible to adopt a cautious approach and apply a 0% scaling factor to intermittent generation. The Review Group further consider that at this time it is prudent to assume that interconnectors do not contribute to security, and to include them at float. In line with comments, the contribution of all types of intermittent generation and interconnectors will be kept under review as their total capacity increases.

Based on the analysis of the working group, the consultation feedback, and the security of supply objective of the SQSS, the Review Group recommends the introduction of a demand security criterion, in which there is no contribution from intermittent generation, and interconnectors are included with zero transfer.

Economic criterion

The consultation posed a number of questions on the different aspects of the proposals for an economic criterion. Some questions raised few comments, whereas others received a large number. Some of the respondents provided general commentary rather than addressing the specific questions.

<u>CBA Terms Considered</u>

In undertaking CBA, costs must be assigned to transmission system developments, system constraints and system losses.

Most respondents that addressed this issue were broadly happy with the approach used by the working group.

Three respondents (RenewableUK, Fred Olsen, Scottish Power Renewables) expressed the concern that the risk associated with the insufficient or late delivery of infrastructure has not been considered. Were the government to react to very high constraint costs by limiting the connection of renewable generation, this would lead to additional costs from: stranded generation assets which had been developed but could not be financed, the cost of fuel for alternative generation while wind generation lay idle, and any penalties the UK would need to pay for failing to meet its carbon budget.

Whilst it is correct that the analysis has not taken account of the risk of very late delivery of assets, leading to high constraint costs, we do not consider that this aspect significantly affects the NETS SQSS method that is chosen, but does support the need for the availability of better long term forecast data, which will allow earlier commitments to be made to reinforcements

Two respondents (Exeter University and SEDG) indicated that operational measures should be explicitly considered as an alternative to transmission infrastructure development. The Review Group consider this issue to be out of the scope of this review, and linked to longer term work on ensuring the standard leads to the development of a transmission system that meets the requirements of all of its users, in terms of cost and reliability.

CBA Timeframe and Discount Rate

The July consultation included detail of the time period covered by the CBA, and the discount rate applied.

Most respondents that addressed this topic were happy with the proposed approach.

One respondent (Durham and Heriot Watt Universities) stated that decisions under uncertainty can only be made through explicit consideration of that uncertainty using probabilistic scenario-based planning. The current SQSS methodology, and that proposed, do not explicitly apply probabilistic criterion. A change to this is outside the scope of this review. However, in constructing the background scenarios for the benchmark CBA, the likelihood of generation openings and closures are taken into account, and the backgrounds are therefore those considered most probable. The network analysis undertaken to determine reinforcements to meet the standards also include some probabilistic elements: for example circuit ratings are based on seasonal average temperatures.

Another respondent (Exeter University) agreed with the proposal to study out to 10 years, but disagreed with assuming year 10 constraint cost savings in years 11-40. Instead, they proposed establishing a criterion that a certain percentage of the value of a development should be recovered by year 10 (and potential cost savings are ignored after that point). Whilst we understand why this was proposed, we do not believe it makes a material difference to the outcome – indeed, by fixing that 'certain percentage' the two approaches can be made equivalent.

CBA Definition of Compliance

As discussed above, one issue with the specific cost CBA is that it does not define a level of system compliance: proposals can be shown to be beneficial but the optimum can only be found from considering a large number of options.

Several respondents addressed this issue and indicated that they perceived there to be no problem. Renewable UK and Fred Olsen suggest using an inability to find an economic reinforcement as the definition of a compliant network. Some respondents acknowledged that CBA does not naturally lead to a concept of compliance, but maintained that while such a concept is useful, it is not necessarily vital.

The Review Group consider that the inability to find an economic reinforcement does not indicate that the network is compliant. Such a criterion would suggest that any economic reinforcement is justified. Many reinforcements may be beneficial compared to doing nothing, particularly where a boundary has very high constraint costs, but they may result in too high or too low a level of transmission capability. Appropriate levels of system capability are found from optimising the total cost of transmission plant and constraint costs. The Review Group believes there are significant advantages to a method that identifies a compliant capability, including increased transparency of TO plans, which will better facilitate the timely development of capability to enable greater utilisation of new, renewable generation.

CBA Input Data Uncertainty

One of the major issues identified with a CBA process is the uncertainty of the input data.

Amongst the respondents, there was broad acknowledgement that there is uncertainty in CBA inputs, and in general this is considered unavoidable. It affects all forms of the economic criterion discussed in the working group report (including pseudo-CBA). It is a problem that all industry participants face.

There was a general request for greater transparency and industry involvement in the selection of CBA parameters. SEDG and REA suggested that an independent body such as DECC should lead on this. On a related issue, many respondents do not believe that it is appropriate for TOs to require greater commitment from Generators to reduce the uncertainty of future forecasts, commenting that this transfers risk to the Generators.

The Review Group agrees that the provision of future data is difficult for all industry parties. As this data is so fundamental to determining transmission requirements, the TOs intend to continue to seek ways to improve its accuracy. The establishment of an industry group to set the CBA input parameters has merit, but this will take time and delay any development of the NETS SQSS criteria. There may also be differing views within such a group, the resolution of which will also delay the development of transmission system reinforcement plans. The Review Group considers that the parameters used to date, which are consistent with those used in CBA analysis submitted to Ofgem in relation to a number of scheme proposals, are the best available at present. As discussed previously, we believe that the uncertainty of the input data is far more significant in determining the transmission system requirement than any of the simplifications introduced by the working group’s proposals.

A couple of respondents (Renewable UK and Fred Olsen) indicated that, because of the uncertainty, it would be better to err on the side of building transmission infrastructure early rather than late. The working group's analysis did not consider early or late delivery of transmission capability, but this is similar to over-building or under-building, which was analysed. Whilst in general the analysis work shown in the working group report indicates that over-building transmission capability is preferable to under-building it, the group's focus was on developing a method that consistently achieved results around the CBA optimum. One of the measures of this proximity is the cost difference, which in general will be less for an over-build than an equal level of under-build.

The respondents from SEDG and Exeter University reiterated their concern that transmission infrastructure planning should be based on steady fundamental economic drivers, and not observed market conditions. The Review Group does not support this, on the basis that historic costs are likely to be the best predictors of future costs for as long as the market mechanisms remain similar. A number of respondents stressed the importance of reducing future levels of constraints, which they will pay via BSUoS. Anticipating potential market changes was outside the scope of this review, but as and when material market changes occur the proposed rationale enables a re-basing of the pseudo-CBA approach.

<u>CBA Input Data Sharing</u>

Only one respondent (Eon) expressed concern in supplying CBA information to other TOs, and indicated that European unbundling requirements would need to be taken into consideration.

The remaining eight respondents who addressed this issue indicated that they either were not concerned, or that their concerns regarding a transparent process outweighed their concerns regarding confidentiality.

The Review Group notes these views. Although they indicate that this issue within the CBA may be readily resolvable, we believe that this will only be of benefit if the issue of data uncertainty can be progressed, making a CBA process more feasible.

<u>Pseudo CBA Scaling Factors</u>

The working group proposed the use of a pseudo-CBA process under the economic criterion. This process uses deterministic rules, and applies scaling factors to generation to set appropriate background conditions.

Dong Energy, Scottish Power Renewables, Magnox North, Renewable UK and Fred Olsen indicated their support for the change. Two commented that it effectively increases the assumed maximum contribution from wind generation from 50% at present to 70%, and that this is warranted. However, they would not want the factor to increase beyond 70%.

Several respondents, including Exeter University, SEDG, Centrica and Drax indicated that they had concerns about using a single, static set of scaling factors across GB, highlighting the inaccuracies they believe will result, and areas in Great Britain where the particular circumstances make the proposed factors inappropriate.

A couple of respondents suggested that the pseudo-CBA could form a useful internal tool for the TOs to help identify areas where a detailed specific-reinforcement CBA would be likely to identify positive-value reinforcements.

Another respondent questioned the level of justification that the working group had applied to the factors, since only the Gone Green scenario and a sub-set of boundaries were studied.

As discussed previously, the working group acknowledged that, in theory, a pseudo-CBA method would be less accurate than full CBA if the CBA was based on well defined inputs. However, this is not the case, and the analysis undertaken demonstrated that the results of the proposed method showed good consistency with the results of the benchmark CBA, always falling within the range of CBA uncertainty for a number of boundaries in two very different scenarios, and generally aligning well with the CBA optimum.

If the method is used as an internal tool only, any proposed solutions can only be assessed outside the TOs against whether they are economically beneficial, not whether they are optimal. Demonstrating that a project is the best option will be complex and time consuming, potentially delaying the development of the transmission system.

In planning the future transmission system, forecasts of the background have to be made. It is normal TO practice to plan against a limited range of best view backgrounds. The diversity of the scenarios needs careful consideration: too narrow a range may result in significant errors in plans, whilst too wide a range results in the averaging of requirements and an acceptance that they will not be optimum for any of the backgrounds. The Gone Green scenarios considered by the working group have been developed over a number of years and published and debated widely. They represent large variations (4 GW difference in transfers from Scotland) in the most credible future forecasts, and represent the TOs' views of the best planning backgrounds. The range of boundaries analysed are based on those that the TOs consider will be the main drivers for system reinforcement in the coming years.

One respondent commented that without a copy of the detailed information that the working group used to identify the scaling factors, the industry is not able to comment meaningfully on the factors. The Review Group acknowledges this concern, and, as previously discussed, will seek to involve the industry to a greater degree in establishing the input data in the future.

The scaling factors proposed for pumped storage plant in the principles and text consultation differed, and there was a lack of clarity concerning the scaling factor for CCS generation. The scaling factor for pumped storage generation was changed, from variable to a fixed factor of 50%, following fine tuning of the method between the consultations. In practice there is little difference, as the variable scaling factor originally applied was between 50 and 60%. There was no change to the CCS factor between the appendices of the principles consultation and the text consultation. However, the principles report did not indicate the CCS scaling factor that was included in the appendix.

Pseudo CBA single-boundary calibration

Two respondents noted that the pseudo CBA was only calibrated against single-boundary studies in the GSR009 report, Appendix 5. The concern is that, since a constraint action in a linear North-South system is likely to be relatively cheaply extended to solve two boundaries at once, the 'T+O' optimum capability optimising over multiple boundaries simultaneously will be at a lower capability than the single-boundary optima quoted. We have addressed this concern in a further study, reproduced in Appendix 3 of this report. This study repeats the single-boundary optima for boundaries B6 and B8 from the working group report, and performs the two-boundary optimisation. We find that the two-boundary optimum is only 200MW lower than the single-boundary optimum. This is well within the uncertainty ranges of 'T+O' optima already presented in working group report. We think that B6 and B8 form a representative pair of boundaries for this study, since they have a common driver of Scottish generation availability, but B8 contains a further 30% of the GB generation fleet over B6 in Northern England. Hence we conclude that the sub-optimality from the single-boundary optimisation performed in the June 2010 GSR009 report is only minor, and two-boundary or multi-boundary effects would in no way impact the conclusions and calibration derived there.

Pseudo-CBA Ranking Procedure

The proposed pseudo-CBA includes most available generation in the background – only that considered to be peaking plant is excluded. This contrasts with the current practice, which still forms part of the proposed demand security criterion, of including generation on a ranking order basis.

Fred Olsen and Renewable UK welcomed the reduction in subjectivity that this brings. They indicated their preference that the methodology should mainly be dependent on generation and demand volume forecasts, and not sensitive to assumed generation operating characteristics.

Exeter University indicated their preference for a ranking order based approach (basing this ranking order on "industry agreed marginal costs"), since this would better-match the way in which generation actually operates, perhaps with sensitivities based on probabilistic techniques.

Although the pseudo-CBA process is based on peak demand analysis, it is replicating year round CBA for a range of scenarios. In the CBA, all generation is included with forecast market prices, and most could be utilised, at least for short times. In comparing options for the pseudo-CBA method, it was found that a deterministic process that included the generation likely to have been used at some time in the CBA process produced the best alignment of results. The scaling rather than ranking of generation is a key component of the proposed option, and must therefore be included if this option is adopted. An added benefit of the scaling factor is the removal of the need to make judgements on the ranking order.

A couple of respondents commented that it was difficult for them to comment meaningfully as they are not fully aware of how the existing ranking order process is used, since the SQSS does not define how generators should be ranked. In the view of the Review Group, one of the merits of the proposal is that visibility of the method will be improved.

Pseudo-CBA Treatment of Interconnectors

In the demand security criterion it is proposed that interconnectors should have zero transfer in the background. In the pseudo-CBA method, a scaling factor of 100% is proposed for those interconnectors regarded as importing.

Fred Olsen, Renewable UK, and Scottish Power Renewables, oppose the proposed treatment of interconnectors in the pseudo-CBA method. Since it is highly unlikely the interconnectors will be importing at times of high wind generation, in their view they should be considered as demands.

Magnox North indicated that they supported the proposed treatment of interconnectors.

Exeter University offered some support, but commented that it might be appropriate to consider some export across interconnectors when there is significant output from intermittent generation.

The treatment of all types of generation in pseudo-CBA process is based on alignment with the CBA analysis. The translation of year round analysis to a single condition can result in backgrounds that are not intuitive. The key factor is whether the overall process produces correct results, which the Review Group believes to be the case with the proposal. Scenarios involving the interaction and correlation of interconnectors are represented in the benchmark CBA. If these interactions change in the coming years, there will need to be recalibration of the pseudo-CBA scaling factors. Periodic re-calibration is planned as part of the process.

Pseudo CBA Boundary Allowance

The pseudo-CBA process includes the use of a boundary allowance in place of the existing Interconnection Allowance.

Only one respondent (Centrica) addressed this issue. They supported the new approach if it enhances the accuracy of the technique. However, they commented that since the existing

Interconnection Allowance is not well understood, it was not possible for them to comment meaningfully on the difference.

<u>Pseudo CBA Recalibration</u>

It is proposed that the pseudo-CBA parameters are periodically re-calibrated. In the principles consultation, this was proposed every five years. In the text consultation, it was specified as being from time to time.

Several respondents indicated that benchmarking every five years would be acceptable to them. One of these respondents elaborated that input-data that is robust enough to support the need case for long-life transmission infrastructure should not be changing significantly from year to year.

The Review Group acknowledges that the text wording did not reflect the principles proposal, and that the change was not explained. The intention was to allow for more frequent review, than every five years, if required. The recommended text of this report has been further modified to say that review will take place at least every five years.

6. Conclusions

The NETS SQSS has objectives to:

- ensure security of supply
- develop an economic and efficient transmission capability
- facilitate competition in the generation market.

There is general industry agreement that the current NETS SQSS design criteria relating to the capability of the MITS are not suitable in meeting these objectives, in view of the anticipated developments in generation in the coming years. The SQSS Review group established a working group to review the criteria and propose any changes needed to ensure that they are appropriate. In practice the TOs have been informally applying a method previously developed and consulted on, but not progressed further. The formalisation of appropriate criteria is becoming increasingly important as greater levels of intermittent generation connect.

The analysis of the working group demonstrated that intermittent generation, and specifically wind powered generation, cannot be relied on to provide security of supply. Consequently the group proposed the introduction of a demand security criterion in which the contribution of wind generation is very low. The working group proposed extending this treatment to other types of intermittent generation, and to interconnectors, based on the uncertainty of their future characteristics. The group proposed that the transmission system capability identified through this criterion should be considered the minimum requirement.

In general these proposals are supported by the wider industry. The industry views did not indicate a preference for the specific level at which intermittent generation is represented in the demand security criterion. The Review Group believes that there is sufficient evidence to conclude that it should be considered at 0%.

The Review group concludes that a demand security criterion, in which there is no contribution from intermittent generation or interconnectors, should be introduced to the NETS SQSS to best meet the objective of ensuring security of supply.

The working group proposed that any additional reinforcements should be identified on an economic basis, as required by the economy and efficiency objective.

Ideally these reinforcements should be identified through a CBA process aimed at finding the economic optimum. The working group argues that such a process has a number of drawbacks, and that, due to large data uncertainties, the drawbacks are not offset by the accuracy of a CBA method.

A pseudo-CBA method has been proposed that addresses a number of the difficulties of the CBA method whilst, in the view of the working group, not introducing further inaccuracies.

Industry feedback on the use of the pseudo-CBA method was mixed. Some respondents were fully supportive, commenting that a visible process that will facilitate the timely development of the transmission system is essential to the utilisation of new, renewable generation. Other respondents were concerned that the method is inherently less accurate than a full CBA, and that full CBA should be used. There were some comments that the pseudo-CBA method could be used as an internal process, with the standard specifying that a CBA process is used. In this case, compliance with the standard could be demonstrated if no economic reinforcements can be found. There was general agreement that further work is needed to develop a mechanism for providing better forecasts of future scenarios.

The Review Group supports the working group proposal, particularly while there is significant uncertainty around future generation data. Whilst the proposal is theoretically less accurate than a full CBA method, in practice a full CBA method will not offer greater accuracy at present. The pseudo-CBA method offers a number of advantages in terms of visibility, simplicity and consistency, and is better suited to the timely development of reinforcement proposals.

The Review Group does not support suggestions that transmission system compliance is demonstrated by showing that proposed reinforcements are economically beneficial, or that no further reinforcements are economic. In developing efficient proposals, it is necessary to align as closely as possible with the optimum balance of transmission and operating costs. The Review Group believes that the analysis of the working group demonstrates that the proposals offer a pragmatic means for achieving this.

A further benefit of the proposals is that the background input assumptions are fixed for a period, aiding consistency of development of the transmission system. However, it is important that these assumptions are regularly reviewed. Review with a minimum frequency of 5 years seems an appropriate compromise between consistency, and keeping the data realistic.

In developing the transmission system, it is necessary to demonstrate a clear justification for any plans when seeking planning consent. Previous major developments have shown that clear standards, leading to a well defined requirement, aid the decision process. The Review Group consider that the visibility and consistency of the pseudo-CBA method, together with its identification of a justified, compliant capability, will provide significant benefit in informing debates on planning issues.

The criteria of the SQSS determine all aspects of transmission system development. In some areas the criteria can impact on specific users, and any modifications to them must be conscious of the potential to introduce discrimination. The proposals made by the working group relate only to the development of the MITS, and do not affect the Commercial rights or operational consideration of any individual user or type of user. Consequently, it is the view of the Review Group that the working group's proposals cannot introduce discrimination into the treatment of users.

The Review Group acknowledges the concerns regarding the use of the pseudo-CBA method, but concludes that it represents the most pragmatic means of introducing a criterion to the SQSS that will allow the visible and timely development of economically justified reinforcement plans, in line with the SQSS objective in respect of economy and efficiency.

7. Recommendations

The SQSS Review Group recommends:

A dual criteria approach is introduced to the NETS SQSS, and is used in the design of the main interconnected transmission system.

This approach shall consist of

- A demand security criterion, that establishes a minimum capability, based on zero contribution from renewable generation and interconnectors.
- An economic criterion that establishes the need for further capability. This criterion should be the pseudo-CBA method 1e, as described in the report of the Intermittent Generation working group, with the revision described in section 3 and appendix 4 of this report.

The TOs and wider industry should actively seek ways of improving the accuracy of future input data forecasts for the life of the transmission investment.

8. Changes to NETS SQSS text

The proposed NETS SQSS changes to implement these criteria are as follows:

- The requirement to meet the dual criteria is included in chapter 4, specifically clause 4.4
- New definitions have been added (demand security planned transfer condition, economy planned transfer condition, and boundary allowance) and an existing definition modified (interconnection allowance)
- The existing Appendix C, which describes the planned transfer condition, has been modified to describe the security planned transfer condition
- Minor changes have been made to Appendix D (interconnection allowance) to reflect the renumbering in chapter 4
- A new Appendix E has been introduced that describes the economy planned transfer condition
- A new Appendix F, detailing the boundary allowance for use in the economy criterion, has been added
- The existing Appendix E has become Appendix G and references have been updated throughout the document.

The revised text is shown in Appendix 1.

9. Impact on other codes

These proposals relate only to the NETS SQSS. No consequential changes are required to other industry codes.

Appendix 1 – proposed NETS SQSS text

Existing text (NETS SQSS version 2.1, 7th March 2011) is in black font
Changes are shown in red font – deletions have a strikethrough
Exceptions to this are where equations and charts are added or modified. In Appendix E and F, all of the equations and the chart are new but are in black font. In clause C6, the existing equation, marked with a strikethrough but black font, is to be replaced by the equation highlighted with a red background.
Two comments are included with yellow highlighting – these do not form part of the NETS SQSS text.

Contents

11 Terms and Definitions

Appendix A **Recommended Substation Configuration and Switching Arrangements**

Appendix B **Circuit Complexity on the *Onshore Transmission System***

Appendix C **Modelling of *Security Planned Transfer***

Appendix D **Application of the *Interconnection Allowance***

Appendix E **Modelling of *Economy Planned Transfer***

Appendix F **Application of the *Boundary Allowance***

Appendix EG **Guidance on Economic Justification**

2.4 It is permissible to design to standards higher than those set out in paragraphs 2.5 to 2.13 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

2.13 Where necessary to satisfy the criteria set out in paragraph 2.12, investment should be made in *transmission capacity* except where operational measures suffice to meet the criteria in paragraph 2.12 provided that maintenance access for each *transmission circuit* can be achieved and provided that such measures are economically justified. The operational measures to be considered include rearrangement of transmission outages and appropriate reselection of *generating units* from those expected to be available, for example through *balancing services*. Guidance on economic justification is given in Appendix ~~E~~G.

2.18 The additional operational costs referred to in paragraph 2.16.2 and/or any potential reliability implications shall be calculated by simulating the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9. Guidance on economic justification is given in Appendix ~~E~~G.

3.4 It is permissible to design to standards higher than those set out in paragraphs 3.5 to 3.10 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

3.15 The additional operational costs referred to in paragraph 3.12.2 and/or any potential reliability implications shall be calculated by simulating the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9. Guidance on economic justification is given in Appendix ~~E~~G.

4. Design of the *Main Interconnected Transmission System*

4.1 This section presents the planning criteria for the Main Interconnected Transmission System (MITS).

4.2 In those parts of the *onshore transmission system* where the criteria of Section 2 and/or Section 3 also apply, those criteria must also be met. In those parts of the *offshore transmission system* where the criteria of Section 7 and/or Section 8 also apply, those criteria must also be met.

4.3 In planning the *MITS*, this Standard is met if the design satisfies the minimum deterministic criteria detailed in paragraphs 4.4 to 4.12. It is permissible to design to standards higher than those set out in paragraphs 4.4 to 4.12 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

Minimum *Transmission capacity* Requirements

At *ACS peak demand* with an *intact system*

4.4 The *MITS* shall meet the criteria set out in paragraphs 4.5 to 4.6 under both the Security and Economy ~~the following~~ background conditions below:

Security Background

4.4.1 *generating units*' outputs shall be set to those ~~which ought reasonably to be foreseen for that demand~~ arising from the *Security planned transfer condition* described in Appendix C;

4.4.2 power flows shall be set to those arising from the ~~*planned transfer condition*~~ *Security planned transfer condition* (using the appropriate method described in Appendix C) prior to any fault, and such power flows modified by an appropriate application of the *interconnection allowance* (using the methods described in Appendix D) under *secured events*;

Economy Background

4.4.3 *generating units*' outputs shall be set to those arising from the *Economy planned transfer condition* described in Appendix E;

4.4.4 power flows shall be set to those arising from the *Economy planned transfer condition* (using the appropriate method described in Appendix E) prior to any fault, and such power flows modified by an appropriate application of the *boundary allowance* (using the methods described in Appendix F) under *secured events*;

Security and Economy Backgrounds

4.4.5 sensitivity cases on the conditions described in 4.4.2 and 4.4.4 shall comprise *generating units* with output equal to their *registered capacities* such that the required power transfers described in 4.4.2 and 4.4.4 above are approximated by selection of individual units; and

4.4.6 the expected availability of generation reactive capability shall be set to that which ought reasonably to be expected to arise. This shall take into account the variation of reactive capability with the active power output (for example, as defined in the machine performance chart). In the absence of better data the expected available capability shall not exceed 90% of the Grid Code specified capability, (unless modified by a direction of the *Authority*) or 90% of the contracted capability for the active power output level, whichever is relevant.

4.5 The minimum *transmission capacity* of the *MITS* shall be planned such that, for the background conditions described in paragraph 4.4, prior to any fault there shall not be:

4.5.1 equipment loadings exceeding the *pre-fault rating*;

4.5.2 voltages outside the pre-fault planning voltage limits or insufficient voltage performance margins; or

4.5.3 system instability.

4.6 The minimum *transmission capacity* of the *MITS* shall also be planned such that for the conditions described in paragraph 4.4 and for the *secured event* of a *fault outage* of any of the following:

4.6.1 a single *transmission circuit*, a reactive compensator or other reactive power provider;

4.6.2 a double circuit overhead line on the supergrid;

4.6.3 a *double circuit overhead line* where any part of either circuit is in the England and Wales area or the SHETL area;

4.6.4 a section of *busbar* or mesh corner; or

4.6.5 provided both the *fault outage* and prior outage involve plant in the England and Wales area, any single *transmission circuit* with the prior outage of another *transmission circuit*, or a *generating unit*, reactive compensator or other reactive power provider,

there shall not be any of the following:

4.6.6 *loss of supply capacity* (except as permitted by the demand connection criteria detailed in Section 3 and Section 8);

4.6.7 unacceptable overloading of any primary transmission equipment;

4.6.8 unacceptable voltage conditions or insufficient voltage performance margins; or

4.6.9 system instability.

Under conditions in the course of a year of operation

4.7 The *MITS* shall meet the criteria set out in paragraphs 4.8 to 4.10 under the following background conditions:

4.7.1 conditions on the *national electricity transmission system* shall be set to those which ought reasonably to be foreseen to arise in the course of a year of operation. Such conditions shall include forecast demand cycles, typical *power station* operating regimes and typical *planned outage* patterns; and

4.7.2 the expected availability of generation reactive capability shall be set to that which ought reasonably to be expected to arise. This shall take into account the variation of reactive capability with the active power output (for example, as defined in the machine performance chart). In the absence of better data the expected available capability shall not exceed 90% of the Grid Code specified capability, (unless modified by a direction of the *Authority*) or 90% of the contracted capability for the active power output level, whichever is relevant.

4.8 The minimum *transmission capacity* of the *MITS* shall be planned such that, for the background conditions described in paragraph 4.7, prior to any fault there shall not be:

4.8.1 equipment loadings exceeding the *pre-fault rating*;

4.8.2 voltages outside the pre-fault planning voltage limits or insufficient voltage performance margins; or

4.8.3 system instability.

4.9 The minimum *transmission capacity* of the *MITS* shall also be planned such that, for the background conditions described in paragraph 4.7, the operational security criteria set out in Section 5 can be met.

4.10 Where necessary to satisfy the criteria set out in paragraphs 4.8 and 4.9, investment should be made in *transmission capacity* except where operational measures suffice to meet the criteria in paragraphs 4.8 and 4.9 provided that maintenance access for each *transmission circuit* can be achieved and provided that such measures are economically justified. The operational measures to be considered include rearrangement of transmission outages and appropriate reselection of *generating units* from those expected to be available, for example through *balancing services*. Guidance on economic justification is given in Appendix ~~E~~G.

General criteria

4.11 In addition to the requirements set out in paragraphs 4.4 to 4.10, the system shall also be planned such that operational switching does not cause *unacceptable voltage conditions*.

4.12 *Transmission circuits* comprising the *supergrid* part of the *MITS* shall not exceed the circuit complexity limit defined in paragraphs B.3 to B.7 of Appendix B.

4.13 Guidance on complexity of *transmission circuits* on the *MITS* operated at a nominal voltage of 132kV is given in paragraphs B.8 to B.13 of Appendix B. Relaxation of the restrictions cited in paragraphs B.8 to B.13 may be justified in certain circumstances following appropriate liaison between the relevant transmission licensees responsible for the design of the circuits and their operation.

Switching Arrangements

4.14 Guidance on substation configurations and switching arrangements are described in Appendix A. These guidelines provide an acceptable way towards meeting the criteria of this section. However, other configurations and switching arrangements which meet the criteria are also acceptable.

7.6 It is permissible to design to standards higher than those set out in paragraphs 7.7 to 7.19 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

7.19 Where necessary to satisfy the criteria set out in paragraph 7.18, investment should be made in *transmission capacity* except where operational measures suffice to meet the criteria in paragraph 7.18 provided that maintenance access for each *offshore transmission circuit* can be achieved and provided that such measures are economically justified. The operational measures to be considered include rearrangement of transmission outages and appropriate reselection of *generating units* from those expected to be available, for example through *balancing services*. Guidance on economic justification is given in Appendix ~~E~~G.

7.24 The additional operational costs referred to in paragraph 7.22.2 and/or any potential reliability implications shall be calculated by simulating the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9. Guidance on economic justification is given in Appendix ~~E~~G.

8.4 It is permissible to design to standards higher than those set out in paragraphs 8.5 to 8.10 provided the higher standards can be economically justified. Guidance on economic justification is given in Appendix ~~E~~G.

8.15 The additional operational costs referred to in paragraph 8.13.2 and/or any potential reliability implications shall be calculated by simulating the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9. Guidance on economic justification is given in Appendix ~~E~~G.

11. Terms and Definitions

Boundary Allowance	An allowance in MW to be added in whole or in part to transfers arising out of the *Economy planned transfer condition* to take some account of year round variations in levels of generation and demand. This allowance is calculated by an empirical method described in Appendix F of this Standard.
Interconnection Allowance	An allowance in MW to be added in whole or in part to transfers arising out of the *Security planned transfer condition* to take some account of non-average conditions (e.g. *power station* availability, weather and demand). This allowance is calculated by an empirical method described in Appendix D of this Standard.
Security Planned Transfer Conditions	The condition arising from scaling the *registered capacity* of each directly connected *power station* and embedded *large power station* that is considered able to reliably contribute to peak demand security such that the total of the scaled capacities is equal to the *ACS peak demand*. Generation powered by intermittent sources (eg. wind, wave, solar) and imports from *external systems* are not included in this condition. This scaling shall follow the techniques described in Appendix C.
Economy Planned Transfer Conditions	The condition arising from scaling the *registered capacity* of each directly connected *power station* and embedded *large power station* according to the type of generation such that the total of the scaled capacities is equal to the *ACS peak demand*. This scaling shall follow the techniques described in Appendix E.
Planned Transfer Conditions (not changed but included for comparison with new terms above)	The condition arising from scaling the *registered capacities* of each directly connected *power station* and embedded *large power station* such that the total of the scaled capacities is equal to the *ACS peak demand* minus imports from *external systems*. This scaling shall follow the techniques described in Appendix C .

Appendix C Modelling of *Security Planned Transfer*

C.1 There are two techniques relevant to the determination of *Security planned transfer conditions*. For circumstances in which apparent future *plant margins* exceed 20%, the 'Ranking Order technique' should be applied. Where the apparent future *plant margin* is 20% or less, the 'Straight Scaling Technique' should be applied. These techniques are described below.

C.2 Imports from *external systems* (e.g. in France or Ireland) shall not be scaled under either of these two scaling techniques because they result from tranches of generation rather than single *power stations*.

Availability Factors

C.2 In derivation of *Security planned transfer conditions*, the registered capacities of power stations are scaled by availability factors, known as A_T, for classes T of power station. For the *Security planned transfer condition*, these factors are set as follows:

C.2.1 For stations powered by wind, wave, or tides, $A_T = 0$. This zero factor is set for the *Security planned transfer condition* so that there is confidence that there is sufficient transmission capacity to meet demand securely in the absence of this class of generation.

C.2.2 For imports or exports from / to *external systems*, $A_T = 0$.

C.2.3 For all other *power stations*, $A_T = 1.0$

Ranking Order Technique

C.3 In some circumstances apparent future *plant margins* may exceed 20%. This may arise where *NGC* has been notified of increases in future generation capacity but has not yet been formally notified of future reductions in generation capacity due to plant closures. The ranking order technique maintains the output of directly connected *power stations* and embedded *large power stations* considered more likely to operate at times of *ACS peak demand* at more realistic levels and treats those less likely to operate as non-contributory.

C.4 This is achieved by ranking all directly connected *power stations* and embedded *large power stations* in order of likelihood of operation at times of

ACS peak demand. Those *power stations* considered least likely to operate at peak are progressively removed and treated as non-contributory until a *plant margin* of 20% or just below is achieved. The output of the remainder is then calculated using the same scaling method as used in the straight scaling technique described in paragraphs C.5 and C.6 below.

Straight Scaling Technique

C.5 In this technique, all directly connected *power stations* and embedded *large power stations* on the system at the time of the *ACS peak demand* are considered contributory and their output is calculated by applying a scaling factor to their *registered capacity* proportional to an availability representative of the generating plant type at the time of *ACS peak demand* such that their aggregate output is equal to the forecast *ACS peak demand* minus total imports from *external systems*.

C.6 Thus,

$$P_{T_i} = S \cdot A_T \cdot R_{T_i}$$

Where

$$S = \frac{P_{\text{loss}} + \sum_j P_{l_j} - \sum_k P_{I_k}}{\sum_T \left(A_T \cdot \sum_i R_{T_i} \right)}$$

$$S = \frac{P_{\text{loss}} + \sum_j L_j}{\sum_T \left(A_T \cdot \sum_i R_{T_i} \right)}$$

The first equation above, with the red strikethrough, is replaced by the second equation, highlighted by a red background

and

P_{T_i} = the output of the *i*th directly connected or *embedded large power station* of *generating plant type T*

A_T = an availability representative of *generating plant type T* at the time of *ACS peak demand*

R_{T_i} = the *registered capacity* of the *i*th directly connected or *embedded large power station* of generating plant type *T*

P_{loss} = total *national electricity transmission system* active power losses at time of *ACS peak demand*

~~P_{Lj} = the active power demand at the *j*th *national electricity transmission system* demand site at the time of *ACS peak demand*~~

L_j = the active power demand at the *j*th *national electricity transmission system* demand site at the time of *ACS peak demand*

~~P_{I_k} = the import from the *k*th *external system*~~

Appendix D Application of the *Interconnection Allowance*

D.1 This appendix outlines the techniques underlying the use of the *interconnection allowance* under paragraphs 4.4.2 and ~~4.4.3.~~ 4.4.5.

D.2 The modification of the *MITS Security planned transfer condition* power flow pattern to reflect an *interconnection allowance* shall apply to the *national electricity transmission system* divided into any two contiguous parts provided that

D.2.1 the smaller part contains more than 1500MW of demand at the time of the *ACS peak demand*; and

D.2.2 the boundary between the two parts lies on the boundary between the SHETL and SPT areas, or between the SPT area and the England and Wales area, or entirely within the England and Wales area.

D.3 The *interconnection allowance* is then applied by:-

D.3.1 summing the demand and the total active power generation output (including imports from *external systems*) under the *Security planned transfer condition* within the smaller of the two parts and expressing this sum as a percentage of twice the *ACS peak demand*;

D.3.2 using Figure D.1, traditionally known as the 'Circle Diagram', to determine the *interconnection allowance* (in MW) by taking the appropriate percentage of the *ACS peak demand*;

D.3.3 finding the total active power generation output and total demand in each part of the system when applying the *interconnection allowance* or half *interconnection allowance* (as appropriate) as described in paragraphs D.4 and D.5;

D.3.4 for the conditions described under paragraph 4.4.2, proportionally scaling all the generation and demand in both parts of the system, as described in paragraphs D.4 and D.5 below, such that the transfer between the two parts increases by: first, the full *interconnection allowance* when considering the single *fault outages* in 4.6.1; and second, half the *interconnection allowance* for all other *secured events* in paragraph 4.6;

D.3.5 for the conditions described under paragraph 4.4.5 ~~4.4.3~~, proportionally scaling demand in both parts of the system and setting *generating units* with their outputs such that their totals are as described in paragraphs D.4 and D.5 below such that the transfer between the two parts increases by: first, the full *interconnection allowance* when considering the single *fault outages* in item 4.6.1; and second, half the *interconnection allowance* for all other *secured events* in paragraph 4.6.

D.4 Suppose that the two contiguous parts of the system in question are areas 1 and 2 and that area 1 exports to area 2. Let G_1 and G_2 be the total generation in areas 1 and 2 respectively and D_1 and D_2 be the total demand in areas 1 and 2 under the *Security planned transfer condition*. Let I be the transfer required in addition to that under the *Security planned transfer condition* (i.e.

the value of *I* is equal to the *interconnection allowance* or half the *interconnection allowance* as specified in paragraphs D.3.4 and D.3.5).

D.5 The additional transfer is proportionally divided between the generation and demand in the two areas as follows:

the total demands after application of the *interconnection allowance* or half *interconnection allowance* in areas 1 and 2 are

$$D_1' = k_{d1} D_1$$
$$D_2' = k_{d2} D_2$$

and the total amounts of generation in areas 1 and 2 are

$$G_1' = k_{g1} G_1$$
$$G_2' = k_{g2} G_2$$

where

$$k_{d1} = 1 - \frac{I}{D_1 + G_1}$$
$$k_{g1} = 1 + \frac{I}{D_1 + G_1}$$

and

$$k_{d2} = 1 + \frac{I}{D_2 + G_2}$$
$$k_{g2} = 1 - \frac{I}{D_2 + G_2}$$

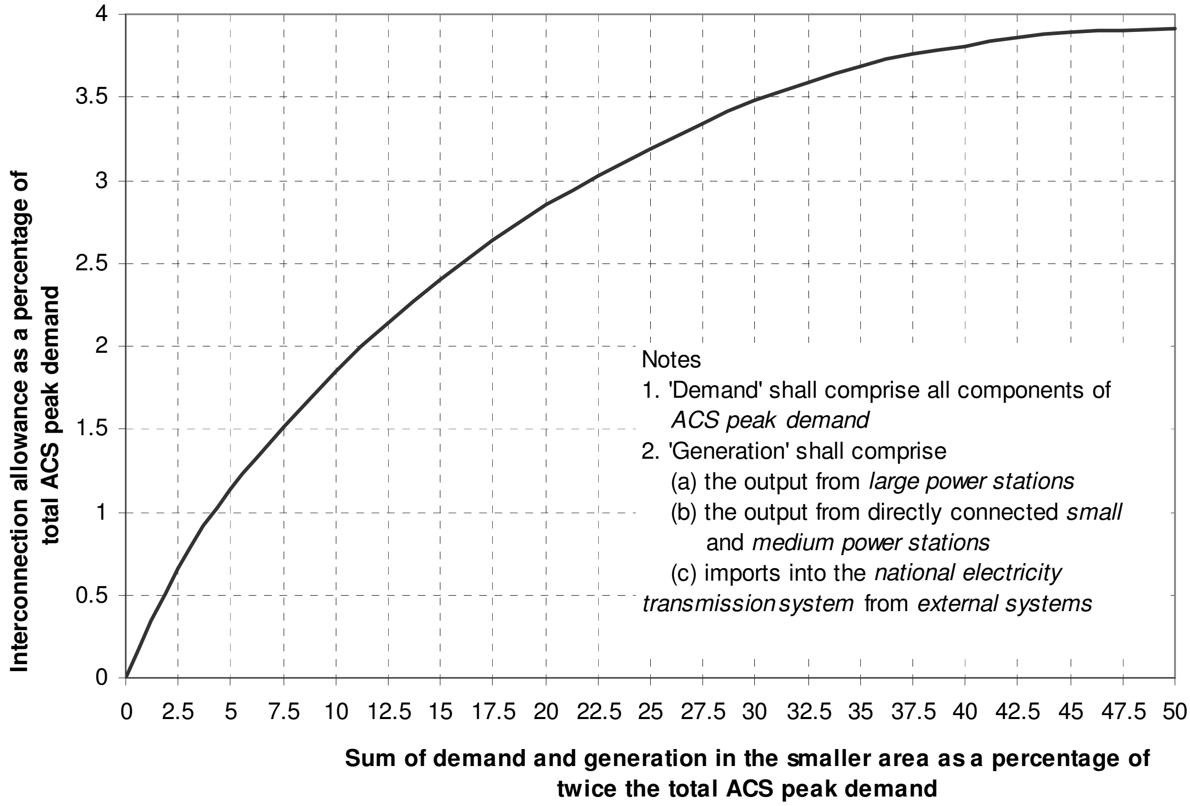


Figure D.1 *Interconnection allowance* as a function of area size (the ‘circle diagram’)

Appendix E Modelling of *Economy Planned Transfer*

E.1 For the determination of Economy *planned transfer conditions* plant is categorised in three groups:

E.1.1 non-contributory generation. This plant, such as OCGTs, does not form part of the generation background

E.1.2 directly scaled plant. The output of plant in this category is determined by a fixed scaling factor, described in E.3

E.1.3 variably scaled plant. The output of plant in this category is uniformly scaled by a variable factor that is calculated to ensure that generation and demand balance. This is described in E.5.

E.2 The NETS SO will from time-to-time review, consult on, and publish the categorisation of plant.

Directly Scaled Plant

E.3 In the *Economy planned transfer condition* the *registered capacities* of certain classes of *power station* are scaled by fixed factors, known as D_T, for classes T of *power station*. These factors are set as follows:

E.3.1 For nuclear stations, and for coal-fired and gas-fired stations fitted with Carbon Capture and Storage, $D_T = 0.85$

E.3.2 For stations powered by wind, wave, or tides, $D_T = 0.70$.

E.3.3 For pumped storage based stations, $D_T = 0.5$

E.3.4 For interconnectors to external systems regarded as importing into GB at the time of peak demand, $D_T = 1.0$

E.4 The NETS SO will review the appropriateness of these factors and revise them where necessary, based on alignment with cost benefit analysis. The period between reviews shall be no more than five years, but may be less if required.

Variably Scaled Plant

E.5 All remaining directly connected *power stations* and embedded *large power stations* on the system at the time of the *ACS peak demand* are considered contributory and their output is calculated by applying a scaling factor to their *registered capacity* such that their aggregate output is equal to the forecast *ACS peak demand* minus the total output of directly scaled plant.

E.6 Thus,

$$P_{T_i} = \begin{cases} 0 & \text{for non - contributory plant} \\ D_T \times R_{DT_i} & \text{for directly scaled plant} \\ S \times R_{VT_i} & \text{for variably scaled plant} \end{cases}$$

where

$$S = \frac{P_{\text{loss}} + \sum_j L_j - \sum_{DT}\left(\sum_k \left(D_T \times R_{DT_k}\right)\right)}{\sum_{VT}\left(\sum_n R_{VTn}\right)}$$

and

P_{T_i} = the output of the i^{th} directly connected or *embedded large power station* of generation plant type *T*

D_T = the direct scaling factor for directly scaled generation of plant type *T*

R_{DT_k} = the *registered capacity* of the k^{th} directly connected or *embedded large power station* of generation plant type *DT* in the directly scaled category

R_{VTn} = the *registered capacity* of the n^{th} directly connected or *embedded large power station* of generation plant type *VT* in the variably scaled category

P_{loss} = total *national electricity transmission system* active power losses at time of *ACS peak demand*

L_j = the active power demand at the j^{th} *national electricity transmission system* demand site at the time of *ACS peak demand*

Appendix F Application of the *Boundary Allowance*

F.1 This appendix outlines the techniques underlying the use of the *boundary allowance* under paragraphs 4.4.4 and 4.4.5.

F.2 The modification of the *MITS Economy planned transfer condition* power flow pattern to reflect a *boundary allowance* shall apply to the *national electricity transmission system* divided into any two contiguous parts, irrespective of the size or location of the parts.

F.3 The *boundary allowance* is applied by:-

F.3.1 summing the demand and the total active power generation output (including imports from *external systems*) under the *Economy planned transfer condition* within the smaller of the two parts;

F.3.2 using Figure F.1 to determine the *boundary allowance* (in MW)

F.3.3 finding the total active power generation output and total demand in each part of the system when applying the *boundary allowance* or half *boundary allowance* (as appropriate) as described in paragraphs F.4 and F.5;

F.3.4 for the conditions described under paragraph 4.4.4, proportionally scaling all the generation and demand in both parts of the system, as described in paragraphs F.4 and F.5 below, such that the transfer between the two parts increases by: first, the full *boundary allowance* when considering the single *fault outages* in 4.6.1; and second, half the *boundary allowance* for all other *secured events* in paragraph 4.6;

F.3.5 for the conditions described under paragraph 4.4.5, proportionally scaling demand in both parts of the system and setting *generating units* with their outputs such that their totals are as described in paragraphs F.4 and F.5 below such that the transfer between the two parts increases by: first, the full *boundary allowance* when considering the single *fault outages* in item 4.6.1; and second, half the *boundary allowance* for all other *secured events* in paragraph 4.6.

F.4 Suppose that the two contiguous parts of the system in question are areas 1 and 2 and that area 1 exports to area 2. Let G_1 and G_2 be the total generation in areas 1 and 2 respectively and D_1 and D_2 be the total demand in areas 1 and 2 under the *planned transfer condition*. Let B be the transfer required in addition to that under the *planned transfer condition* (i.e. the value of B is equal to the *boundary allowance* or half the *boundary allowance* as specified in paragraphs F.3.4 and F.3.5).

F.5 The additional transfer is proportionally divided between the generation and demand in the two areas as follows:

the total demands after application of the *boundary allowance* or half *boundary allowance* in areas 1 and 2 are

$$D_1' = k_{d1} D_1$$
$$D_2' = k_{d2} D_2$$

and the total amounts of generation in areas 1 and 2 are

$$G_1' = k_{g1} G_1$$
$$G_2' = k_{g2} G_2$$

where

$$k_{d1} = 1 - \frac{B}{D_1 + G_1}$$
$$k_{g1} = 1 + \frac{B}{D_1 + G_1}$$

and

$$k_{d2} = 1 + \frac{B}{D_2 + G_2}$$
$$k_{g2} = 1 - \frac{B}{D_2 + G_2}$$

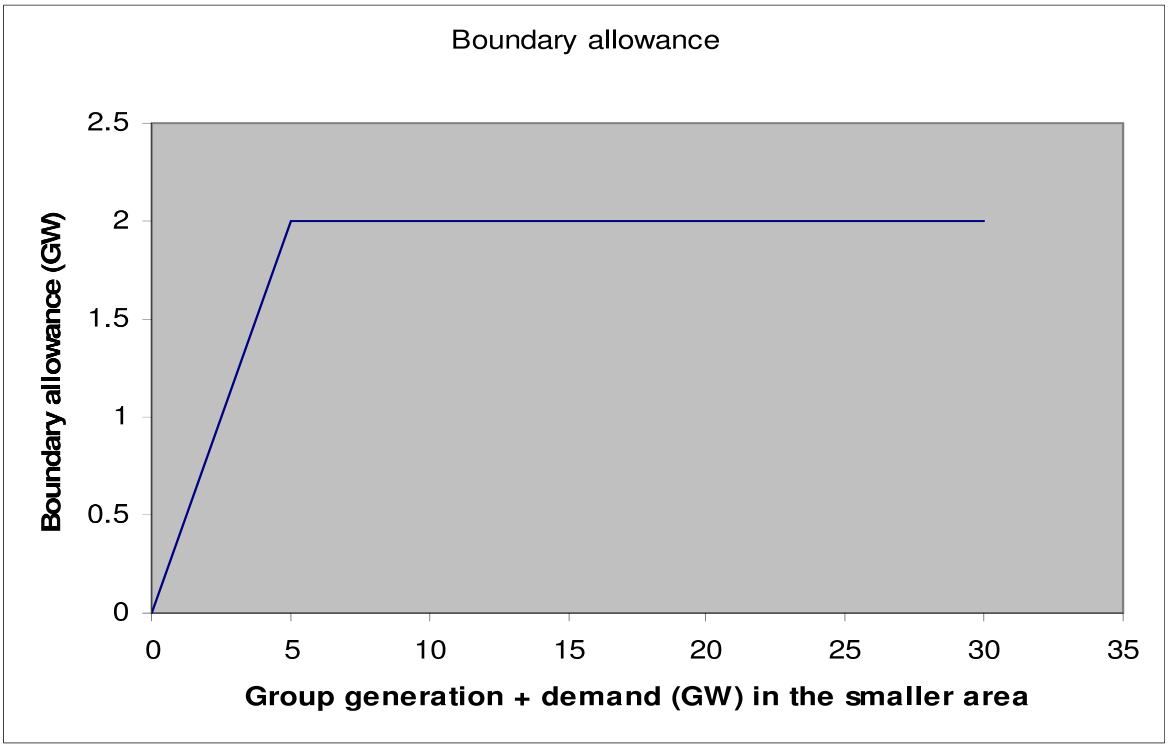


Figure F1 Boundary allowance

Appendix ~~E~~G Guidance on Economic Justification

~~E~~G.1 These guidelines may be used to assist in the:

~~E~~G.1.1 economic justification of investment in transmission equipment and/or purchase of services such as reactive power in addition to that required to meet the planning criteria of Sections 2, 3, 4, 7 or 8.

~~E~~G.1.2 economic justification of the rearrangement of typical *planned outage* patterns and appropriate re-selection of *generating units*, for example through *balancing services*, from those expected to be available under the provisions of paragraph 2.13 in Section 2, paragraph 4.10 in Section 4 and 7.19 in Section 7; and

~~E~~G.1.3 evaluation of any expected additional operational costs or investments resulting from a proposed variation in connection design under the provisions of paragraphs 2.15 to 2.18 and/or paragraphs 3.12 to 3.15 and/or paragraphs 7.21 to 7.24.

~~E~~G.2 Guidelines:

~~E~~G.2.1 additional investment in transmission equipment and/or the purchase of services would normally be justified if the net present value of the additional investment and/or service cost are less than the net present value of the expected operational or unreliability cost that would otherwise arise.

~~E~~G2.2 the assessment of expected operational costs and the potential reliability implications shall normally require simulation of the expected operation of the *national electricity transmission system* in accordance with the operational criteria set out in Section 5 and Section 9 of the Standard.

~~E~~G.2.3 due regard should be given to the expected duration of an appropriate range of prevailing conditions and the relevant *secured events* under those conditions as defined in section 5 and Section 9.

~~E~~G.2.4 the operational costs to be considered shall normally include those arising from:

- transmission power losses;
- frequency response;
- reserve;
- reactive power requirements; and
- system constraints,

and may also include costs arising from:

- rearrangement of transmission maintenance times; or
- modified or additional contracts for other services.

~~E~~G.2.5 all costs should take account of future uncertainties

~~E~~G.2.6 the evaluation of unreliability costs expected from operation of the *national electricity transmission system* shall normally take account of the number and type of customers affected by supply interruptions and use appropriate information available to facilitate a reasonable assessment of the economic consequences of such interruptions.

Appendix 2 – consultation responses

The consultation responses and Review Group replies are included in a separate, companion submission.

Appendix 3 – multiple boundary optimisation

Introduction

This paper extends our investigation into optimum ‘T+O’ ('Transmission plus Constraint') costs, which was performed under the SQSS Review of Wind. That work (ref. Appendix 5 of SQSS Consultation *GSR009*, June 2010) used the ENSG Constraints model to investigate the optimum of ‘T+O’ for single boundaries at a time; the optimum boundary capability was determined for each single boundary, assuming the rest of the GB system to be unconstrained.

There is a concern that this approach ignores the interaction between boundaries. If one boundary is not fully reinforced, then it causes some level of Constraints on the GB system; it is probably not much of an on-cost to extend these Constraint actions to resolve another boundary at the same time, and so the optimum boundary capability for multiple boundaries will be lower than the optimum for each boundary considered in isolation.

This paper investigates the above effect by determining the optimum ‘T+O’ cost for major boundaries B6 and B8 when studied together. The ‘O’ cost is determined for 2020 against the following *Gone Green* background, as was used in the *GSR009* investigation:

- **GG5c:** this is the ‘Final Gone Green 5’ scenario of 30th July 2008, as agreed between the TOs; with 11.4GW of Scottish Wind capacity in 2020.

Transmission Cost (‘T’)

Transmission cost increases linearly with increasing boundary capability. It is determined here from the following equation, which multiplies the boundary capability by a fixed price of transmission and a boundary ‘thickness’.

$T (£m) = Tran\_Price (£/MW.km) * Tran\_Thickness (km) * Bdy\_Cap (MW) / 10^6$

Figure 1: Transmission Thickness

	Thickness (km)
B4	100
B6	150
B7a	150
B8	93
B9	155
B15	60

Figure 1 shows the length of potential future Transmission lines to be laid across six MITS boundaries, were they to be reinforced (in fact, we use the average length of existing lines).

These studies use a fixed Transmission Price of £100/MW.km pa (this is the central price used in *GSR009* Appendix 5).

Figure 2: Transmission Price

Transmission Price	
100	£/MW.km

Constraint Cost ('O')

Constraint costs are determined from our usual constraint costs forecast model – here, the same version as was used in the ENSG report in 2009 – run with the GG5c 2020 background.

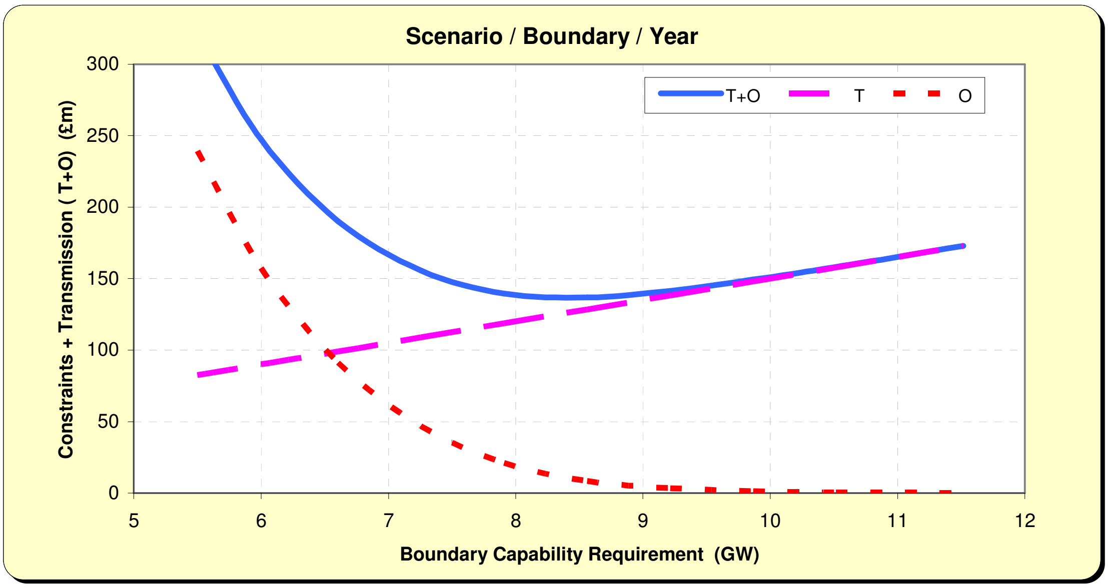
In single boundary studies, such as B6 alone, we vary the capability of B6 and set the capability of all other boundaries very high to model an unconstrained system.

As we have seen in the past, 'O' decreases approximately quadratically with increasing boundary capability.

Optimum 'T' + 'O' costs

Summing 'T' and 'O' costs for a range of boundary capabilities we can identify an optimum boundary capability – this is capability for which the 'T+O' cost is a minimum.

Figure 3: Generic T+O Cost Curve



From the generic cost curve plotted in Figure 3 we can see that inadequate capability incurs too great a constraints cost penalty despite low transmission costs, whereas too high a capability – whilst eliminating nearly all constraints costs – incurs too great a transmission cost. By inspection, the optimum reinforcement point here appears to be between 8.3GW - 8.7GW.

Single Boundary Studies

This section repeats some of the studies of Appendix 5, and determines the optimum capability for B6 and B8 boundaries individually. We use a Transmission Price of £100/MW.km and the boundary thicknesses given in Figure 1 (B6 is 150km and B8 93km).

Boundary B6

In Figure 8 below, reinforcing B6 capability to 7.7GW gives the 'T+O' cost minimum (£125.3m).

This cost comprises £115.5m 'T' and £9.8m 'O' costs. The former is calculated as 100 £/MW.km * 7.7GW * 150km.

Figure 4: B6 Optimum 'T+O'

	(T+O)	T	O
GW	**£m**	**£m**	**£m**
7.0	131.5	105.0	26.5
7.5	125.4	112.5	12.9
7.7	125.3	115.5	9.8
8.0	126.2	120.0	6.2
8.2	127.5	123.0	4.5
8.5	130.5	127.5	3.0

Boundary B8

Figure 1From Figure 5, reinforcing B8 capability to 8.5GW gives the 'T+O' cost minimum (£87.3m).

This cost comprises £79.1m 'T' and £8.2m 'O' costs. The former is calculated as 100 £/MW.km * 8.5GW * 93km.

Figure 5: B8 Optimum 'T+O'

	(T+O)	T	O
GW	**£m**	**£m**	**£m**
7.5	95.6	69.8	25.8
8.0	89.2	74.4	14.8
8.2	88.0	76.3	11.7
8.5	87.3	79.1	8.2
9.0	88.0	83.7	4.3
9.5	91.1	88.4	2.7

Two Boundary Study – B6 and B8

To address the criticism levelled at the above single boundary study approach, we seek in this section to determine the *simultaneous* required capabilities for B6 and B8 that minimise 'T+O costs'.

Transmission Cost - 'T'

The 'T' cost for B6 and B8 together is simply the sum of the costs shown individually above. Figure 6 below shows the 'T' cost of a range of capabilities across both B6 and B8 (eg. a total 'T' cost of £179.4m corresponds to 7.0GW B6 and 8.0GW B8 capability).

Figure 6: Total 'T' Cost to Reinforce B6 and B8

T (£m)		B8				
		7.5	8.0	8.5	9.0	9.5
B6	6.0	159.8	164.4	169.1	173.7	178.4
	6.5	167.3	171.9	176.6	181.2	185.9
	7.0	174.8	179.4	184.1	188.7	193.4
	7.5	182.3	186.9	191.6	196.2	200.9
	7.7	185.3	189.9	194.6	199.2	203.9
	8.0	189.8	194.4	199.1	203.7	208.4

Constraint Cost – 'O'

Constraint cost 'O' on B6 and B8 is determined by running the ENSG Constraint model for GG5c 2020 for each of our (5 x 6 =) 30 combinations of B6 and B8 capability (Figure 7). Again, other boundary capabilities are set very high to give an otherwise unconstrained system.

As expected, the Constraint cost reduces with each increment in either boundary's capability. For example, 'O' is £102.1m when B6 and B7 are 6.0GW and 7.5GW respectively. If these two boundaries are sufficiently reinforced, for example B6 to 7.7GW and B8 to 9.0GW, constraints reduce to £12.2m.

Figure 7: Total 'O' Cost after Reinforcing B6 and B8

O (£m)		B8				
		7.5	8.0	8.5	9.0	9.5
B6	6.0	102.1	96.2	93.5	92.0	91.6
	6.5	64.7	57.4	53.8	51.9	51.1
	7.0	43.7	35.1	30.7	28.4	27.5
	7.5	33.3	23.2	17.9	15.2	14.3
	7.7	31.1	20.7	15.2	12.2	11.2
	8.0	28.8	18.2	12.2	9.0	7.8

Optimum 'T+O' – approximate

Once again, combining 'T' and 'O' allows us to determine the optimum simultaneous boundary capabilities for B6 and B8. In Figure 8 below, the lowest and hence optimum 'T+O' cost is £209.5m., corresponding to B6 and B8 capabilities of 7.5GW and 8.5GW respectively.

Figure 8: Optimum T+O

T+O (£m)		B8				
		7.5	8.0	8.5	9.0	9.5
B6	6.0	261.9	260.6	262.6	265.7	270.0
	6.5	232.0	229.3	230.3	233.1	237.0
	7.0	218.5	214.5	214.8	217.1	220.9
	7.5	215.5	210.1	209.5	211.4	215.1
	7.7	216.3	210.6	209.7	211.4	215.1
	8.0	218.5	212.6	211.2	212.7	216.2

Optimum 'T+O' – precise

To find a more precise 'T+O' minimum and thus B6/B8 capabilities, more constraint runs were performed as shown in Figure 9. Capabilities were flexed more finely using 100MW increments.

Figure 9: Optimum T+O in 100MW steps

T+O (£m)		B8					
		8.0	8.1	8.2	8.3	8.4	8.5
B6	7.2	211.6	211.2	211.1	211.1	211.3	211.6
	7.3	210.7	210.3	210.2	210.1	210.3	210.6
	7.4	210.2	209.7	209.6	209.5	209.6	209.9
	7.5	210.1	209.6	209.26	209.3	209.3	209.5
	7.6	210.3	209.7	209.5	209.3	209.4	209.6
	7.7	210.6	210.0	209.8	209.6	209.6	209.8

Figure 10 to Figure 12 is a 3D graphical representation of a 'T+O' cost matrix with the optimum region shown by a light yellow circular region. The steep gradient of the plots give illustrate well the severe cost penalty for under-reinforcement.

Figure 10: 3D representation of 'T+O' Cost Matrix (View 1)

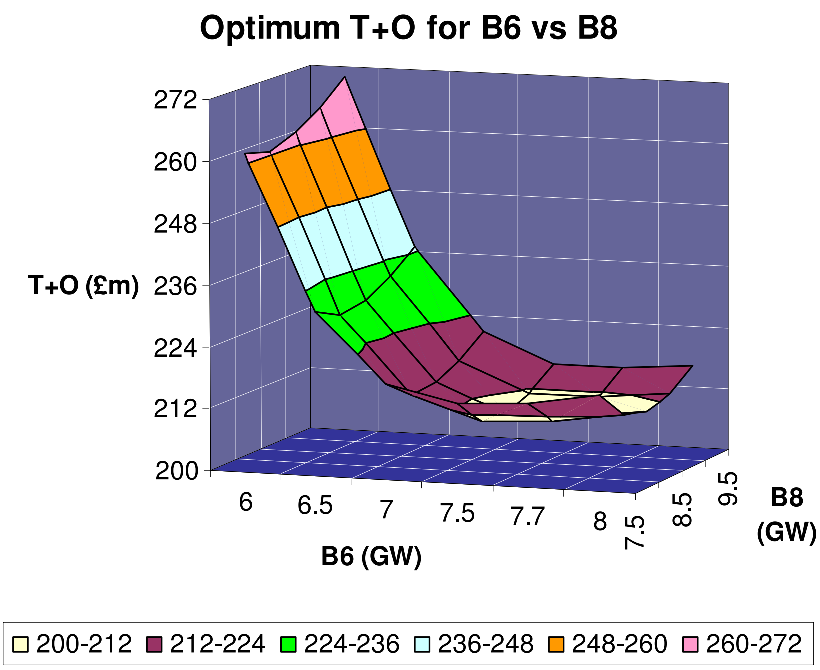


Figure 11: 3D representation of 'T+O' Cost Matrix (View 2)

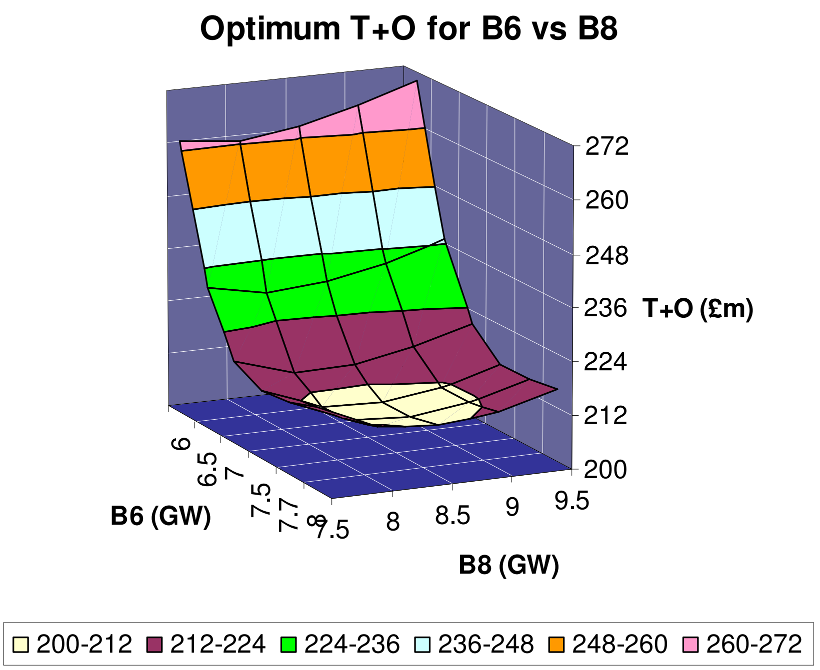
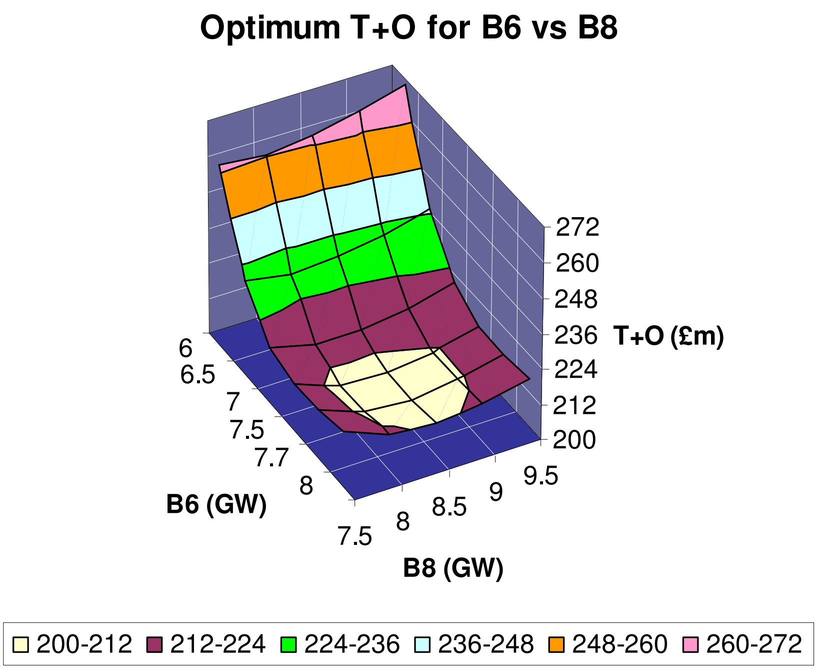


Figure 12: 3D representation of 'T+O' Cost Matrix (View 3)



<u>Discussion</u>

The optimum boundary capabilities shown in section 0 for B6 and B8 studied together are B6 7.5GW and B8 8.2GW. The single boundary optima, from section 0, are 7.7GW and 8.4GW.

Thus the 'two-boundary' effect of considering B6 and B8 together is to reduce the optimum capability by 0.2GW each from the single boundary analysis. This reduction is well less than the uncertainty regions described in Appendix 5, which are at least ±500MW on boundary capability.

Although we have not studied the 'two-boundary' effect for other pairs of boundaries, we regard our study of B6 and B8 as well representative of a general case of two GB boundaries, since

- we can say that two distant export boundaries (eg. B4 and B15) would barely correlate at all, and so the combined optimum would not be as much as 200MW away from the single optimum.
- two boundaries closer than B6 and B8 (eg. B6 and B7) might have constraints rather more correlated; the optimum in that case could easily be determined from the single boundary analysis for a boundary 300km thick. .

Transfers and constraints on B6 and B8 are both driven by the running patterns of conventional Scottish generation and the prevalence and strength of wind across Northern

Britain. Nevertheless, the boundaries have different drivers, in terms of the balance of GB generation and GB demand behind them (Figure 13). B6 only has 10% of demand and 20% of generation behind it; whereas B8 is rather more balanced (40% demand and 50% generation).

Figure 13: Optimum Capability and Constraint Cost Drivers

	Optimum Boundary Capability (GW)		**Behind Boundary**	
	Single Study	Combined Study	GB demand	GB generation
B6	7.7	7.5	10%	20%
B8	8.4	8.2	40%	50%

Thus there *is* a multi-boundary effect, in the light of which the TOs would always expect to mount a whole GB Constraint study to determine the cost-beneficial reinforcement for any one boundary. But the effect is small and well within the previously identified uncertainty region, and thus does not undermine the conclusions reached in *GSR009* on the most appropriate approach for the pseudo-CBA.

Conclusions

The conclusions drawn from this report are:

- The penalty of under-reinforcing a boundary (incurring large constraint costs) far outweighs that of over-reinforcing the boundary (incurring mild additional transmission costs).
- For an optimum 'T+O' cost, the required capability for any two or more MITS boundaries studied together might be 200 - 300MW lower than the required capability of these boundaries studied individually.
- While studying multiple boundaries, we might end up with a slightly lower optimum 'T+O' cost when compared to single boundary study – here we experienced a (£125.3m + £87.3m vs. £209.3m =) -£3.3m Δ'T+O' cost.
- The multiple boundary effect is too small to overturn the conclusions drawn in *GSR009* against the single boundary assessments.

Appendix 4 – Summary of proposed pseudo-CBA method

The method being proposed is that referred to in the working group report as method 1e, with a modification to the scaling factor for pumped storage to fix its scaling factor at 50%. This change has negligible impact on the results shown in the working group report. In that analysis, pumped storage plant was allowed to scale by a variable factor, along with coal and gas generation, in order to meet demand. In the working group's analysis, this variable factor was found to be 57% in 2020. The change is proposed as it will ensure that pumped storage is considered at 50% in all scenarios, which better reflects the year round running that will be included in the benchmark CBA. This treatment will ensure more consistent alignment of the pseudo-CBA and benchmark CBA results, for groups containing pumped storage plant, across a wider range of scenarios.

In the proposed method, scaling factors are applied as follows:

Generation that is considered non-contributory, such as OCGTs, does not form part of the generation background

Several plant types are classed as directly scaled. The output of plant in this category is determined by a fixed scaling factor, as follows:

- Nuclear powered generation, and coal and gas plant fitted with CCS equipment, is scaled by 85%

- Intermittent generation is scaled by 70%

- Interconnectors that are generally considered to import power, are scaled by 100% (other interconnectors are considered as floating or as demand)

- Pumped storage generation is scaled by 50%.

The remaining plant is classed as variably scaled. The output of plant in this category is uniformly scaled by a variable factor that is calculated to ensure that generation and demand balance.

The level of demand, and the generation pattern that results from the above application of scaling factors, determine the planned transfer across the system boundaries. The required transfer is found by adding a boundary allowance, which is similar to, but simpler than, the interconnection allowance currently applied (and applied in the proposed demand security criterion).

The results of the working group's analysis of a number of options, including that currently in practice, showed this method to be the closest to the "optimal" solution of the benchmark CBAs.

The tables below indicate the regret for each option, found by comparing both the cost and capability resulting from each method, with the benchmark CBA. The current method is method 1a. The results for two versions of the Gone Green scenario are shown.

Scenario	Regret for each option (£m)										
	1a	1b1	1b2	1b3	1b4	1c1	1c2	1c3	1c4	1d	1e
GC5a	183	144	118	101	100	349	320	238	45	201	17
GC5c	277	115	102	98	106	512	492	256	48	256	26

Scenario	Additional capability for each option (GW)										
	1a	1b1	1b2	1b3	1b4	1c1	1c2	1c3	1c4	1d	1e
GC5a	-1.4	14.0	11.3	8.9	6.5	-4.4	-4.6	-2.4	2.5	-1.8	-0.1
Gc5c	-4.0	10.8	8.4	5.9	3.7	-7.3	-7.6	-4.1	-4.4	-4.0	0.7

Note, these results are based on the working group's analysis, in which pumped storage plant scales by a variable factor.

Appendix 5 – Price Data used in calibration of pseudo-CBA method

The calibration of the rules and parameters in our proposed pseudo-CBA approach 1e directly depend on the input data to that calibration. This section supplements the description of that calibration in the June 2010 Consultation with a little more detail on the prices used in that calibration.

Price of Transmission

The central T price applied is 100 £/MW.km capital. There are a variety of methods, by which one can derive a high-level generic price of transmission suitable for this style of exercise. Three alternative such methods, for setting a transmission price in £/MW.km, are presented here:

- Ideal pricing, based on idealised reinforcements of overhead line only;
- Average pricing, based on TO revenues and installed capacity;
- Actual pricing, based on actual planned examples of network expansion.

'Ideal' Reinforcement

National Grid's recent consultations for new routes have stated that new-build overhead line can be built at a capital cost of £1.6m per km for 2x2520MVA 'L12' circuits. Thus this equates to £1.6m ÷ 5000 = £320 per MW.km capital.

We annuitise, via the relatively simple formula:
Annuitisation factor = Rate-of-return + Depreciation over 40 years + annual O&M
= 6.25% + 2.5% + 1.25% (say) = 10%
So this ideal price equates to £320 x 10% = 32 £/MW.km pa.

This transmission price is in units of MW of asset_rating. Genuine transmission expansions need to install considerably more than 1MW of asset_rating to gain 1MW of boundary_capability. In a TNUoS consultation of c.2003, we quantified this ratio (the 'security factor') at 1.8. Hence an 'ideal' transmission price of 32 £/MW.km of asset_rating corresponds to a price of 58 £/MW.km of boundary_capability.

Average Transmission Price

This method divides the total value of the current asset base, by the TW.km of asset installed. Rather than extract the RAV for each TO and then annuitise, it seems simpler to work directly from the annual charges levied on Users of the power system by the three Transmission Licensees. Of course, these charges can be said to include all sorts of items, eg relating to the financial viability of the Transmission businesses, that might not be regarded as proper constituents of a transmission price; however, it is pointless to attempt to strip these out.

The allowable revenue for the three TOs is set as follows for the current Price Control period:

	NGET	SPT	SHETL

TO revenue £m	£1093m	£156m	£50m
Circuit rating TW.km	26.7	2.7	1.55
Unit price £/MW.km pa	41	58	32

Notes:

1. The allowable revenues (source: Ofgem Price Control documents, end 2006) in fact refer to revenues for year 2006/7, in 2004/5 money. Differences to 2008/9, reflecting P0 RPI and X in Price Control language, are immaterial within the accuracy of this paper.
2. This paper works with the 'MW.km' unit of transmission capacity, under which a 2000MVA circuit, 10 km long, constitutes 20,000 MW.km = 0.02 TW.km of circuit capacity. Totals here are from the 2008/9 TNUoS charging dataset, which of course includes 132kV for Scotland; transformers have zero length, and 1 cable km = 1 km of overhead line.
3. The direct 'average' unit price is here derived by direct division of the revenue by the total TW.km. The unit price comes out reasonably close between the TOs; variations between TOs may reflect differing capital programmes, as much as any difference in intrinsic unit prices.

Some Actual 2020 Reinforcement Prices

The ENSG report of 2009 shows a number of large-scale reinforcements, which have been well costed up in outline. These costs are here convert into transmission prices, as above.

a) Scotland to England 'Incremental': This is a complex package of works, including SHETL East Coast upgrade, within-SPT works, series compensation on Cheviot, and Hark-Quer reconductoring. Total capital cost is estimated to be £479m. This provides extra boundary capability of +500MW across B4 (say 100km), and +1000MW across B6 (also say 100km); also allow for +500MW x 50km within SPT (say B5), and +500MW x 50km for Hark-Quer (sort-of B7). Thus the total expansion is 50+100+25+25 = 200 GW.km. Thus the transmission price is £479m ÷ 200GW.km = 2400 £/MW.km (capital). Or 240 £/MW.km (annual).

Note this is in units of MW of boundary_capability, not units of MW of asset_rating. Nonetheless, this does represent a notably high price for transmission expansion.

b) Scotland to England HVDC links: These are costed at £680m and £620m. They deliver, in our cost-benefit, 1800MW of both rating and boundary capability, over some 350km of cable length. (A strong advantage of HVDC, from this viewpoint, is that its controllability makes cable rating one-for-one with boundary capability.) Thus the transmission price is £650m ÷ {1.8GW x 350km} = 1000 £/MW.km (capital). Or 100 £/MW.km (annual).

c) Beauly-Denny: This delivers +900MW of extra boundary capability (from 500MW to 1400MW on B1); over a length of 190km (~ thickness of B1 + B2 + B4); at a capital cost of £350m. So the transmission price is £350m ÷ {900MW x 190km} = 2000 £/MW.km (capital) = 200 £/MW.km (annual).

d) North Wales: The total package of works proposed for the 2020 Gone Green studies costs £340m. This delivers +4000MW across 35km of Anglesey = +140 GW.km; +3000MW across the 40km Pent-Traw NW2 'boundary' = +120GW.km; and +1200MW over N.Wales NW3 export capability (Traw-Treu length = 65km) = +80 GW.km. Overall average = £340m ÷ 340 GW.km = 1000 £/MW.km (capital) = 100 £/MW.km (annual).

It can be seen that some of these large-scale reinforcement proposals deliver reinforcements at a unit price of 1000 £/MW.km (capital) = 100 £/MW.km (annual). Whereas others come out at a higher unit price, up to 2400 £/MW.km (capital) = 240 £/MW.km (annual).

e) Other E&W 2020 projects: We cannot yet quote numbers out of the 2020 proposals for East Coast etc, because we are yet to see a clear translation into boundary capabilities before and after reinforcement.

Recommendation for Transmission Price

Averaging over the large-scale reinforcements summarised above, the lowest annual price that emerges is 100 £/MW.km pa. is recommended as a central case for generic studies of transmission reinforcements. Although this value is somewhat above the 'ideal' price derived above, we note that an 'ideal' price excludes any substation works, which are inevitably required for any reinforcement.

Sensitivity studies are recommended on transmission price:

- A price of 50 £/MW.km, representing the broad average paid by GB consumers;
- A high 'actual' price of 200 £/MW.km pa, reflecting actual reinforcement costs in 'difficult' cases.

Price of Constraints

All Constraint actions, that are represented in the calibration studies of the pseudo- cost-benefit, are the acceptance of Bids and Offers ('BOAs') against the following table of Bid and Offer prices by fuel-type. (Figure 6 is reproduced from the June 2010 Consultation.)

Figure 14: Merit Order

		£/MWh	
Fuel	**Rank**	**Bid**	**Offer**
Nuclear	1	-100	n/a
Wind / Wave	2	-50	n/a
Base_Gas	3	10	40
Base_Coal	4	15	60
France	5	20	80
Water	6	23	90
Marg_Gas	7	25	100
Marg_Coal	8	30	120
PumpStor	9	75	300
Britned / Imera	10	90	360
Oil	11	100	400
Aux GT / Main GT	12	150	500

A fairly typical Constraint action in these studies is to constrain off the ‘Base_Gas’ plant in Scotland (this means Peterhead), at a Bid price of 10 £/MWh; and to replace with ‘Marg_Gas’ plant in England, at an Offer price of 100 £/MWh. Thus for most of the studies, the average Constraint price is 90 £/MWh, which follows directly from these Bid and Offer pricing assumptions.

The best description of this approach to modelling Constraint prices, and its calibration against historic experience, is given in KEMA's December 2009 report on Anticipatory investments (c. pp 70-100). There KEMA illustrate the practices involved, supplemented by some high-quality data from National Grid.

KEMA there note that the 2005-2009 average of BM Constraint prices has been some 60 £/MWh, which is milder than the 90 £/MWh quoted above. The sensitivity results presented in the June consultation, show that the GSR009 conclusions of scaling factors by class of plant are little affected by such a sensitivity.

Treatment of Losses in the Generic Cost-Benefit

The traditional exposition of the transmission cost-benefit is that:

> Cost of Transmission reinforcement should be compared against Cost of Constraints saved plus Cost of Losses saved.

Recent analysis of the Losses benefits of Anticipatory schemes has yielded highly variable results. Losses benefits for boundary flow levels just below the unreinforced rating tend to be offset by the extra Losses incurred for higher flow levels, when the reinforcement permits greater flows than the unreinforced case, for which constraints are required. Much the safest assumption is zero Losses benefit, on top of a Constraints benefit.

Accordingly, for the generic cost-benefit studies used here to support the SQSS, zero Losses benefits have been considered.

Treatment of Outage Costs in the Generic Cost-Benefit

The outage costs of constructing a reinforcement vary from very low, in the new-build case where no outages of existing circuits are required, to a sizeable outage cost, for example for the long outages required to reconductor existing circuits with higher-rating conductors. It is safest to assume zero outage cost, for a generic cost-benefit to under-pin the SQSS.