

**National Electricity Transmission System
Security and Quality of Supply Standard**

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

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Executive Summary

Significant changes to Great Britain's generation capacity and technology mix are expected in the coming years including a substantial increase in the capacity of wind powered generation. These changes will have 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 is responsible for ensuring that this standard is kept up-to-date and relevant as the energy industry changes over time and technology advances. The three GB transmission owners; National Grid, SP Transmission and Scottish Hydro Electric Transmission, are currently undertaking a fundamental review of the NETS SQSS, of which this consultation forms part. An open letter was circulated to the industry in March 2010 to detail the proposed future work plan.

The SQSS Review Group established a working group (henceforth referred to as 'the working group') to develop proposals for the integration of wind generation into the NETS SQSS. The working group comprises the three GB Transmission Owners (TOs), information has been shared between the three TOs in accordance with all licence agreements.

This consultation document presents the findings of the working group and its consequent recommendations for NETS SQSS changes. It seeks industry views on the general issues raised, the proposed course of action, and a number of specified questions. The proposals relate to the development of the MITS. A separate consultation on charging principles for intermittent generation will be undertaken shortly. The connection arrangements for all types of generation are being considered under the fundamental review: initial principles have been subject to industry consultation but further work is needed.

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 working group has therefore had regard for both of these objectives.

The working group initially analysed eight years of historic wind data to develop an understanding of the nature of wind availability in Great Britain. This analysis showed that wind generation cannot be relied on to secure demand at any specific time. Consequently the working group proposes that a separate demand security criterion be included in the SQSS, which assumes wind generation output to be at a very low level. This criterion will identify minimum transmission capacity required to ensure that the transmission system does not restrict the ability of conventional generation to secure demand during periods when the wind is slight.

It is also recognised that economic analysis will need to be undertaken to identify the requirement for additional transmission capability over and above that required for the peak day demand security criterion to facilitate the transportation of intermittent (wind & tidal) generation and effective market operation. Three options to do so have been considered.

- Two involve year round probabilistic cost benefit analysis (CBA) and are:
 - a CBA approach to assess and compare the net cost associated with specific reinforcements;
 - a CBA method that uses an indicative incremental price for transmission capability and can be used to define required transmission network capabilities
- The third is a pseudo-CBA approach that utilises deterministic rules that have been benchmarked against CBA results to define required transmission network capabilities.

The working group accepts that a detailed CBA approach with known input values which have low volatility should give the most accurate results. However, without a process that reveals these input values, there is a requirement to rely on forecast data. Given the large number of input variables and the inherent variations and uncertainties encountered when considering a 40 – 60 year asset lifespan, the working group believes that any additional accuracy offered by a detailed CBA process is negated by an inability to accurately forecast these input values. Pursuing the CBA approach with the backdrop of an uncertain forecast means that:

- The optimum reinforcement identified is sensitive to variable input factors such as the assumed operating behaviour of power stations
- Variations in forecast input factors over time will lead to inconsistent identification of the appropriate reinforcement needs
- The process would not be transparent and would be difficult for external parties to understand and apply to undertake independent analysis
- To meet their licence obligations the vertically-integrated Scottish TOs would require access to commercial generator input assumptions to apply the methodology to their networks
- The process does not lend itself to identifying initial development proposals

Two other options were also considered: an economic analysis that uses an indicative incremental price for transmission capability, and a pseudo-CBA approach that utilises a deterministic methodology to consistently and transparently produce results that align with a CBA. To ensure the continued accuracy of a pseudo-CBA methodology, it is proposed that it is periodically benchmarked against a reasonable economic analysis: the working group recommends a review every five years. A number of possible implementations of a pseudo-CBA methodology have been examined and each has been benchmarked against a probabilistic CBA. The working group has identified an option that it believes can be used with no practical reduction in accuracy compared with a CBA approach. The working group therefore recommends this approach for incorporation into the NETS SQSS standard.

As discussed above, and regardless of the option selected, there remains much uncertainty in future generation openings, closures, and individual power station prices, and therefore the level of transmission capacity required. In order to minimise this uncertainty, it is recommended that the industry seeks to develop processes by which these factors can be agreed with network users and fixed for defined periods to improve the transparency and consistency of transmission network planning.

Industry views on the principles and proposals put forward in this document, and responses to the questions raised throughout the report and detailed in section 11 are sought by July 9th 2010. Details of how to respond to this consultation are included in section 12.

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1 Introduction

The National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) Review Group is responsible for ensuring that the NETS SQSS is kept up-to-date and relevant as the energy industry changes over time and technology advances.

A number of reviews of specific aspects of the SQSS have been initiated in recent years. These reviews have included consideration of the integration of intermittent generation in the standard. Proposals were consulted on across the industry in early 2008 as part of the GSR001 review. These are discussed in appendix 4 of this report. At the time of the GSR001 consultation it was recognised by the Transmission Owners, Ofgem, and the wider industry that a broader review of the NETS SQSS was needed, and so the SQSS Fundamental Review was established. The question of intermittent generation integration was then referred to the fundamental review for consideration alongside other matters.

Substantial progress has been made by the Fundamental Review and a number of changes to the NETS SQSS were proposed in an industry consultation document issued in April 2010. However, the complexity and challenge presented by the fundamental review meant that the subject of intermittent generation was not significantly progressed. This consultation document can be found here: <http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/fundamental/April+2010+Consultation/April+2010+Consultation.htm>

In an open letter to the industry, published on 30 March 2010, the SQSS Review Group outlined its workplan for the ongoing review of the SQSS. This letter recognised the increasing volume of wind and other forms of intermittent generation currently under development and the consequent pressing need to introduce the appropriate treatment of such generation into the planning standard. To this end a working group (referred to as “the working group” in this report) was established to develop criteria suitable for identifying the required capability of the Main Interconnected Transmission System. The working group was tasked with developing proposals to be put to industry consultation throughout June 2010, and reporting to Ofgem with recommendations in July 2010. The open letter is available here: <http://www.nationalgrid.com/NR/rdonlyres/CFF78A12-949C-4D87-B8FD-F51FE156D9E6/40409/SQSSOpenLetter300310.pdf>

This consultation report describes the analysis undertaken by the working group, the results obtained, the working group’s appraisal of the various options, and the working group’s preferred approach. The industry’s views on the general principles, recommended approach, and a number of specified questions are welcomed and encouraged. The proposals and comments will form the basis of the SQSS modification recommendations that will be submitted to Ofgem.

Responses to this consultation are required by 9th July 2010 to enable the timely submission of the report to Ofgem. Guidelines for providing feedback are provided in Section 12.

2 Drivers for change

The existing NETS SQSS criteria which relate to the required capability of the transmission network were developed at a time when:

- Generation plant performance was predictable and controllable i.e. it was generally able to provide rated power when required
- The total installed generation capacity was maintained at approximately 120% of peak demand. This level is considered sufficient to meet demand allowing for reasonable plant breakdown or unavailability

Recent years have seen significant changes in the composition and behaviour of Great Britain's generation fleet and it is expected that the pace of change will increase in coming years. Factors driving the changes include government plans to deliver policy that facilitates investment in approximately 35GW of new renewable generation in the UK between now and 2020 to allow the UK to meet its climate change targets. Consequently, large amounts of renewable and other low carbon generation are anticipated to connect to the power system, as well as a significant 13.7GW of plant closures. This has two impacts:

- The location of new generation away from the main load centres will necessitate significant network reinforcement.
- Much of this renewable generation will be intermittent in nature.

The existing NETS SQSS method, described in appendix 2, does not differentiate between conventional and intermittent generation. It is widely accepted that the level of transmission required for intermittent generation is not the same as that required for the same capacity of conventional generation.

An approach that made allowance for intermittent generation was developed by the TOs in 2004 and has been adopted for transmission system development. It was not specified in the NETS SQSS.

The GB SQSS Review Group initiated a NETS SQSS review in 2007, with a view to developing criteria that addressed the issue of planning for generation that includes both conventional and wind powered. This review looked at several approaches, including that in use at the time (referred to as approach 1a). Proposals for the review were consulted on in January 2008 (GSR001) but were not progressed further.

as the subject was included in the Fundamental Review that was starting at the time. An overview of the GSR001 review is given in appendix 4.

The TO method in use at the time of GSR001 was retained and is used for the majority of boundary analysis at present. It is referred to as the “current method”.

The current method has some advantages:

1. It is transparent and yields consistent, repeatable results.
2. It specifies an unambiguous required capability against which TO compliance can be assessed.

However, it is acknowledged that the method has some significant weaknesses:

1. The method is not well understood, particularly outside the TOs
2. The scaling factors it utilises have not been robustly justified (although some work was done to identify these factors and is documented in the GSR001 report)
3. The appropriateness of the existing process for ranking generation (based on the historical behaviour of generation, as described in the Seven Year Statement) is questionable when studying power system scenarios where the proportion of intermittent generation is considerably higher than present levels. Additionally, the outcomes of this methodology become increasingly sensitive to the generation ranking order as an increasing proportion of generation is classified as being 'non-contributory' as the total volume of generation capability increases.
4. The NETS SQSS criteria do not explicitly specify the parameters to be used in the method

In view of these concerns, following discussion with Ofgem, the NETS SQSS Review Group established this further review of transmission planning criteria.

3 Scope of current review

The terms of reference of the working group are included in appendix 1 and are summarised as:

Determining and making proposals on an appropriate NETS SQSS criterion which defines the minimum capability of MITS boundaries in the presence of a significant volume of intermittent generation.

To this end, the working group should:

- establish the current SQSS requirements and TO practices relating to modelling wind generation
- identify any issues with the current requirements and practices
- review previous work done in this area and any conclusions and recommendations made
- if necessary, identify and consider, appraise and justify additional options

The working group should not:

- make proposals relating to the deterministic nature of the system events currently considered within the SQSS
- consider the use of demand management in managing wind generation variability

It should be noted that this working group has not considered commercial charging arrangements that may be applied, taking into account different generation types. These arrangements are being developed in parallel and it is expected that they will be put to industry consultation shortly, prior to the close of this consultation.

The working group proposals relate to the development of the Main Interconnected Transmission System. The group has not considered the issue of local generation connections. The recent Fundamental Review consultation included some proposals on the principles of local connections, but noted that further work in this area is needed. It is expected that this further work will address the connection of intermittent generation.

4 Understanding Wind Generation behaviour

4.1 Wind Data

In order to better define how the contribution from wind generation should be considered within the SQSS review, an important early activity of the working group was to study historical wind data to help identify wind generation scenarios that can be considered credible.

Historical wind data, covering an eight year period from 2000 to 2008, was provided to National Grid by consultants Pöyry. This wind data showed the hourly *capacity factor* recorded at 37 wind measurement points located throughout GB and Ireland. The *capacity factor* represents the per unit output of a wind farm if it was to be located at one of these measurement points.



Figure 1 – wind measuring locations

For the purposes of this analysis the wind farms included in National Grid’s Gone Green 2030 scenario were matched up against the closest corresponding Pöyry measurement point. This resulted in a total installed wind capacity of 27.8GW across Great Britain. The hourly GW output of each wind farm was calculated by multiplying the hourly capacity factor at a measurement point by the corresponding wind farm capacity.

4.2 Output Levels

The first stage of wind data analysis examined how many hours the total system wind output was above 40% and 60% of capacity in order to give an indication of a credible level of wind output. It should be noted at this point that the results shown below are only for the winter period of the year (1st November to 31st March), a total of 3624 hours as opposed to 8760 for a full year.

Figure 2 shows the distribution across the eight study years. Tables 1 and 2 show the total number of hours when GB wind output is greater than 40% and 60% respectively

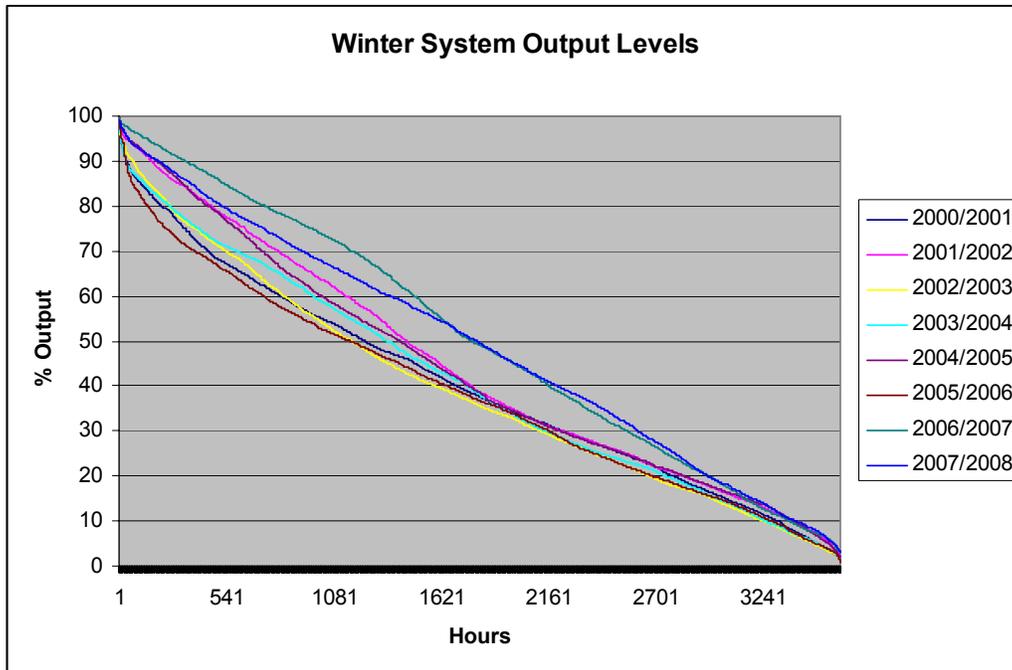


Figure 2 – Total wind output levels (winter period)

Year	Winter Hours > 40% Output	% of Winter > 40% Output
2000/2001	1696	46.8%
2001/2002	1772	48.9%
2002/2003	1589	43.8%
2003/2004	1750	48.3%
2004/2005	1754	48.4%
2005/2006	1651	45.6%
2006/2007	2163	59.7%
2007/2008	2206	60.9%
Average	1823	50.3%

Table 1 – Hours total wind output is above 40% (winter period)

Year	Winter Hours > 60% Output	% of Winter > 60% Output
2000/2001	811	22.4%
2001/2002	1141	31.5%
2002/2003	827	22.9%
2003/2004	973	26.8%
2004/2005	1019	28.1%
2005/2006	728	20%
2006/2007	1483	40.9%
2007/2008	1359	37.5%
Average	1043	28.8%

Table 2 – Hours total wind output is above 60% (winter period)

As well as high wind conditions it is also important to understand how often low wind output conditions occur, i.e. how often will there be little or no wind generation on the system. Using the same historical wind data the number of hours when the total system wind output was below 10% was determined.

Output levels below 10% were subdivided into three categories; 0% - 2%, 2% - 7% and 7% - 10%. Table 3 shows the number of hours recorded at these output levels for each year and the resulting averages. Both the winter period (3624 hours) and the annual total (8760 hours) are shown.

	Winter (No. of Hours at Output)				Annual (No. of Hours at Output)			
	0% - 2%	2% - 7%	7% - 10%	Total	0% - 2%	2% - 7%	7% - 10%	Total
2000/2001	9	190	109	308	33	851	675	1559
2001/2002	1	108	121	230	75	593	521	1189
2002/2003	5	234	146	385	17	722	656	1395
2003/2004	5	220	152	377	19	685	634	1338
2004/2005	2	131	99	232	37	666	557	1260
2005/2006	8	207	131	346	9	602	1104	1715
2006/2007	0	105	150	255	43	721	650	1414
2007/2008	0	88	138	226	4	504	562	1070
Average	4	160	131	295	30	668	670	1368

Table 3 – Hours total wind output is below 10%

4.3 Correlations

In order to assess the diversity of wind output that may be present across the GB system the output from Scottish and English / Welsh wind fleets were compared to find the degree of correlation between the two.

The following tables show the average aggregated output from Scottish wind farms compared against the average aggregated output of English and Welsh wind farms across the 8 years of data provided. The wind farm outputs from Scotland and England and Wales was sorted into 10% brackets hence giving 100 potential system conditions (e.g. Scotland 0-10% when England and Wales 60-70%). Table 4 shows the number of hours for which each condition occurred. Table 5 shows the number of hours converted to a percentage of hours in year.

4.4 Conclusions on wind data

Comparing Scotland against England and Wales, cells highlighted in red show the highest number (and hence highest correlation) in a range, with yellow cells showing the two second highest values. It can be seen from the table that the outputs broadly correlate across the diagonal indicating a fairly high degree of correlation between the Scottish and English outputs. There is a bias towards high outputs from the English wind farms which may be due to a high proportion of these being offshore and hence subject to more consistent high wind conditions.

As part of the GSR001 consultation a number of methods for planned transfer conditions including wind were proposed. One of these methods (1b1) proposed that wind generation in exporting groups should be included at 60% output, with wind in importing groups at 5% output. The comparison of wind data in Scotland with that in England and Wales in the tables above shows that:

- the Scottish wind fleet output is between 60% - 100% for, on average, 1099 hours per annum
- for only 16 hours (i.e. 0.18% of the year) of this time the English wind fleet is generating at 0% - 10%.

This comparison considers correlations across the extremes of the GB system and implies that there will not be significant differences in percentage wind output across any of the GB boundaries. On this basis the group concludes that the condition described in method 1b1 is too rare to form a credible basis of a planned transfer condition¹.

¹ Note that method 1b1 was developed on the basis of maintaining constant “percentile of boundary transfer” at winter peak demand under N-1 and N-D conditions; i.e. the method attempted to re-calibrate the existing procedure rather than being representative of an actual wind generation output condition. Also, only onshore wind generation was considered when method 1b1 was first proposed.

It can also be seen from the results of the low wind output analysis that wind output can be below 10% for significant periods of the year. From the data, the group concludes that the output is in the range 2 – 7% for a sufficient percentage of the year (8% on average) to warrant consideration when determining the level of transmission required in facilitating demand security.

		England										
		0-10%	10-20%	20-30%	30-40%	40-50%	50-60%	60-70%	70-80%	80-90%	90-100%	Totals
Scotland	0-10%	806	536	415	243	127	76	49	28	12	8	2300
	10-20%	412	448	310	233	158	112	78	59	29	24	1862
	20-30%	167	259	229	177	132	107	78	63	39	30	1280
	30-40%	82	155	139	128	96	88	76	75	51	42	930
	40-50%	48	92	83	83	85	83	79	63	59	52	727
	50-60%	24	48	57	67	61	68	62	58	56	63	563
	60-70%	8	30	34	47	40	53	52	48	59	72	443
	70-80%	5	15	18	25	25	30	43	42	45	77	325
	80-90%	2	5	8	9	12	19	23	31	40	88	237
	90-100%	0	1	1	5	5	6	8	8	17	43	95
Totals		1554	1589	1294	1017	741	640	547	474	407	498	

Table 4 – Wind Output Correlation (hours per annum)

		England										
		0-10%	10-20%	20-30%	30-40%	40-50%	50-60%	60-70%	70-80%	80-90%	90-100%	Totals
Scotland	0-10%	9.20%	6.12%	4.73%	2.78%	1.45%	0.86%	0.56%	0.32%	0.14%	0.09%	26.25%
	10-20%	4.70%	5.12%	3.54%	2.66%	1.80%	1.28%	0.89%	0.67%	0.33%	0.27%	21.25%
	20-30%	1.90%	2.96%	2.62%	2.01%	1.51%	1.22%	0.89%	0.71%	0.45%	0.34%	14.61%
	30-40%	0.93%	1.76%	1.58%	1.46%	1.09%	1.01%	0.87%	0.86%	0.59%	0.48%	10.62%
	40-50%	0.55%	1.05%	0.95%	0.95%	0.97%	0.95%	0.90%	0.72%	0.67%	0.59%	8.30%
	50-60%	0.28%	0.55%	0.65%	0.76%	0.70%	0.77%	0.71%	0.66%	0.64%	0.72%	6.43%
	60-70%	0.10%	0.35%	0.39%	0.54%	0.46%	0.60%	0.59%	0.55%	0.67%	0.82%	5.06%
	70-80%	0.06%	0.17%	0.21%	0.28%	0.28%	0.34%	0.49%	0.48%	0.51%	0.88%	3.71%
	80-90%	0.02%	0.06%	0.09%	0.11%	0.14%	0.21%	0.26%	0.35%	0.46%	1.00%	2.70%
	90-100%	0.00%	0.01%	0.02%	0.06%	0.05%	0.07%	0.09%	0.10%	0.19%	0.50%	1.08%
Totals		17.73%	18.13%	14.77%	11.61%	8.46%	7.31%	6.25%	5.41%	4.64%	5.69%	

Table 5 – Wind Output Correlation (percentage per annum)

5 Dual criteria approach

The current methodology for determining the required MITS capability is based on a peak day capacity study incorporating the following assumptions:

1. a peak demand level,
2. a merit (ranking) order approach to determine contributory generation (ie. that which is most likely to run, either at full or part load, to meet the demand), and then
3. scaling generation to meet demand.

In this methodology wind generation is normally included in the contributory generation, displacing some conventional generation. As the capacity of wind generation increases, its influence on system power flows and consequent network development will increase, and correspondingly the influence of conventional generation on network development will decrease.

In theory this could eventually lead to a transmission system that is incapable of accommodating the flows that would result from a generation scenario in which little or no wind is available. In other words, the methodology does not maintain the current level of demand security at times of low wind. The wind data analysis described in section 4 shows that periods of little or no wind do occur for notable periods each year, giving a significant probability that a scenario in which only conventional generation is available to meet a peak demand condition will arise.

To ensure that sufficient transmission capacity is built for such circumstances the working group proposes that a criterion be included in the Standard that will determine the transmission capacity required to allow demand to be met predominately by conventional generation. This will be referred to as a demand security criterion.

In addition to ensuring demand security, the Standard also has the objective of determining the required transmission capacity to facilitate the effective operation of the generation market, providing a transmission system that leads to the overall most economic supply of electricity on a year round basis. This objective will necessitate transmission system development beyond that needed to ensure demand security at peak when intermittent generation for demand security is assumed to be at very low levels. The working group therefore proposes that a separate 'intermittent generation' economic criterion, based on minimising the net cost of electricity supply to consumers, is also included in the standard.

6 Demand security criterion

The existing NETS SQSS requirements were developed such that, against a background of conventional generation, the “right” level of demand security is provided. A review of the standards in the mid 1990s concluded that, at the time, the degree of security was

appropriate. It is outside the scope of this working group to further review the appropriate level of demand security. Therefore, the working group's proposals aim to preserve the same demand security that was envisaged when the standards were developed.

On this basis, the proposed criteria will replicate the existing requirements with the addition that they will stipulate that intermittent generation should be included at a low value. A scaling factor of 0% for intermittent generation is simplest to articulate and implement, but analysis of the wind data supports the inclusion of wind generation at 5% of Registered Capacity. This is because, against the Pöyry dataset, the GB 2020 wind fleet will be at 0-2% total output for an average of only 4 hours per year; whereas it will be at 2-7% output for an average of 160 hours per year. The working group's view is that there will be limited practical difference if a factor of 0% is used (especially given the scale of most transmission reinforcements), but requests industry views on the proposed 5% level at which to include intermittent generation in a demand security assessment. Wind generation is expected to account for the vast majority of Great Britain's intermittent generation for the foreseeable future.

The scope of the working group does not include consideration of interconnectors. However, the group has debated how they should be treated in the demand security criterion and proposes that interconnectors are considered to be at "float" (i.e. zero power transfer) in the demand security analysis. This is on the basis that historic behaviour of the existing interconnectors has been inconsistent on the very highest peak day demands and the group believes that no net flows between different nations when generation capacity is at an absolute premium is a reasonable assumption.

It should be noted that as the volume of wind generation increases the capacity of conventional generation may fall below 120% of peak demand. In such cases the ranking order process will not be needed and scaling factors used within the analysis to match generation to demand will rise above 83%. Were the total volume of generation (with wind at 0-5%) to fall below 100% of demand, it is proposed to allow the scaling factor to rise above 100% to ensure that generation continues to meet demand. This is equivalent to assuming that additional generation will be constructed to cover the deficit, distributed uniformly throughout Great Britain. This is only expected to be encountered during the later years of medium-long term generation scenarios.

As this criterion is aimed at the provision of demand security it is envisaged that it will prescribe a minimum transmission requirement and will not be subject to further economic justification.

Consultation Question: *The group seeks industry views on the principle of a demand security criterion, the appropriate wind scaling factor, and the treatment of interconnectors. These issues are the subject of question 1 in section 11.*

7 Economic Intermittent Generation criterion

The transmission system that will result from the application of the demand security criteria will not always be sufficient to accommodate the anticipated large volumes of new intermittent generation, particularly in and around Scotland where wind capacity is expected to significantly exceed the capacity of existing conventional generation. Without additional transmission development a high percentage of potential wind generation will be constrained off (generation paid not to run) for a significant proportion of time, wasting an opportunity to reduce greenhouse gas emissions and incurring significant constraint costs. An economic appraisal would achieve a balance between the cost of new transmission infrastructure and the cost of operating the system.

Any transmission capacity developed beyond the minimum demand security requirement will require some form of economic justification. The working group therefore propose that criteria are included in the NETS SQSS that identify economic development of transmission beyond that needed for demand security.

The working group reviewed the approaches considered by GSR001. It was agreed that approaches 2, 3 and 4 would not be considered further as:

- Approach 2 (demand security based) results in lower reinforcement requirements than are likely to be economic when constraints are considered
- Approaches 3 and 4 (based on maintaining current performance) were not yet sufficiently well developed to form the basis of a proposal within the timescales available to the working group, and initial experience using the proposals indicated that their ability to identify the optimum transmission system capacity was inconsistent.

The full GSR001 report is available here:

http://www.nationalgrid.com/NR/rdonlyres/B6B8CABD-6D2C-4D1E-A48F-51789CA93484/22606/GBSQSS_Review_for_Onshore_Intermittent_Generation.pdf

Three approaches have been considered further by the working group. These include options 1 and 5 of GSR001.

Two approaches involve year round probabilistic cost benefit analysis (CBA) and are:

- a CBA approach to assess and compare the net cost associated with specific reinforcements ('specific reinforcement CBA');
- a CBA method that uses an indicative incremental price for transmission capability and can be used to define required transmission network capabilities ('indicative transmission price CBA')

The third is a pseudo-CBA approach that utilises deterministic rules that have been benchmarked against CBA results to define required transmission network capabilities ('pseudo CBA' approach) .

Each method aims to identify the transmission boundary capabilities and/or reinforcement options that minimise the net cost of transmission infrastructure (construction, maintenance etc.) and system operating costs (constraints, losses). In the subsections below, each approach is described and the relative merits of each option are compared.

7.1 Cost benefit analysis

CBA involves detailed analysis to identify the transmission infrastructure and system operation costs associated with different reinforcement options or boundary capabilities.

The more volatile and therefore more complex of these two costs to evaluate is clearly the system operating cost, since it is a function of many subjective factors and needs to be evaluated over the course of a whole year and also over the future lifetime of the asset. Factors include (in generally decreasing order of significance):

- Generator merit order
- Generator availability (within year maintenance and breakdowns as well as future new entrants and closures)
- Generator operating characteristics
- Generator bid and offer prices, which can and do change ½ hourly
- Wind availability and correlation at different locations
- Variation in network capability with seasons and outages, and outage likelihood/durations
- A year-round demand profile

The analysis process needs to be probabilistic in nature (Monte-Carlo simulation was used to produce the findings presented in this report), and tends to produce results that are sensitive to variations in the input assumptions.

Consultation Question: *CBA can include assessment of a number of factors. In its analysis the group has included some and excluded others. Questions 2 and 3 in section 11 seek industry views on the factors that it has taken into account.*

Transmission infrastructure costs can either be estimated for specific reinforcement options, or represented as a typical cost per MW of transfer capability. The implementation of each approach is described in the subsections below.

7.1.1 Specific reinforcement cost benefit analysis

In a specific reinforcement cost-benefit analysis, specific options for transmission reinforcement are identified, analysed and costed, and they are compared against each other, and against the default option of 'Do Nothing' which continues with the current transmission system. The year-round operating costs against each transmission option are studied for a number of future years, and against a number of future scenarios of generation and demand backgrounds over the anticipated 40yr lifetime of the investment. The capital costs of each reinforcement option are compared against the present-valued summation of savings in constraints and losses over future years, possibly out to the lifetime of the transmission assets. Broadly, the net cheapest reinforcement option is selected to proceed.

7.1.2 Indicative transmission price cost benefit analysis

This method uses generic transmission costs for each boundary, allowing a required capability to be identified. The method used to establish this capability for a boundary is as follows:

1. Firstly, an operating cost versus boundary capability curve is derived.
2. Secondly, a transmission cost versus boundary capability curve is plotted.
3. Finally, a curve of the overall cost of transmission and operation is plotted and the minimum found – this gives the optimum reinforcement level

A generic cost of reinforcement of is used in this approach. The nominal £100/MW.km price used in the working group's analysis is based on the costs of recent transmission developments although this will vary as time progresses and is likely to be influenced by increased off-shore development. A specific boundary “thickness” has been used for each boundary, to reflect the geographical variation in boundaries and their reinforcement. This gives a typical transmission cost line as below.

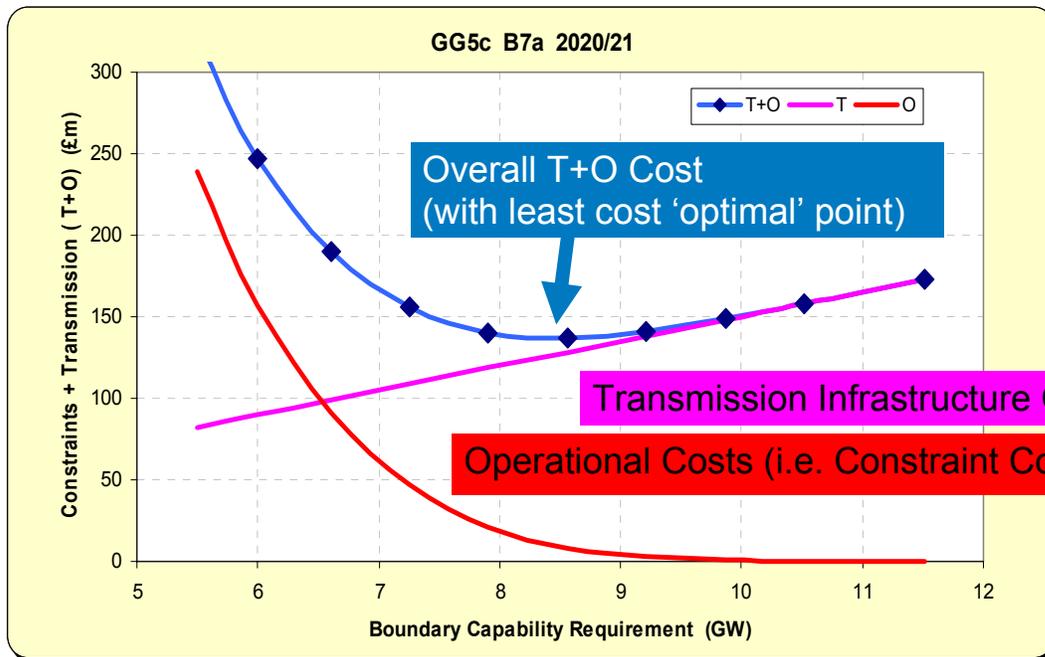


Figure 3 – Overall cost curve

To achieve robust boundary capability requirements, analysis of a number of scenarios at different time intervals is needed. Where a diverse range of requirements are identified, consideration of the probability of each scenario is needed and appropriate weightings given to each result.

7.2 Pseudo cost benefit approach

The goal of the pseudo CBA option is to address some of the practical concerns regarding the transparency, inconsistency and sensitivity of a CBA approach without reducing accuracy. The option achieves this by periodically conducting a Monte Carlo indicative transmission cost CBA in consultation with the industry, and mapping the result to a straightforward deterministic criterion.

In all cases a single generation / demand pattern is established. The manner in which it is formed varies between methods. In all of the approaches the capability is determined from the resulting planned transfer plus an allowance: this allowance is the existing interconnection allowance in all except one approach.

In considering this methodology it was agreed that GSR001 approaches 1a (the current wind integration method) and 1b (different scaling in exporting and importing groups) should be considered further. Additionally, the working group looked at variations of 1b which used different availability factors for wind generation throughout Great Britain (approaches 1b2, 1b3, 1b4), and a variation in which the availability factor varied by boundary (approach 1d).

Methods 1a, 1b and 1d all utilise a ranking order process to identify the generation included in the planned transfer condition. Given concerns regarding the ranking process, the working group conceived a new form of criterion that does not utilise a ranking order, but instead classifies the behaviour of generators entirely by their fuel type. Two method variants, 1c, utilising the existing interconnection allowance method, and 1e, in which a fixed boundary allowance is applied, have been assessed. Various different scaling factors were assessed for each generation class (approaches 1c1, 1c2, 1c3, 1c4).

The composition of these approaches are summarised in the table below. They are described more fully in Appendix 5.

	1a	1b1	1b2	1b3	1b4	1c1	1c2	1c3	1c4	1d	1e
Determine 'Non-Contributory' (Excluded) Plant by excluding generation that exceeds 120% of peak demand, when dispatched in order of their rank at the capacity shown below:											
Intermittent Generation	40%	40%	40%	40%	40%	N/A	N/A	N/A	N/A	40%	N/A
Other Generation	100%	100%	100%	100%	100%					100%	
Dispatch Remaining (Non-Excluded) Generation by setting its output to the values shown below (as % of their registered capacity), and then uniformly scaling all of the generation marked with a * so that the total level of generation matches peak demand. Generation not marked with an * should not be scaled during this step.											
Intermittent on importing side of boundary	72%*	5%*	15%*	25%*	35%*	72%*	72%*	60%	70%	<i>B1&15:</i> 90%* <i>B4&6:</i> 80%* <i>B7a:</i> 70%* <i>B8&9:</i> 60%*	70%
Intermittent on exporting side of boundary		72%*	72%*	72%*	72%*						
Nuclear	100%*	100%*	100%*	100%*	100%*	100%*	83%	83%	85%	100%*	85%
Interconnectors	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Hydro & Pumped	100%*	100%*	100%*	100%*	100%*	100%*	50%	50%	100%*	100%*	100%*
Peaking (MGT & Oil)	100%*	100%*	100%*	100%*	100%*	0%	0%	0%	0%	100%*	0%
Other Types	100%*	100%*	100%*	100%*	100%*	100%*	100%*	100%*	100%*	100%*	100%*
Then, add a boundary allowance to the observed flow across each boundary, to determine the required transfer.											
Boundary Allowance Calculation	Existing SQSS process, which uses 'the circle diagram' to determine an interconnection allowance for each boundary which is a function of the volume of generation and demand behind the boundary.										Allowance that ramps up to 1GW

Table 6 – Pseudo Cost Benefit Approaches

7.3 Merits of each option

7.3.1 Cost benefit analysis - both specific reinforcement & indicative transmission price variants

In principle a cost benefit approach would lead to the optimum development of transmission as it directly reflects the underlying economics. When a new transmission development is proposed the input assumptions can be identified for the lifetime of the investment and debated, leading to the conclusion that the investment proposal is robust against all reasonable assumptions for the future.

In practice, CBA requires a large number of input parameters, including:

- Conventional generation availability (within year, as well as future generation entrants and generation closures)
- Wind generation availability
- Year round merit order
- Seasonal transmission capabilities
- Transmission outage rates
- Bid and Offer price
- The cost of transmission infrastructure
- Availability and price of post fault measures, for example intertrips

Any results are very sensitive to variations in these input variables.

Forecasting these parameters for a few months into the future is difficult. Forecasting them for years into the future, where demand changes (electrification of Heat and Transport) as well as generation openings and closures (installed capacity forecast to rise from 82.5GW to over 110GW, with 13.7GW of generation closures in just the next few years) are anticipated, with any accuracy is extremely challenging. Consequently results derived from them will carry significant uncertainty. Credible variations in these input values can lead to significant differences in analysis results. Analysis of these sensitivities is reported in section 8.1. It is also likely that the best view of the forecast inputs will change regularly as new market information becomes available, for example the announcement of power station closures, applications for new power stations, and variations in fuel prices. This will lead to inconsistency in the optimal level of capability identified, adding to the uncertainty of transmission planning at a time when the provision of insufficient transmission capacity would lead to significant constraint costs and may even hinder the ability to meet the Government's environmental targets.

In the view of the working group, the 'accuracy' of the cost-benefit approach will be lost in the sensitivity to changes in the behaviour of generation. There seems little benefit in seeking the precision of this approach when the accuracy is limited.

It is acknowledged that the problem of variability and uncertainty in the background factors are faced by all industry participants, and that this does not by itself justify 'special treatment'. However, the working group believes that there are further significant difficulties specific to a CBA approach:

- One of the aims of an industry standard such as the NETS SQSS is to establish a transparent and consistent process (in this case, planning development of the transmission network), such that all industry participants can rely upon a standard level of performance and anticipate the implications of external developments (e.g. how much the transmission network will be expanded to facilitate the connection of a new generator). This is not possible with a CBA approach.
- In undertaking cost benefit analysis the TOs will be required to make assumptions on the input data. Some of these postulations may have commercial impacts on specific generators and the market in general, if made public. Consequently any such supposition will need to remain confidential to the TOs. This lack of visibility will mean that the planning process will not be replicable outside the TOs and will reduce the transparency of the procedure.
- At present the Scottish TOs do not have access to GBSO commercial data, which is the foundation of forecast data, and are prevented from using it by the conditions of the SO/TO code. If the Scottish TOs are to meet their licence obligations they would need access to this data to undertake cost benefit analysis of planned changes to their networks.
- Such an approach does not define an appropriate level of transmission capacity. Any applications for consent to develop transmission will have to be justified by demonstrating cost-optimality (which could be difficult if there is disagreement about input data assumptions). This is likely to add additional delay and uncertainty to the infrastructure development process.

It is the view of the working group that the practical difficulties associated with using a full CBA approach will need to be addressed before this approach could be adopted for transmission planning. In particular it will be necessary to:

- Establish a means by which future input data values are set
- Agree the level of industry involvement in setting these values, and their visibility to the Scottish TOs and the wider industry
- Agree the frequency of review for the input data

Resolution of these issues is likely to impact in a number of areas, for example a mechanism may be developed in which transmission charges are in part based on the degree to which a user provides data and user commitment, and consequently reduces uncertainty and risk.

Addressing these concerns will be of benefit in developing robust, consistent, agreed solutions, with some visibility of the process. However, the method will still be

complex and the results are still likely to be inaccurate: it is unlikely that any forecasting of future inputs will be accurate, although greater input from generators is likely to improve confidence.

Consultation Question: *The group has identified a number of issues associated with a CBA approach and highlighted those it feels need to be addressed by the industry if such an approach is to be considered further. Questions 4, 5 and 6 in section 11 relate to these issues*

7.3.1.1 Additional considerations regarding specific reinforcement CBA

An additional difficulty associated with the specific-reinforcement CBA process is that the nature of the approach presents difficulties in identifying when reinforcements are needed. Regular analysis assessing a number of possible development options against a “do-nothing” scenario is required to indicate that reinforcement is necessary. In this approach there is no clear concept of compliance as there is no defined desirable capability.

The working group believes that this issue significantly impacts on the usability of a specific-reinforcement CBA approach. The approach is better suited to assessing and selecting a specific reinforcement from a finite number of possible reinforcements once the need case for and approximate extent of reinforcement has already been established.

7.3.1.2 Additional considerations regarding indicative transmission price CBA

The main advantage of the indicative transmission price CBA option over the specific reinforcement approach is the ability to define and identify a minimum transmission capability.

Conversely, the main disadvantage is the inaccuracy which is introduced when representing the cost of transmission by a constant indicative cost per MW.km. In practice, transmission costs vary substantially between reinforcements and according to boundaries. For example:

- In some cases increased thermal capabilities can be achieved by re-conductoring, in others new circuits are needed
- Different types of reinforcements are required depending on the limits on the existing capability – for example the limit may be because of voltage, thermal or stability considerations
- The “thickness” of the boundary can vary considerably – new circuits can range between a few km and 100km or more
- To establish a cost of transmission with any accuracy is an iterative process: the reinforcement option depends on the existing and required capabilities, and the required capabilities depend on the cost of transmission.

Weighing the pros and cons, the working group judge that there is benefit in assuming average transmission costs to allow a substantially simplified CBA to be used, providing the assumption does not introduce significant inaccuracies.

Sensitivity analysis, involving doubling and halving of the transmission cost, has been performed to assess the level of error that this simplification introduces. These sensitivity results are described in section 8.1.

7.3.2 Pseudo cost benefit analysis

The working group has sought a method that further addresses the concerns of the specific cost benefit approaches whilst maintaining a link to the underlying economics. In particular it has attempted to develop a method that:

- Gives similar results to those of the indicative transmission price CBA approach, and is always within the credible range of uncertainty around the cost benefit optimum
- Sets the input data for a defined period of time to minimise repeat debates, ensure consistency, and support the development of additional infrastructure where this is found to be required
- Avoids making forecasts about specific generation plant, thus allowing the input data/assumptions to be made generally available
- Is not complex and can be applied by parties outside the TOs

All of the approaches are essentially attempts to fit a deterministic criterion to a desired CBA outcome, and therefore only have validity if their results are acceptably close to the CBA optimum. The working group's view is that an approach is valid if it consistently identifies boundary requirements within the range of uncertainty associated with plausible variations in the inputs to a CBA method. To this end, each of the options has been benchmarked against the indicative transmission price CBA. The results of this benchmarking are described in section 8.2.

This benchmarking fixes the input data assumptions until it is repeated. Fixing the data does not address the difficulty of predicting it, but it does allow methods that do not explicitly use the data to be developed and made more widely available. For details regarding the CBA used as the benchmark, please refer to appendix 5.

8 Analysis results

Analysis has been undertaken to determine:

- The extent to which the CBA based approaches are sensitive to the input data
- Whether any of the pseudo-CBA approaches produce results within the CBA uncertainty

The results are described in detail in appendix 5, but are summarised in this section.

The analysis is based on six major transmission boundaries for two variants of National Grid's Gone Green scenario. The boundaries are a subset of those used in system planning but have been chosen as representative of the diversity seen across the system. These boundaries are shown on the map in appendix 6. Details of the Gone Green scenarios are available here:

<http://www.nationalgrid.com/NR/rdonlyres/9A4B4080-3344-4C6D-8A19-411A867682F2/26834/GoneGreenfor2021.pdf>

8.1 Sensitivity to inputs

Regions of uncertainty have been identified for the GG5c scenario for two of the boundaries (B6 and B8). They show the ranges over which the required boundary capability and total costs vary for credible variations in the input data.

For each boundary nine total curves have been derived, as described in 7.1.2. These curves represent three operating scenarios (O , O_{low} , O_{high}) and variations of $\pm 10\%$ in transmission costs around them. The variations to produce the scenarios are:

- For the central case the operating costs are based on input data reflecting our central forecast founded on five years of historic observations
- The high and low cases are set by varying a few of the most sensitive input data parameters, mainly to the maximum and minimum range of values observed over the last eight years.²
- Likewise, the range of +10% and -10% on transmission cost is set to the range the TOs actually apply and experience in making initial estimates of reinforcement costs.

Based on these curves, uncertainty regions can be defined. These uncertainty regions encompass the plausible range of total costs that will result from building transmission somewhere between the lowest and highest optima identified for the range of scenarios.

² More exactly, for B6 in 2020, the high case is set by entering: (i) Peterhead entered at a merit position to achieve 70% rather than 60% load factor; (ii) Scottish Wind modelled at 37% rather than 35% load factor; (iii) Offer prices average 120 not 100 £/MWh. Likewise, the low case is set by entering: (i) Peterhead entered at a merit position to achieve 40% rather than 60% load factor; (ii) Scottish Wind modelled at 32% rather than 35% load factor; (iii) Offer prices average 80 not 100 £/MWh. These values represent the maximum and minimum values observed over the last eight years (annual averages). Since we set this range only according to what we have observed recently, we probably under-estimate the true range of what we may observe for such data parameters in forecast years.

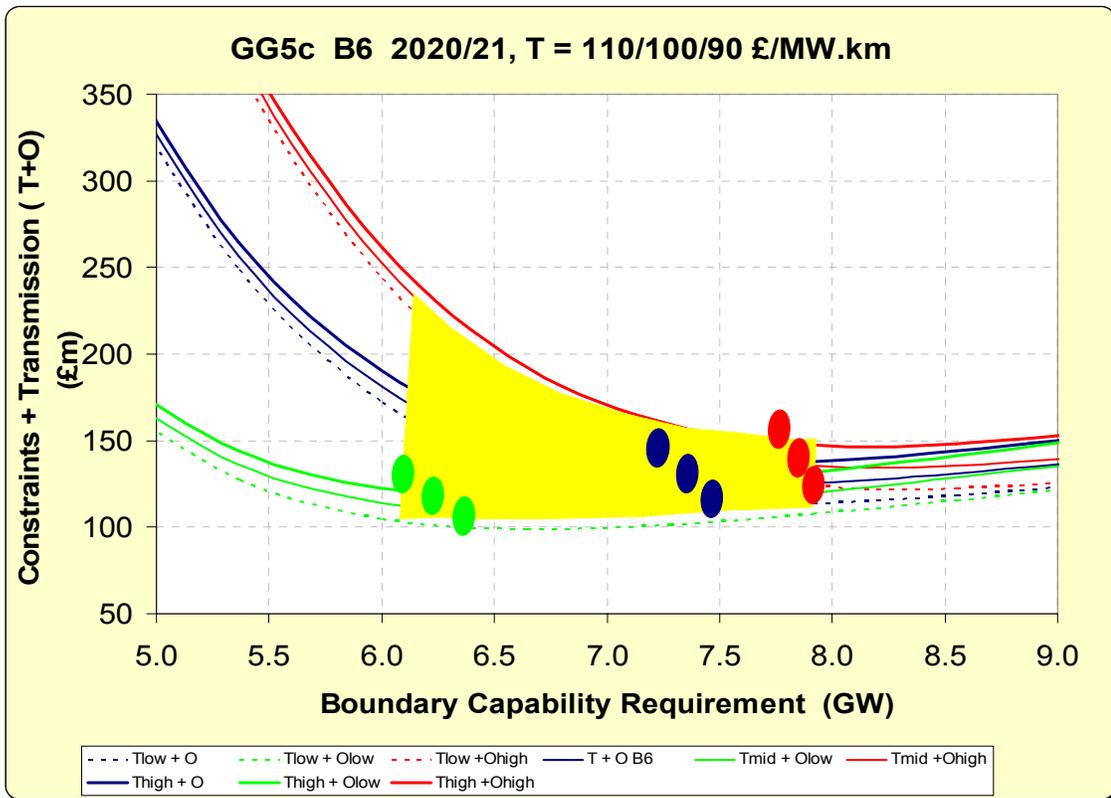


Figure 4 – Uncertainty Region for Boundary B6

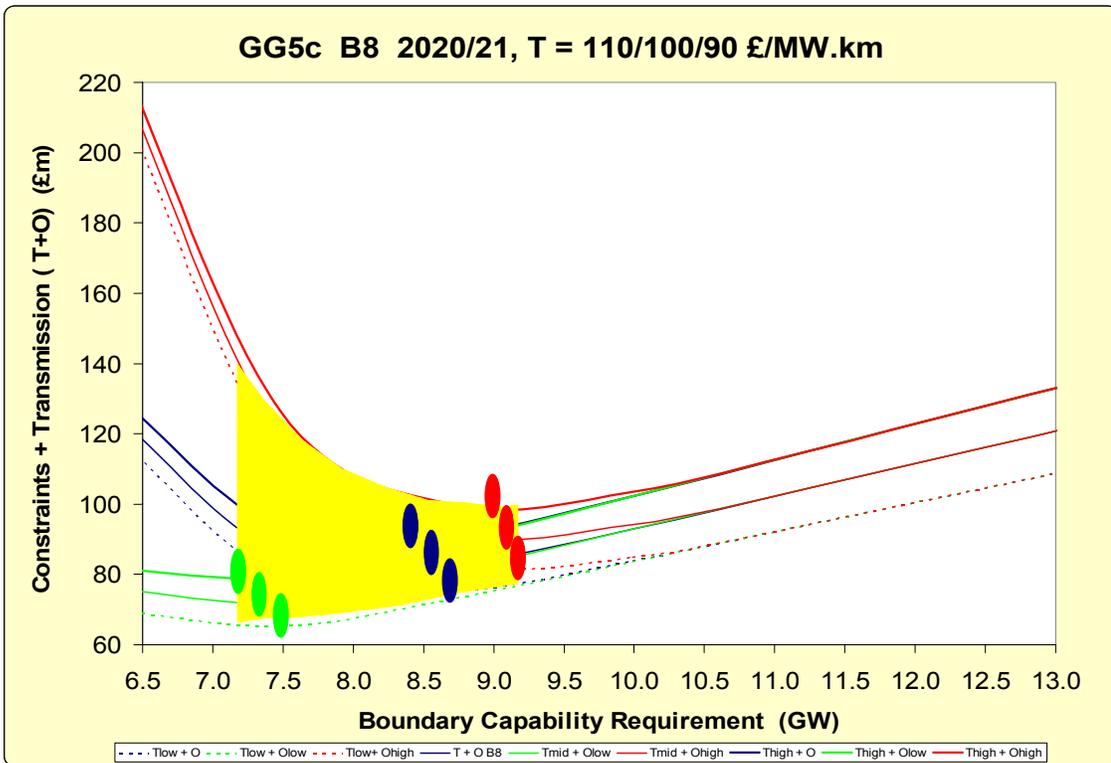


Figure 5 – Uncertainty Region for Boundary B8

The coloured circles on each curve show the minimum point of that curve, and hence the optimum level of transmission that would be identified for that scenario.

The results show that, within the uncertainty region, there are large capability and cost ranges.

Boundary	Minimum capacity GW	Cost range at min capacity (£m)	Maximum capacity GW	Cost range at max capacity (£m)
B6	6.2	100 - 240	7.9	110 - 150
B8	7.2	65-140	9.2	75-105

Table 7 – Uncertainty ranges

As the level of transmission increases it may in reality decrease or increase the total cost, depending on which of the input data cases is realised. However, as the level of transmission increases the potential for high constraint costs reduces at a greater rate than the rate of increase of transmission cost.

Further analysis has been performed for the central case. The tables below show, for each boundary:

- The optimum capability
- The total annual cost of building the capability and operating with it
- The range across which the total cost variation from the optimum is less than £5m per annum
- The capability identified by the current method
- The overall cost with the capability identified by the current method

Boundary	Optimum capability GW	Total Cost £m	Capability Range GW	Capability – current criteria GW	Cost current criteria £m
B4	4.1	44	3.6 – 4.8	2.8	96
B6	4.6	75	3.9 – 5.2	3.2	117
B7a	5.1	85	4.6 – 5.8	4.7	88
B8	7.3	76	6.8 – 8.5	8.7	82
B9	7.3	127	6.7 – 8.3	9.3	146
B15	8.4	53	7.7 – 9.5	6.7	113

Table 8 - Optimum boundary capabilities for GG5a scenario

Boundary	Optimum capability GW	Total Cost £m	Capability Range GW	Capability – current criteria GW	Cost – current criteria £m
B4	6.0	67	5.6 – 7.2	4.3	153
B6	8.0	129	7.3 – 8.8	5.8	218
B7a	8.4	137	7.8 – 9.2	7.3	156
B8	8.7	86	7.4 – 9.7	9.4	89
B9	7.3	127	6.7 – 8.3	9.3	146
B15	8.4	53	7.7 – 9.5	6.7	113

Table 9 - Optimum boundary capabilities for GG5c scenario

The sensitivity of the results to the cost of transmission is shown, for the GG5c scenario, in table10. The capabilities and total cost for each boundary with the central transmission cost assumption and transmission costs of twice and half this are given.

Boundary	Central assumption		High cost assumption		Low cost assumption	
	Capability GW	Cost £m	Capability GW	Cost £m	Capability GW	Cost £m
B4	6.0	67	5.8	130	6.2	35
B6	8.0	129	7.5	245	8.5	65
B7a	8.4	137	7.9	260	9.0	70
B8	7.7	86	7.6	160	9.0	45
B9	7.3	127	6.8	240	8.1	65
B15	8.4	53	8.1	110	8.8	30

Table 10 - Sensitivity to transmission cost

The results show that the fixed transmission cost CBA approach will in general require greater transmission capability than the current method. It will, however, result in a significantly lower overall total of transmission and operating costs.

The sensitivity results indicate that although the overall cost varies substantially with transmission cost, the optimum capability is reasonably consistent. The high cost assumption is always within 0.5 GW of the central case. The low cost assumption shows greater difference to the central case but the low cost curve is very flat around the minimum and there is little cost variation across a wide transmission capability range.

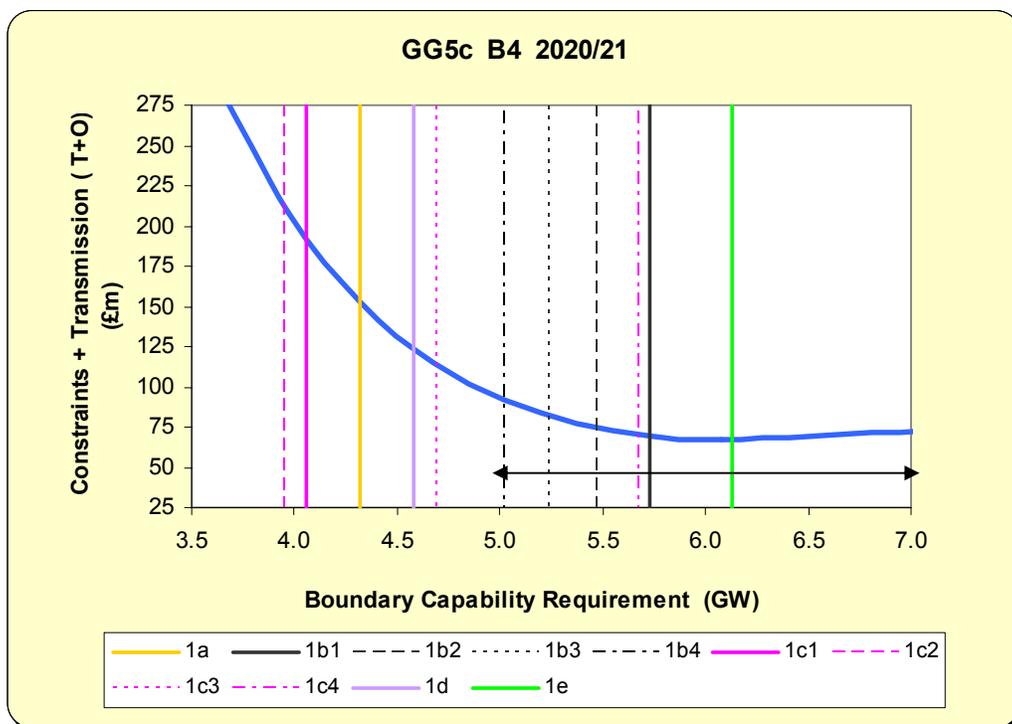
8.2 Alignment of pseudo cost benefit approach

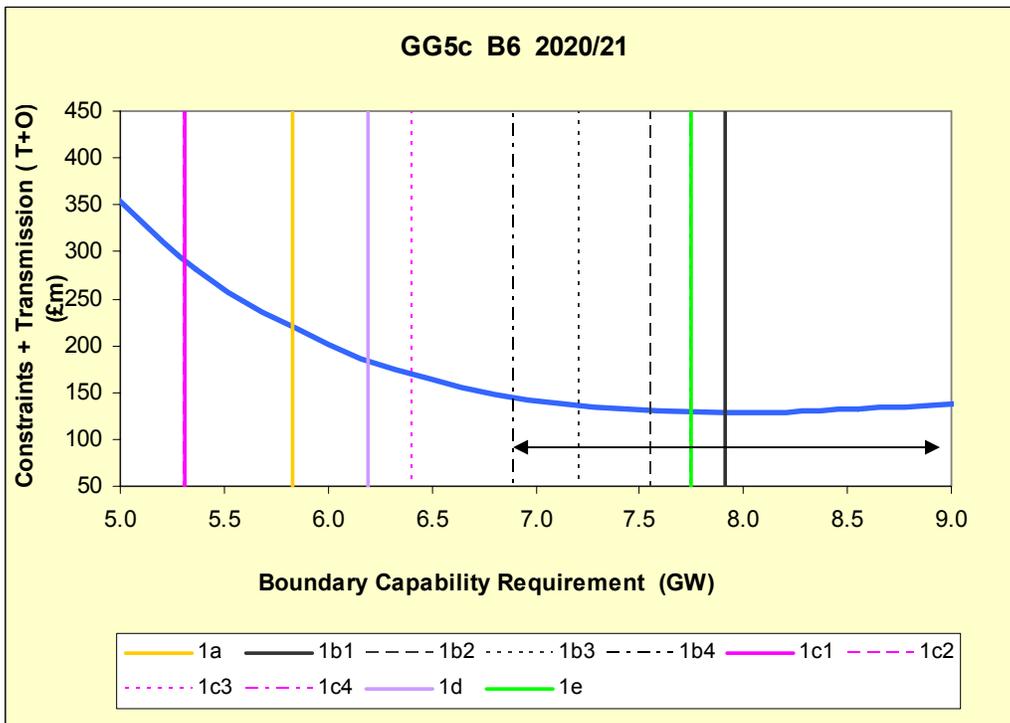
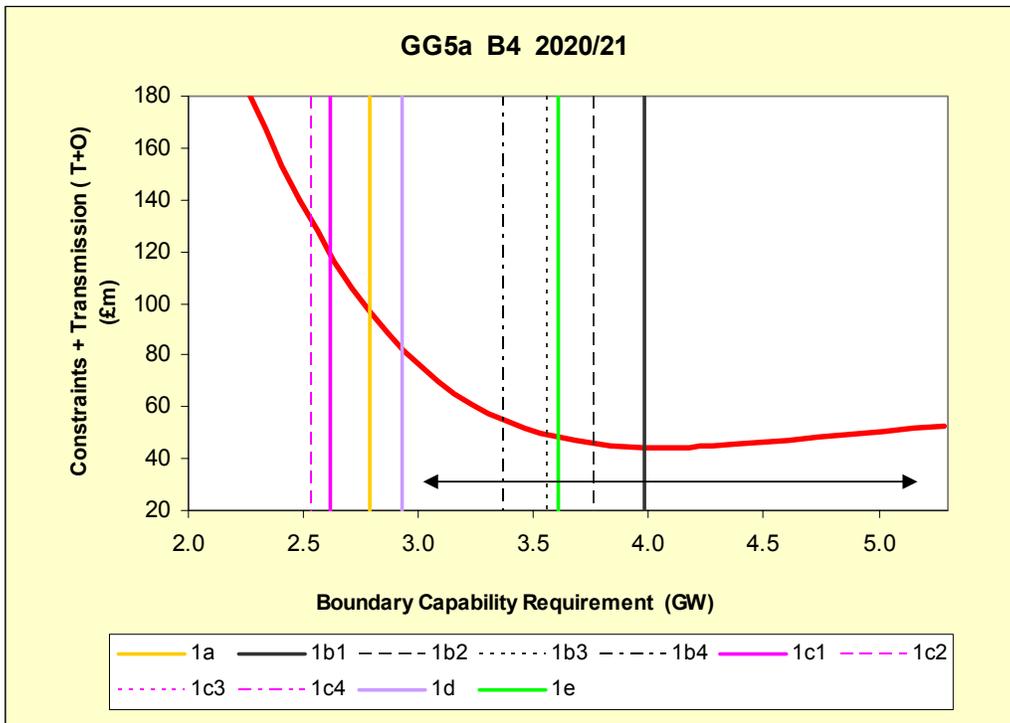
Each of the pseudo-CBA approaches has been benchmarked against the indicative transmission cost CBA to determine:

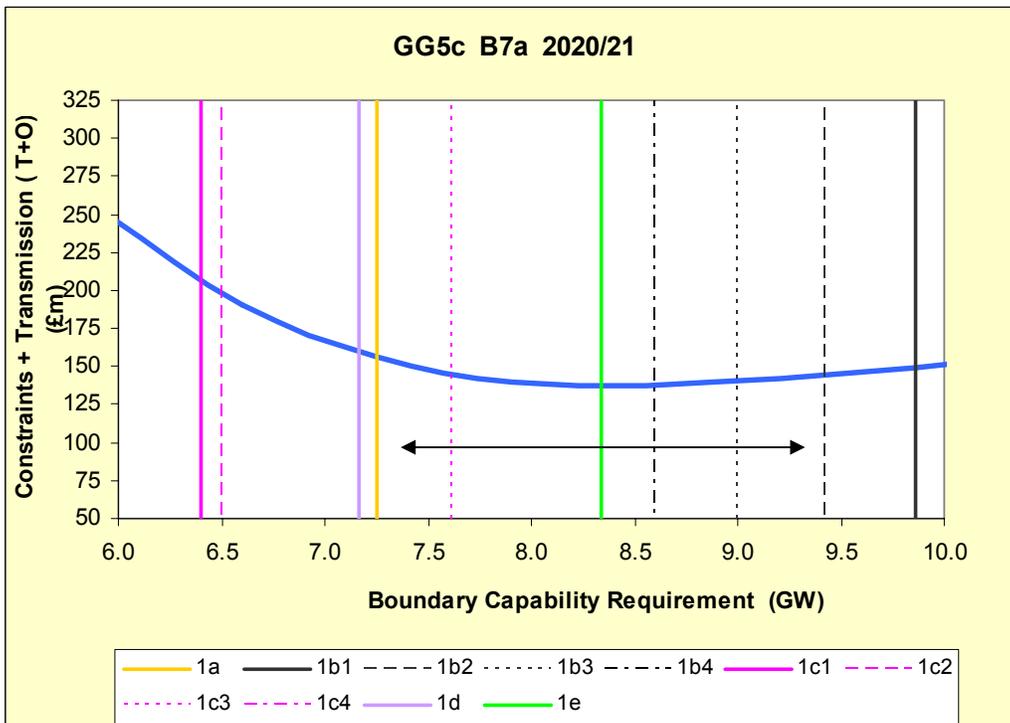
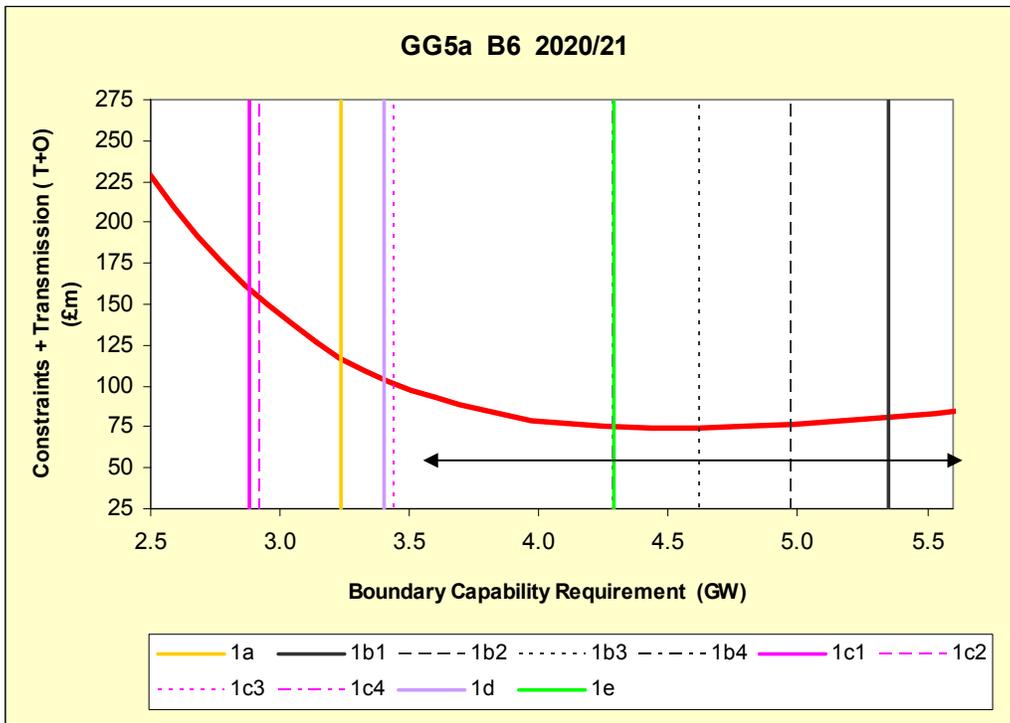
- whether it consistently falls within the uncertainty region
- its proximity to the central case optimum

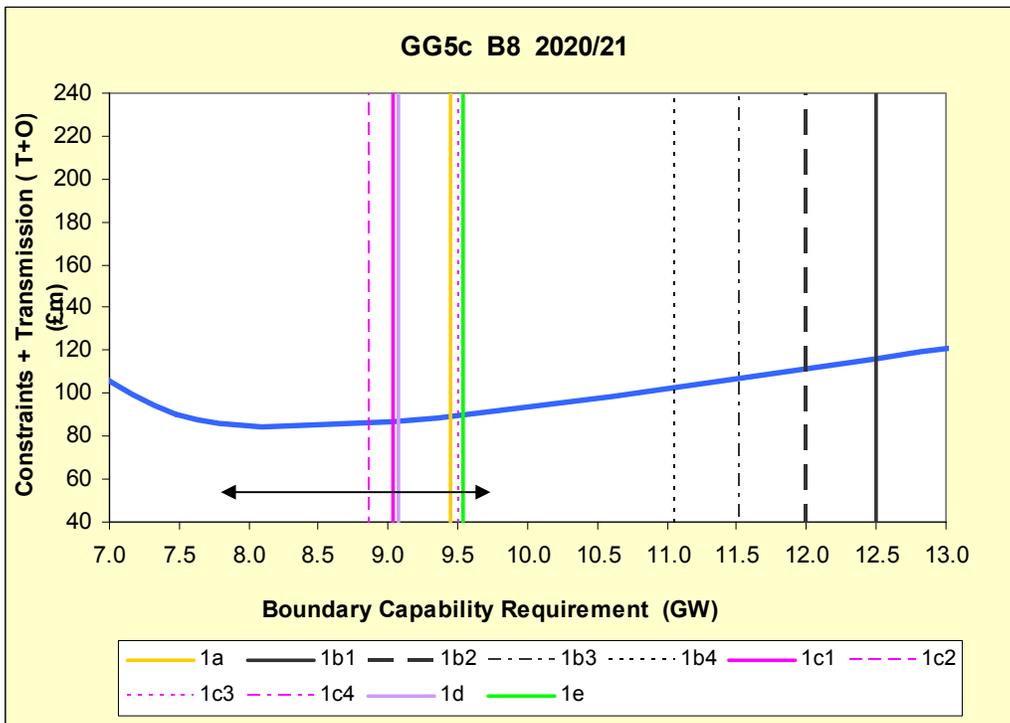
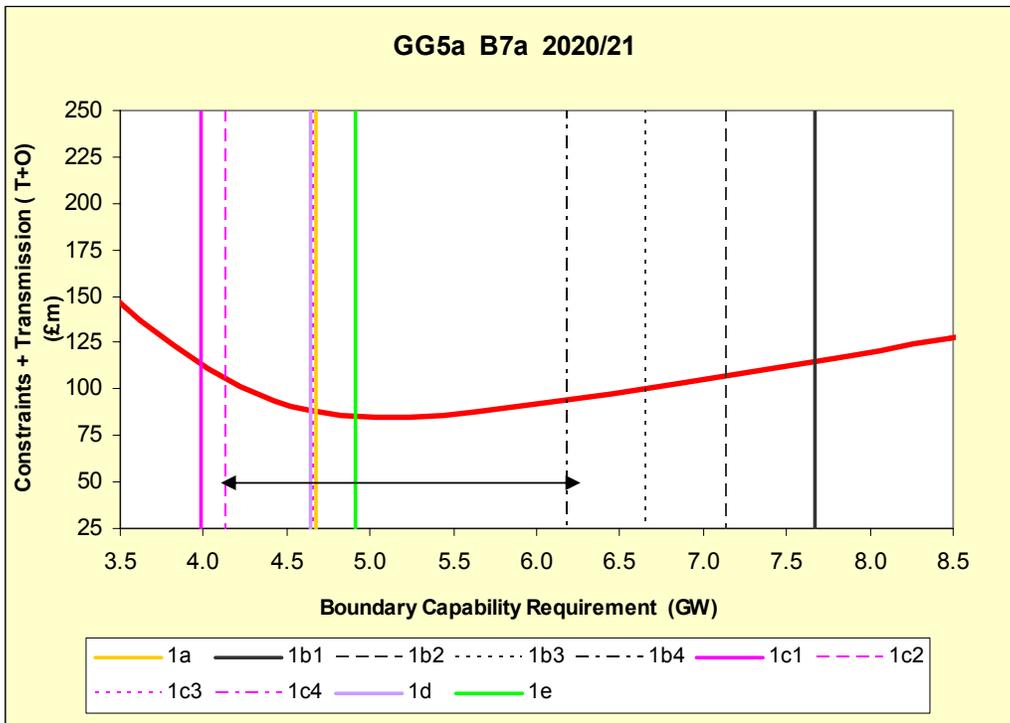
The sensitivity analysis described in section 8.1 for boundaries B6 and B8 suggest that, in general, the uncertainty range could be up to 1GW either side of the central case optimum. In comparing each option against the benchmark, a generic uncertainty range of ± 1 GW has been used.

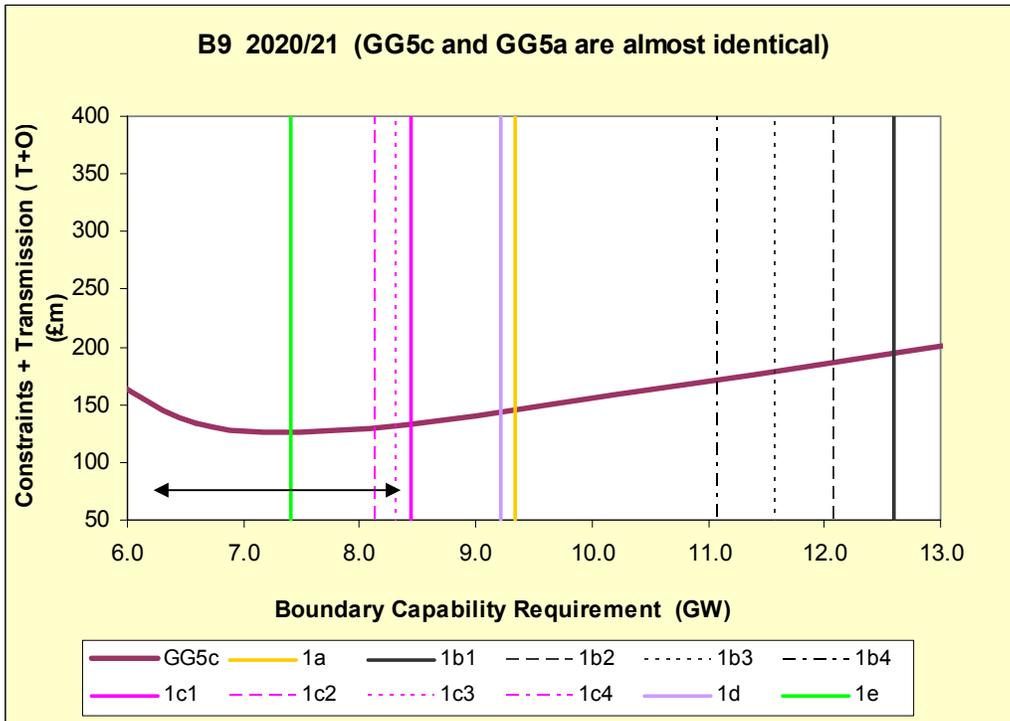
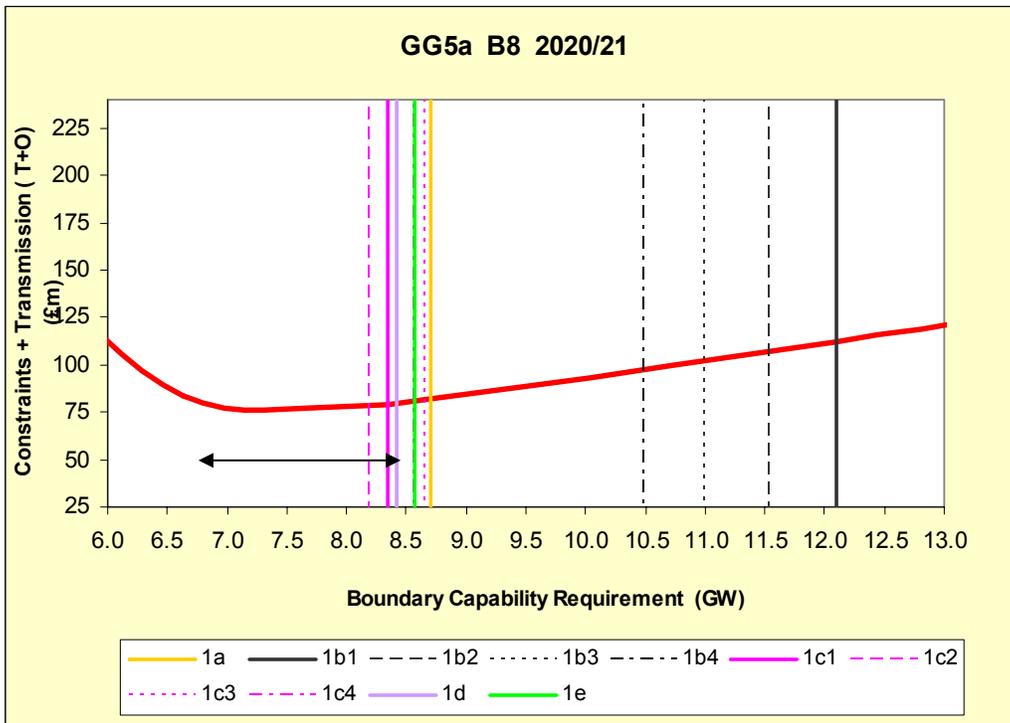
The following charts show the comparison of each option with the uncertainty region. Each chart shows the results of the comparison for one boundary in one scenario, as shown in the chart title (GG5a and GG5c are two variants of the Gone Green scenario). The curve is the total cost curve for the central case benchmark. The arrows indicate the uncertainty region around the minimum of this curve. The vertical lines are drawn at the capability identified by each method, as identified in the key. For example, the chart below is for boundary B4 in the GG5c scenario and indicates that method 1b4 identifies a capability requirement of 5GW, and that this just falls within the uncertainty region.

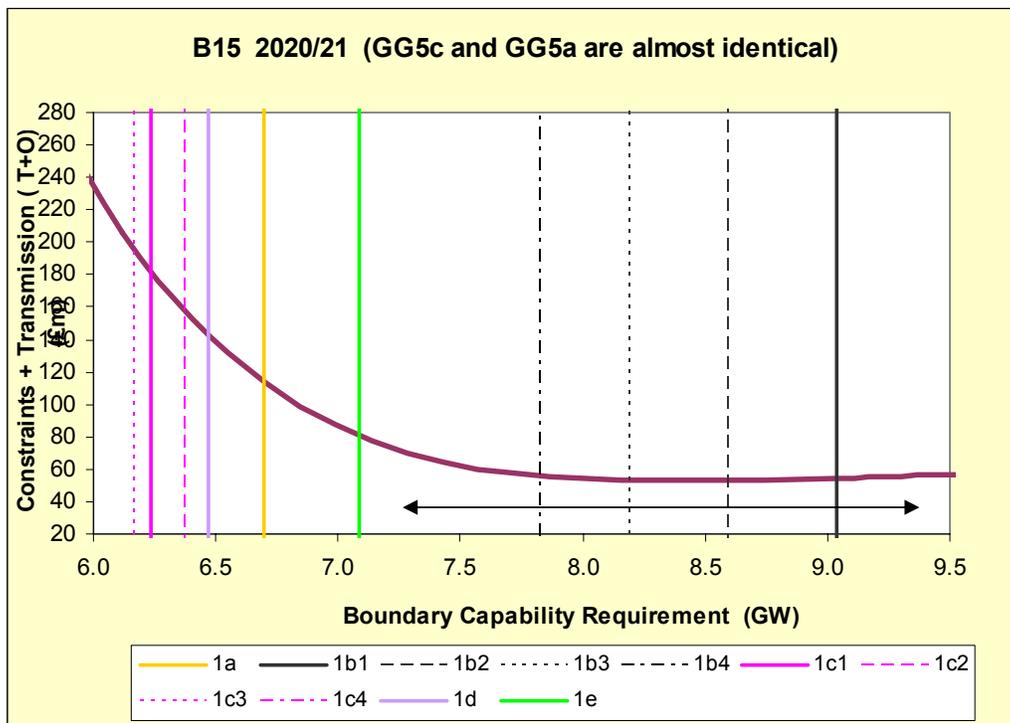












None of the methods consistently come very close to the central case optimum. To varying degrees all methods under-build for some boundaries and over-build for others. All options under-build for boundaries B4 and B6. In general methods 1b) overbuild for the other boundaries. 1a) and 1b) both under-build for B7a and B15 and over-build for B8 and B9.

The additional annual cost incurred by each approach compared with the central case benchmark – the regret - is shown in table 11. The costs in the table are, for each approach, the sum, across the six boundaries, of the differences between the benchmark boundary cost and the boundary cost associated with the approach.

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

Table 11 – regret for each option

Table 12 gives the total difference in network capability between each option and the benchmark. The capabilities in the table are, for each approach, the sum, across the six boundaries, of the differences between the benchmark boundary capability and the boundary capability associated with the approach.

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

Table 12 – capacity difference for each option

Methods 1e) shows the lowest regret and is very close overall to the benchmark capability requirement.

Method 1c4 shows relatively low regret but the capability requirement is much further from the benchmark than that in 1e.

All variants of option 1b tend to overbuild transmission, for boundaries B8 and B9 this is several GW. However, as the cost of overbuild is less per GW than the constraint cost associated with under-building, the cost impact is less severe than under-building and they show the next lowest cost regret.

The remaining options (1a, all other 1c variants and 1d) show greater cost regret.

The full results are shown in appendix 5. They are also shown in tabular form, with results colour coded according to their difference from the central case optimum.

8.3 Conclusions on each approach

8.3.1 Specific reinforcement CBA approach

The specific reinforcement CBA approach is, in principle, the best approach in terms of determining the correct level of transmission capability. It is a complex process and is not inherently transparent. In practice, the approach is likely to provide uncertainty and volatility in identifying transmission, to the extent that it is not likely to be more accurate than either of the simpler methods considered.

The working group's view is that the disadvantages of this approach significantly outweigh the advantages. The group does not see any merit in pursuing this approach unless mechanisms can be put in place to reduce the uncertainty of the input data.

8.3.2 Indicative transmission cost CBA approach

This approach has benefits compared with the specific reinforcement CBA approach:

- It is simpler to implement
- It identifies a level of required capability

However, the option does have an additional disadvantage in that the transmission costs used are not as accurate.

As with the specific reinforcement CBA approach, this approach is highly sensitive to a number of input parameters, and does not address the desire to develop a method that can be applied across the industry as its input data includes commercially confidential data and forecasts for individual power stations.

The working group believes that this method is preferable to the specific reinforcement CBA approach but considers that, as with specific reinforcement CBA, without a mechanism to better predict future scenarios the accuracy of any results will be limited. When combined with the lack of transparency, the group does not recommend this approach.

8.3.3 Pseudo cost benefit approach

All of the pseudo CBA options can be implemented relatively simply. As the underlying input data is fixed in the benchmark analysis, the results of any method will be consistent across the time between benchmarking exercises. As the methods do not require knowledge of the underlying cost benefit data, they can be replicated by any parties. They identify a level against which compliance can be tested.

Analysis has shown that over-building transmission is generally more economic than under-building because:

- the gradient of the total cost curve is lower as it moves to the right (due to greater transmission costs) than when it moves to the left (due to greater constraint costs)
- at higher transmission levels the range of total cost uncertainty lessens

Although there is uncertainty around the forecast scenario, the central case CBA scenario is more probable than those that define the uncertainty range. In general, the central case scenario minimum is slightly towards the higher transmission build / lower cost uncertainty end of the uncertainty region. For these reasons the group's view is that the method that most often gets close to the central case minima, whilst consistently falling within the uncertainty region, is the best.

The results of the options considered are varied. None of them consistently finds the central case optimum capability and a number do not regularly fall within the range of uncertainty associated with cost benefit analysis.

However the group's view is that option 1e fulfils the above criteria. This method shows low cost and transmission capability differences in comparison with the benchmark CBA. Consequently the group's preferred approach is 1e.

Consultation Question: *Approach 1e involves specific recommendations in a number of areas, including scaling factors for intermittent and nuclear generation, and the introduction of a new boundary transfer allowance. Questions 7 to 10 in section 11 seek views on this method.*

9 Conclusions

The working group has sought to identify an appropriate set of criteria for inclusion in the NETS SQSS to ensure that, in developing the NETS, the Transmission Owners identify the appropriate level of transmission capability to:

- ensure transmission does not restrict generation in providing demand security
- facilitate the most economic overall supply of electricity.

Based on analysis of eight years worth of wind data the working group has concluded that wind generation is insufficiently reliable to contribute to demand security at all times. Consequently a set of criteria specifically aimed at the transmission required to ensure that transmission does not impact on demand security, in which the contribution of wind is set to a low level, is proposed.

The group believes that further transmission build requires economic justification and proposes that criteria to determine the required capability are included in the NETS SQSS. Three methods that could be the foundation of these criteria have been investigated:

- a specific cost benefit analysis approach
- an “indicative transmission cost” cost benefit analysis approach
- a deterministic method, that is periodically benchmarked against a cost benefit derived measuring stick, and therefore provides a pseudo cost benefit result

All of the options have strengths and weaknesses. They are all underpinned by cost benefit analysis that is very sensitive to the input data, primarily the future economic behaviour of generation. The variation in results is considerable for a credible range of input assumptions. It is the view of the working group that this variation has a far greater impact on the identified level of capability than any of the simplifications that have been considered. In the opinion of the group further work is needed by the whole industry to develop better mechanisms for determining and providing stability of this forecast data.

The specific cost CBA approach is considered to have further significant disadvantages in that:

- It is not transparent
- It is complex to undertake

- It does not provide a clear concept of compliance, requiring all possible options for reinforcements to differing levels to be analysed and compared

The indicative transmission cost CBA approach addresses the issue of identifying a compliant level of capability, and in so doing limits the need to consider (and cost) a large number of reinforcement options. However, it still requires the explicit use of economic data to generate constraint curves and therefore it will not be possible to make it available for use outside of the TOs, and the present SO/TO code rules prevent the use of this data by the Scottish TOs.

The deterministic options considered have shown considerable variety in their results. It is inevitable that if any of these options is adopted it will sometimes under-build and sometimes over-build transmission in comparison with the true economic optimum. However, the group believes that this will be true of any method based on forecast data. As long as the method used falls within the range of uncertainty associated with the input data it is reasonable to assume that it is valid. Options that consistently fall within the range of CBA uncertainty have been identified.

The group's analysis suggests that it is economically preferable to over-build than to under-build transmission due to the relative costs of constraints and transmission. The benefit comes from reducing the potential range of total costs, although the potential minimum total cost of transmission and constraints does increase with greater network development. In the group's view, the best of the deterministic options will:

- be based on the most probable future scenario
- be within the CBA uncertainty region
- build a level of transmission that reduces the total cost risk without incurring excess investment

The group considers that the option that most closely aligns with the central case CBA, which is based on best view forecasts and tends to build transmission slightly above the mid-point of the uncertainty region, will meet the criteria.

Approach 1e best achieves this. In this method:

- All generation except peaking plant is considered contributory
- Wind generation is scaled to 70%
- Nuclear generation is scaled to 85%
- Other generation scales to meet demand
- A boundary allowance is applied – this allowance ramps up from 0 to 1 GW as the total group generation and demand increases from 0 to 5 GW

The group is conscious of the difficulties associated with gaining consent for major transmission developments and is mindful that delays to transmission development may incur significant constraint costs. It therefore favours the introduction of a method more likely to expedite the process of developing required transmission

capability. On this basis, the group considers that employing a deterministic method that identifies capabilities based on the above criteria will be beneficial

Based on the merits of each of the three approaches, the group has concluded that a pseudo-cost benefit methodology, in which deterministic rules are applied, is the most appropriate option for introduction to the NETS SQSS. The specific rules of the procedure should be periodically validated, and adjusted if necessary, by comparison with a cost benefit derived measure. The group's preferred approach is that described as option 1e in this report.

The working group acknowledges that none of the approaches considered will consistently provide the right answer. The group is therefore seeking industry views in a number of areas and has included a list of consultation questions in section 11. Views on aspects other than those addressed by the questions will be welcomed.

10 Recommendations

The wind integration working group recommends that:

- A set of criteria are included in the NETS SQSS to specifically identify the transmission capability needed to ensure that transmission does not restrict generation from providing demand security. These criteria should specify that any contribution from wind generation is included at a low level: 5% capacity appears to be appropriate. Any capability identified by these criteria should not require further justification. This "security capability" is broadly similar to the existing transmission system capability.
- Separate criteria are included to determine the need for additional transmission development intended to facilitate an overall economic supply of electricity. These criteria should be deterministic in nature, but should be periodically reviewed against cost benefit analysis. It is recommended that this review should take place at five year intervals. The proposed method is that described as 1e, and summarised in section 9 above.
- Industry mechanisms to provide more accurate and stable forecasts of the economic data needed to undertake cost benefit analysis should be developed. The aim of these mechanisms will be to reduce uncertainty and risk and consideration should be given to options that reflect increased user commitment, and therefore background certainty, through Industry Codes and the commercial framework.

11 Consultation Questions

Dual Criteria

1. We are proposing a two-part criterion within Chapter 4 of the SQSS for each MITS boundary, namely a 'Demand Security' criterion and a 'Wind Integration' criterion.
 - a) Do you agree in principle with a 'Demand Security' criterion, of the form we have proposed?
 - b) Within the Demand Security criterion, do you favour treating Wind at 0% or at 5% of capacity, and why?
 - c) Within the Demand Security criterion, do you favour continuing to treat Interconnectors as at present (in particular, with the IFA cross-Channel Link assumed to be sending power from France to England); or do you favour treating all Interconnectors at float?
 - d) Do you have any other detailed observations to make within the Demand Security criterion?

Within the Cost-Benefit Approach

The following questions assume that we adopt a cost-benefit approach for the 'Wind Integration' criterion:

2. Our cost-benefit approach includes assessment of the following cost terms:
 - T – the capital cost of the reinforcement, including interest during construction;
 - O – the constraint costs assessed, present-valued;
 - OUT – constraint costs due to the outages required to construct and commission the reinforcement
 - L – costs of the transmission losses saved by the reinforcement, present-valued

Note that we do not include any assessment of X – reduction in Unsupplied Energy. This is implicitly covered by the Demand Security Criterion, and we do not expect X to feature (even if we attempted to assess it) for the exporting boundaries.

Also note that we do not explicitly assess a carbon impact. One academic study has concluded that ~ 86% of the 40year lifetime carbon impact of a GB overhead line lies in the transmission losses, and a price of Carbon is included in the power price of transmission losses. Only ~ 3% of the lifetime carbon impact lies within the manufacture of the steel in the towers and the concrete in the foundations. The remaining ~ 11% of the carbon impact lies in the current levels of SF6 leakage from the switchgear, but this value is being addressed in other incentives on each TO. Our constraint prices, which are based on energy prices, do contain forward prices of carbon.

Do you identify any other 'costs' that we ought to include in the cost-benefit assessment? If so, please describe, and indicate how you think we ought to assess and value such components.

3. One of many key data items for the cost-benefit approach, is the period of time over which to perform the cost-benefit, and the test discount rate to be applied (which amounts to one's approach to present-valuing future cash-flows). The TOs propose to study at most ten years out, because future generation scenarios are so uncertain beyond such a horizon. Nonetheless, we will value constraint savings for year 10 as applying equally for years 11-40 of a transmission asset's life. We will apply a test discount rate of 6.25%, in line with our allowed cost of capital, as reflected in our TNUoS charges.

Do you suggest any other lifetime or treatment of future costs? Do you suggest any other test discount rate? If so, why?

4. Our cost-benefit approach merely requires that one assesses all identified reinforcements for each boundary. It thus has no concept of a compliant boundary, only that no economic reinforcements are identified. How much of a problem do you think this is? Can you articulate any criterion, which might lead to a concept of compliance within the cost-benefit framework?
5. The cost-benefit approach is significantly sensitive to the cost-benefit data. The cost-benefit data includes: generation availability, wind availability, generation merit order, transmission outage assumptions, generation Bid and Offer prices, and transmission prices. We note that our forecast data is likely to be dominated by historic behaviours which we have observed in the past; it is difficult to forecast genuinely new behaviours, which may nevertheless be likely for the future. What processes do you propose to allay concerns on the cost-benefit data?
6. We believe that, in order for the TOs to be able to fulfil their Licence obligation to plan their system in accordance with the SQSS, the GBSO will have to release extensive cost-benefit data to all TOs. This data will include forecasts of: generation availability, wind availability, generation merit order, and generation Bid and Offer prices. This will need to be to at least station and seasonal granularity. In order to understand and calibrate such forecasts, we also believe the GBSO should release historic data at the same granularity. Note that TOs will shortly include Offshore TOs.

This requirement involves removing some confidentiality clauses in the SO-TO Code ('STC'). In particular, the concept of 'zone of influence', which currently controls data release, is completely inappropriate in a cost-benefit context; in a cost-benefit context, each TO needs to know the nature and parameters for replacement plant across the entire GB. This issue will have to be the subject of a detailed STC consultation, but at a high level, do you have any concerns at such a relaxation of STC confidentiality clauses? Do you suggest any extra processes to manage the issue?

Within the Pseudo Cost-Benefit Criterion

The following questions assume that we adopt a pseudo cost-benefit criterion, closer to the current deterministic approach:

7. We are minded, within the pseudo cost-benefit criterion, to apply a Direct Scaling Factor for wind of 70%. This is because this factor calibrates best, for the six boundaries studied, against our economic measuring stick. Do you agree with this factor of 70%? Do you have any particular comment on parameter values assumed within this 'measuring stick' calibration?
8. We are minded, within the pseudo cost-benefit criterion, to do away with the previous concept of applying a ranking order to a 120% plant margin. Instead, after discounting a small class of clearly peaking plant as non-contributory, and fixing nuclear at 85% and wind at 70%, all remaining plant is scaled uniformly. Do you agree with us, that this approach is more consistent and less variable, than the existing ranking order approach?

Do you support any extension to our proposed methodology, that might seek to differentiate between base-load and marginal classes of Gas-fired and Coal-fired generation?

9. We are minded, within the pseudo cost-benefit criterion, to revise the treatment of Interconnectors as follows: First, we publish from time-to-time (eg in each year's Seven Year Statement), whether we treat each Interconnector as: (i) generation-like ie importing into GB; (ii) floating; (iii) demand-like ie exporting out of GB. Second, the demand-like are treated as other demands on the system (in practice, this treatment is likely for Irish interconnectors, and will result in less transmission being built, because such demands offset exporting groups). However the generation-like Interconnectors are treated as other generation, and are scaled along with all remaining generation to meet demand. Do you agree with us, that this treatment is more appropriate than previous treatments of Interconnectors?
10. Our recommended approach 1e uses an alternative boundary allowance to the current Interconnection Allowance. This will apply an additional transfer requirement to boundaries B1 and B2 that is not currently applied because the size of group behind these boundaries is smaller than the 1500MW Interconnection allowance threshold. We would welcome your view on this proposal.

11. The recommended approach has been benchmarked against the central case CBA. It is recognised that it will be necessary to periodically repeat this benchmarking, against an updated CBA, to ensure that the approach continues to provide aligned results. The working group recommends that this review is undertaken at five year intervals, in line with the price review periods. Do you believe this review frequency to be suitable? If not, how often do you believe the review should be undertaken, and why?

12 How to Respond

We welcome your views, in particular on the questions stated in section 11, but also in general, on the most appropriate way to plan transmission for intermittent generation.

Feedback should be forwarded in writing to:

eni.sqss@uk.ngrid.com

or:

Mark Perry
Electricity Network Investment
National Grid House
Warwick Technology Park
Gallows Hill
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Please reply by 9th July 2010.

Appendices

Appendix 1 – Terms of Reference

SQSS review - Wind Generation Modelling Working Group Terms of reference

Objective

To determine and make proposals on an appropriate method for the inclusion of wind generation in SQSS (transmission planning standards).

Scope

The group will:

1. Establish the current SQSS requirements and TO practices relating to modelling wind generation
2. Identify any issues with the current requirements and practices
3. Consider previous work done in this area and any conclusions and recommendations made
4. If necessary, identify and consider, appraise and justify additional options

The group will not:

1. Make proposals relating to the deterministic nature of the system events currently considered within the SQSS
2. Consider the use of demand management in managing wind generation variability

Group membership

The group will comprise representatives of NGET, SP and SSE, and OFGEM as an observer. NGET will chair the group and provide a technical secretary. The group may invite representatives of external parties to provide support.

Deliverables and Timescales

The group will present recommendations to the SQSS fundamental review panel by the end of May 2010. If approved, a public consultation on the recommendations will be issued in June 2010. A presentation on the consultation outcome will be made to OFGEM in July 2010.

Appendix 2 – Historical development of NETS SQSS

The transmission licensees are required to plan, operate and maintain the transmission system in an efficient and economical manner and to facilitate competition in the electricity market. Compliance with the SQSS is an electricity transmission licence requirement (NGET's standard condition C17, SPT and SHETL's standard condition D3).

The NETS SQSS has its roots in the 1940s and has evolved from a suite of six individual standards which concerned: the design of generation connections (PLM-SP-1); the design of the supergrid transmission network (PLM-SP-2); criteria for system transient stability studies (PLM-ST-4); voltage criteria for the design of the 400kV and 275kV supergrid system (PLM-ST-9); the design of demand connections (ER P2/5); and the operational standards of security of supply (OM3).

At vesting in March 1990, these standards were inherited by National Grid and were lodged with the then Office of Electricity Regulation (Offer, subsequently Ofgem) in accordance with Condition 12 of National Grid's transmission Licence and became commonly known and referred to as the Licence Standards.

The standards were written as separate, relatively independent, guidance notes for engineers. Their use by National Grid identified a number of areas of ambiguity and inconsistency both within and between the standards. A Review of Security Standards (RSS) was initiated by National Grid following a formal request by Offer (now Ofgem) in 1992. In 1996, following the conclusion of the review, Offer requested National Grid to update the standards and, in so doing, maintain the principles of the original Licence Standards except as modified by the RSS (e.g. in respect of customer choice and the greater use of operational flexibility). In meeting Offer's request, National Grid took the opportunity to combine all the standards into a single document referred to as the NGC System Security and Quality of Supply Standard (NGC SQSS). The previous six standards ceased to have effect in England and Wales from November 2000 when the new GB SQSS came into force.

However, in Scotland the transmission licensees had a different set of transmission planning and operational standards such as NSP 366, OM3 and GCI B1 and these were not part of the RSS undertaken by National Grid. Consequently, the Scottish transmission licensees continued to apply these standards. In 2003, in preparation for the introduction of the British Electricity Trading and Transmission Arrangements (BETTA), Ofgem requested that National Grid (as GBSO designate) and the three GB transmission owners (i.e. NGC, SHETL and SPT) harmonise the standards, as far as practical, while still retaining the principles of the NGC SQSS and without altering the underlying security of the system or incurring significant infrastructure expenditure. With the introduction of BETTA on 1st April 2005 the new standard, referred to as the Great Britain Security and Quality of Supply Standard (GB SQSS), replaced the previous standards used by the three GB transmission owners (including the NGC SQSS).

More recently, Ofgem and the Department for Business and Regulatory Reform (BERR) have been working together to implement a regulatory regime for offshore transmission systems. As part of this work, Ofgem requested that the TOs extend the GB SQSS to include offshore transmission systems as well as the onshore transmission system. New criteria for offshore networks were developed on the basis of a series of cost benefit analyses, bounded by pragmatic assumptions regarding the scale and distance of the generation from shore and the technology available at the time the analyses were carried out. These assumptions were suitable for Round 1 and Round 2 offshore developments but not Round 3 developments. The final change proposals were submitted to Ofgem in April 2008. Following Ofgem's consultation process, these changes were incorporated into version 2.0 of the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) and published on 24 June, 2009.

The current version of the NETS SQSS is available online at:

www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/

Appendix 3 – SQSS methodology without intermittent generation

The principles of the NETS SQSS are two fold:

- To ensure that the transmission system does not unduly limit demand security
- To economically facilitate competition in the generation market

The standard contains a number of chapters addressing specific issues in designing and operating the transmission system. Determination of the capability requirements of the main interconnected transmission system (MITS) is dealt with in chapter four.

Design of the Main Interconnected Transmission System

To achieve the above objectives a set of deterministic criteria are used to identify required transmission capabilities, with recognition that greater capability may in some cases be economically beneficial.

The criteria specify events against which the transmission system should be secured, meaning there should be no loss of demand or overloading of equipment.

Although the requirements of the standard are deterministic, they have an economic foundation. The events against which the transmission system should be secured are based on the probability of their occurrence. It is accepted that other, more severe events may happen, but it is considered uneconomic to develop a transmission system robust against all incidents. The standards therefore allow for the occasional loss of demand due to very rare events.

In analysing capability requirements a number of boundaries that split the transmission system into two parts are considered. The boundaries are set such that, in general, should any circuits crossing one of them be taken out, the flows on that circuit will be redistributed on other circuits crossing the same boundary. Any number of boundaries can be assessed but experience of the design and operation of the transmission system has honed in on those that are important to consider. Map showing these boundaries is included in appendix ?.

The primary driver of transmission reinforcement is the capacity required to meet peak demand. In assessing the capacity requirement a single scenario is analysed. In this analysis:

- Contributory plant to 120% peak demand is identified on the basis of that most likely to run
- This contributory plant is scaled to meet the demand (the scaling factor is 83%)
- The resultant flows across pre-defined boundaries are calculated – these are the planned transfers for the boundary

- An interconnection allowance is calculated for each boundary to allow for uncertainties in demand and generation
- The existing boundary capability is compared with the results of the analysis of:
 - Planned transfer + interconnection allowance versus boundary capability with any single circuit outage
 - Planned transfer + half the interconnection allowance versus boundary capability with any double circuit outage
- A reinforcement need is shown if either comparison indicates the boundary capability is insufficient

The criteria also require that the system is designed so that it can be economically operated all year round. System capability can be significantly reduced during maintenance and construction outages. In general the restrictions are most efficiently managed by operational methods, but the standard permits reinforcement where it can be shown to be more economic than operational alternatives or where operational measures cannot ensure demand security.

Appendix 4 – Previous GSR001 Review

Throughout 2007 a review of the SQSS for onshore intermittent generation was carried out by a working group under the direction of the SQSS Review Group (GSR001, GB SQSS Review for Onshore Intermittent Generation). This work led to a consultation document that was issued in January 2008. This report considered five options:

1. The current SQSS approach (option 1a) and a variant of this method, using variable A_T factors for wind generation (option 1b).
2. Security approach, considering the increase in Loss of Load Probability (LOLP) caused by limited transmission capacity.
3. “Membrane” security approach.
4. “Equal Access” approach, aiming to provide demand security and fair market access to generators. This work had not been fully completed when the GSR001 consultation was issued.
5. Pure economic approach.

It must be noted that options 1 – 4 were always to be backed up by a cost-benefit analysis, which could also be used to justify transmission capacity greater or less than the capacity prescribed by each approach. Unlike the pure economic approach, options 1 – 4 have the advantage of specifying a transmission capacity against which the compliance of the network can be assessed. If the costs do not justify actually constructing that network capacity, a derogation could be sought on that basis.

Option 1b was recommended by the GSR001 working group as it was considered transparent and relatively simple to apply, while providing an appropriate level of transmission capacity. By the end of February 2008, a number of responses to the GSR001 consultation were received. The responses can broadly be summarised as follows:

- The justification of the wind A_T factors in approaches 1a and 1b was considered weak or incorrect.
- There was support for approach 3 and, particularly for approach 4, as this method showed considerable promise at the time. Many respondents felt that the GSR001 consultation should have been delayed until work on approach 4 had been completed.
- There was relatively little support for a pure economic method and respondents were aware of the difficulty and complexity of this.
- There was support for proposals made by the Centre for Sustainable Electricity and Distributed Generation (SEDG) at around the same time. Although these were not part of GSR001, some of these proposals were subsequently taken forward in the Fundamental Review.
- Respondents also expressed support for the concept of “transmission sharing” and were concerned about the interaction with the Transmission Access Review that was ongoing at the time:

<http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx>

In early 2008, the GSR001 review was halted in favour of the Fundamental Review, which had a much broader remit and was to consider the treatment of wind generation more broadly and in more detail. Note that approach 1a, which was used before GSR001 started, remains in use by the transmission companies.

Appendix 5 – Full Deterministic Options Report

Introduction

This report contains a summary of the process and result of developing deterministic criteria to act as a pseudo cost benefit analysis by producing results that consistently align with the findings of a full probabilistic cost benefit analysis.

Also included in the report are approaches 1a and 1b from GSR001 as well as additional approaches that were developed as part of the review.

Assessment Structure

Overall

The assessment in this paper is a three part process, involving a winter peak model, a constraints model and a cost-benefit process. The peak and constraint models determine the constraint cost ('O'), and the transmission cost ('T') is calculated in the cost-benefit process. The minimum of 'T+O' plotted against boundary capability gives the optimum balance between transmission investment costs and constraints costs.

Winter Peak Model

This model calculates the required capability for a selected boundary, given forecast demand, a generation background and merit order, and Wind A_T factors for the Import and Export groups.

The detail of our Gone Green (GG) generation scenarios is held here. Included is a unique ranking number for each station, which ensures we allocate as 'Contributory' the most economic plant (eg. Wind/Wave) ahead of expensive plant (e.g. Pumped Storage). The Planned Transfer is evaluated by applying Wind A_T factors for the Import and Export groups (as defined by the choice of boundary), and finally we apply a global scaling factor to all generation to meet forecast demand.

Summing the Planned Transfer and the Interconnection Allowance (1/2 IA) gives the Required DC Thermal Capability for the selected boundary (Figure 9).

Constraints Model

This is effectively a two zone / one boundary version of the seven zone / six boundary annual Constraints forecasting model used in the GSR001 review (2008) and in the ENSG Report assessment of transmission system reinforcement options for 2020. The original model is described in the January 2008 *GRS001 Consultation, Appendix 5*.

The model uses a fuel-type merit order to determine the unconstrained generation schedule. The year is represented by three seasons and eight demand blocks of varying duration, and Monte Carlo simulation is used to model fuel-type availability.

The model determines the marginal fuel for each demand block, and then, if the unconstrained transfer is higher than the boundary capability, accepts the most attractive Bids to reduce plant running in the export zone. Correspondingly, the model accepts the cheapest Offers in the very large southern zone to balance demand. Model output is the constraint cost (the 'O' in 'T+O'), volume and price on the single boundary, whose required capability was derived earlier from the peak model.

Cost-benefit process

The transmission cost ('T') is calculated based upon the transmission price, the boundary thickness, and the GW required capability. Plotting T+O for several boundary capabilities produces the shape of the function, from which the optimum balance of T and O – the minimum of the function – can be determined.

SQSS Approaches

Using and extending the terminology of the GSR001 Consultation, this paper considers a number of deterministic approaches to handling Wind. These approaches all lie within the high-level deterministic approach of the current SQSS for MITS, namely simple scaling factors applied to classes of plant in exporting and importing groups, which determine the Planned Transfer for each boundary; thus these approaches are all variants of the high-level SQSS Approach One.

Figure 1 below summarises the details of each 'ranking order' SQSS approach, i.e. the percentages applied to Wind/Wave³ generation in the contributory / non-contributory derivation, and the A_T factors applied in Importing and Exporting groups. The individual approaches are then discussed in more detail. Figure 2 below gives an overview of SQSS new 'non-ranking order' approaches.

<i>Approach</i>	<i>Wind/Wave Contributory</i>	<i>Wind A_T Factor</i>	
		<i>Importing groups</i>	<i>Exporting groups</i>
1a	40%	72%	72%
1b1		5%	
1b2	40%	15%	72%
1b3		25%	
1b4		35%	

Figure 1: SQSS Approaches Summary

³ Since mid-2008, we have agreed that, since Wave and Tidal generation sources look to have an annual load factor of some 25-40%, it is sensible to treat Wave/Tidal identically to Wind, for the purposes of SQSS scaling. This decision appears robust, for penetrations of Wind/Tidal of up to 5GW. Accordingly, 'Wind' and 'Wind/Wave' are used interchangeably for the rest of this document.

Approach 1a

Scale all Wind across GB, in both exporting and importing groups, by 60%.⁴ This is consistent with the treatment of Conventional generation, which is scaled uniformly in both exporting and importing groups in all SQSS Approaches currently under consideration.

Approach 1b

Scale Wind on the exporting side of the boundary by 60% (in fact, use an A_T of 72%); and scale Wind on the importing side of the boundary, via an A_T of 5% 15% 25% or 35% (Approaches 1b1 1b2 1b3 and 1b4).

The GSR001 Consultation noted and accepted the consequence of Approach 1b, that one no longer has a single Planned Transfer condition for the whole of GB – there is a separate Planned Transfer condition of scaled generation for each boundary. This is because of the asymmetry in Wind A_T factors.

Approach 1c

These new approaches (1c1, 1c2, 1c3) are the variant of the ‘radical ranking’. In these approaches, obvious peak plants like OCGTs, fourth tranche Hydro, and half of Pumped Storage are declared as ‘non-contributory’. All other plants are ‘contributory’. All of these approaches abandon any residual concept of going down a ranking order to 120% plant margin.

Approach 1c4 is considerably different from 1c1-1c3 as it declares all Hydro and all Pumped Storage as ‘contributory’. In approach 1c4 Clean Coal is scaled identical to nuclear.

Approaches	A_T Factor					Direct Scaling Factor				
	Intercon.	Nuclear	Clean Coal	Renewable	Other (Non-Nuclear, Non-Renewable)	Intercon.	Nuclear	Clean Coal	Renewable	Other (Non-Nuclear, Non-Renewable)
1c1	N/A	100%	N/A	72%	100%	100%	N/A	N/A	N/A	N/A
1c2	N/A	N/A	N/A	72%	100%	100%	83%	N/A	N/A	N/A
1c3	N/A	N/A	N/A	N/A	100%	100%	83%	N/A	60%	N/A
1c4	N/A	N/A	N/A	N/A	N/A	100%	85%	85%	70%	N/A

⁴ Throughout this paper, the Reader is expected to understand that the loose language, such as ‘scale all Wind by 60%’, should be interpreted as in fact meaning: ‘apply an A_T factor of 72% to Wind capacity; and then apply the normal SQSS process of scaling generation to ACS demand by typically 83%, such that the final treatment of Wind within the Planned Transfer condition is at a scaling factor of $72\% \times 83\% = 60\%$ ’. (The expert will note that, in scenarios of high Wind penetration, the SQSS scaling factor turns out much less than 83%, say 73%, such that Wind ends scaled to nearer 50% than 60%)

Figure 2: SQSS Non-ranking order Approaches Summary

The advantages of 1c1-1c4 lie in a more robust ranking process, not in better economics.

- In 1c1, $A_T = 100\%$ is applied for non-renewable and $A_T = 72\%$ for renewable⁵. Planned Transfer is set by scaling all contributory plant thereafter.
- In 1c2, $A_T = 100\%$ is applied for non-nuclear and non-renewable and $A_T = 72\%$ is used for renewable. Planned Transfer is then set by:
 - Fixing the nuclear direct scaling factor = 83.3%
 - Then scaling all the remaining contributory plant thereafter⁶
- In 1c3, $A_T = 100\%$ is applied for non-renewable. Planned Transfer is set by:
 - Fixing the nuclear direct scaling factor = 83.3% and renewable direct scaling factor = 60%
 - Then scaling all remaining contributory plant thereafter
- In 1c4, Planned Transfer is set by:
 - Fixing the nuclear direct scaling factor = 85%, renewable direct scaling factor = 70% and clean coal direct scaling factor = 85%.
 - Then scaling all the remaining contributory plant thereafter

The 'Direct Scaling Factor (DSF)' is in fact the proportion of capacity to be netted off demand. Historically we have always netted 100% of interconnection capacity off demand, and in these approaches we are similarly netting off a proportion of nuclear/renewable capacity. This method takes the affected fuel type(s) out of the contributory calculation altogether as can be seen from Figure 2, one either applies an A_T factor or a DSF, never both.

Approach 1d

<i>Approach</i>	<i>Wind/Wave Contributory</i>	<i>Wind A_T Factor</i>	
		<i>Importing groups</i>	<i>Exporting groups</i>
1d - (B1, B15)		90%	90%
1d - (B4, B6)	40%	80%	80%
1d - (B7a)		70%	70%
1d - (B8, B9)		60%	60%

Figure 3: Proposed SQSS Ranking Order Approaches

⁵ For Approach 1c1, 1c2, 1c3; 'Renewable' = 'Wind + Marine (Tidal/ Wave)'

⁶ So the final scaling factor may well end up at 75% for Others (Non-Nuclear, Non-Renewable) and 54% for Renewable

This approach is similar to 1a. Wind/Wave Contributory factor is set to 40%, as in Approach 1a. Wind A_T factor for the import and export side of a given set of boundaries is constant and vary from other set of boundaries. Figure 3 gives an overview of how wind A_T factor varies between boundaries. Approach 1d is just a simple variable A_T method.

Approach 1e

This new approach 1e is also an alternative of the ‘radical ranking’ proposal and reasonably similar to approach 1c4. 1e stands out from other approaches by the use of an alternative boundary allowance to the standard interconnection allowance. The 1e boundary allowance increases linearly from 0MW to 1000MW as the total group generation plus demand rises to 5GW. For higher levels of generation and demand it remains at 1GW

Approaches	A_T Factor					Direct Scaling Factor				
	Intercon.	Nuclear	Clean Coal	Renewable	Other (Non-Nuclear, Non-Renewable)	Intercon.	Nuclear	Clean Coal	Renewable	Other (Non-Nuclear, Non-Renewable)
1e	N/A	N/A	N/A	N/A	N/A	100%	85%	85%	70%	N/A

Figure 3a: SQSS Non-ranking order Approaches Summary

In 1e, Planned Transfer is set by:

- Fixing the nuclear direct scaling factor = 85%, renewable direct scaling factor = 70% and clean coal direct scaling factor = 85%.
- Then scaling all the remaining contributory plant thereafter.
- Thereafter, a 'Boundary allowance' of up to 1000 MW is added to Planned Transfer, to determine boundary requirement.

Background Scenarios

This paper appraises possible SQSS methodologies against *Gone Green* background scenarios predominantly in 2020/21, but also in 2015/16 and 2030/31.

The three *Gone Green* backgrounds are as documented in the ENSG Report (July 2009); they differ only in the location of Wind, as illustrated below:

GG5c: this is the ‘*Final Gone Green 5 2030*’ scenario of 30th July 2008, as agreed between the TOs; this has 11.4GW of Scottish Wind generation in 2020.

GG5b: as GG5c, but with 8.0GW of Scottish Wind and +3.4GW of English Wind. (Shown for completeness only: we are not assessing SQSS methodologies against this)

GG5a: as GG5c, but with only 6.6GW of Scottish Wind and +4.8GW of English Wind.

Headline totals of Wind and Conventional generation in these scenarios are shown in Figure 4 below. Wave & Tidal has been split out from Wind, though it is modelled similarly, in order to highlight the differences between GG5c and GG5a, which, as we have said, are the allocations of wind between England & Wales and Scotland.

		GG5c						GG5a					
		2015/16		2020/21		2030/31		2015/16		2020/21		2030/31	
		imp	exp										
B4	Demand	60.0	1.6	59.2	1.6	57.9	1.5	60.0	1.6	59.2	1.6	57.9	1.5
	<i>Wave & Tidal</i>			0.9	0.5	2.9	1.5			0.9	0.5	2.9	1.5
	<i>Wind</i>	7.6	3.7	22.5	6.9	32.7	7.2	8.3	3.0	25.4	4.1	35.6	4.4
	<i>Conventional</i>	68.4	2.9	63.4	2.9	55.9	2.9	68.4	2.9	63.4	2.9	55.9	2.9
	<i>Interconnection</i>	2.5		2.0		3.5		2.5		2.0		3.5	
	Installed Capacity	78.4	6.7	88.8	10.4	95.0	11.7	79.2	5.9	91.6	7.5	97.8	8.8
B6	Demand	55.8	5.8	55.1	5.7	53.9	5.5	55.8	5.8	55.1	5.7	53.9	5.5
	<i>Wave & Tidal</i>			0.8	0.6	2.8	1.6			0.8	0.6	2.8	1.6
	<i>Wind</i>	4.4	6.9	18.0	11.4	27.0	12.9	5.8	5.5	22.8	6.6	31.8	8.1
	<i>Conventional</i>	63.0	8.3	59.0	7.3	52.8	6.1	63.0	8.3	59.0	7.3	52.8	6.1
	<i>Interconnection</i>	2.5		2.0		3.5		2.5		2.0		3.5	
	Installed Capacity	69.9	15.2	79.9	19.3	86.1	20.6	71.2	13.9	84.7	14.5	90.9	15.8
B7a	Demand	51.7	9.9	51.0	9.8	49.8	9.6	51.7	9.9	51.0	9.8	49.8	9.6
	<i>Wave & Tidal</i>			0.6	0.8	2.6	1.8			0.6	0.8	2.6	1.8
	<i>Wind</i>	3.4	7.9	15.8	13.7	24.3	15.7	4.8	6.5	20.6	8.9	29.1	10.9
	<i>Conventional</i>	56.1	15.2	53.6	12.7	49.1	9.7	56.1	15.2	53.6	12.7	49.1	9.7
	<i>Interconnection</i>	2.5		2.0		3.5		2.5		2.0		3.5	
	Installed Capacity	62.0	23.1	71.9	27.2	79.5	27.2	63.4	21.8	76.7	22.4	84.3	22.4
B8	Demand	39.7	21.9	39.2	21.6	38.3	21.1	39.7	21.9	39.2	21.6	38.3	21.1
	<i>Wave & Tidal</i>			0.6	0.8	2.6	1.8			0.6	0.8	2.6	1.8
	<i>Wind</i>	2.5	8.8	10.5	18.9	15.5	24.5	2.6	8.7	11.9	17.5	16.9	23.1
	<i>Conventional</i>	36.7	34.6	35.6	30.7	35.3	23.5	36.7	34.6	35.6	30.7	35.3	23.5
	<i>Interconnection</i>	2.5		2.0		3.5		2.5		2.0		3.5	
	Installed Capacity	41.7	43.4	48.7	50.4	56.9	49.8	41.8	43.3	50.1	49.0	58.3	48.4
B9	Demand	31.6	30.0	31.1	29.7	29.0	30.4	31.6	30.0	31.1	29.7	29.0	30.4
	<i>Wave & Tidal</i>			0.6	0.8	1.8	2.6			0.6	0.8	1.8	2.6
	<i>Wind</i>	2.5	8.8	9.0	20.4	27.7	12.3	2.5	8.8	9.0	20.4	27.7	12.3
	<i>Conventional</i>	25.2	46.1	25.7	40.6	28.2	30.6	25.2	46.1	25.7	40.6	28.2	30.6
	<i>Interconnection</i>	2.5		2.0		3.5		2.5		2.0		3.5	
	Installed Capacity	30.2	54.9	37.3	61.9	57.7	49.0	30.2	54.9	37.3	61.9	57.7	49.0
B15	Demand	58.7	2.9	57.9	2.9	56.6	2.8	58.7	2.9	57.9	2.9	56.6	2.8
	<i>Wave & Tidal</i>			1.4		4.4				1.4		4.4	
	<i>Wind</i>	10.2	1.1	27.5	2.0	38.0	2.0	10.2	1.1	27.5	2.0	38.0	2.0
	<i>Conventional</i>	63.4	7.9	57.8	8.4	49.4	9.4	63.4	7.9	57.8	8.4	49.4	9.4
	<i>Interconnection</i>		2.5		2.0	0.5	3.0		2.5		2.0	0.5	3.0
	Installed Capacity	73.6	11.5	86.7	12.4	92.3	14.4	73.6	11.5	86.7	12.4	92.3	14.4

Note: Imp and Exp "swap" for B9 in 2030/31 (for both GG5c and GG5a).

Figure 4: Demand and Installed Capacity by Background Scenario

It can be seen we are considering export groups of 5-50% of GB demand, where the exporting group contains 5-10GW of Wind in the smaller groups, up to 10-20GW in

the larger groups; and there is 10-20GW of Wind in the corresponding importing groups. This is a fair coverage of likely cases of 10-30% Wind penetration in GB up to 2020.

System Boundaries

This paper performs cost-benefit appraisals individually for just six GB system boundaries, namely:

B4 SHETL to SPT:

We have extended the original GSR001 consideration of boundaries to include this major within-Scotland boundary.

B6 SPT to NGET:

This boundary is also known as 'Cheviot'.

B7a NGET modified Upper North:

This is the Upper North B7 boundary, re-drawn South of Penwortham rather than South of Harker, in order to capture the export from Heysham and North-West Wind.

B8 North to Midlands:

Here the exporting group is much larger, containing 35% of GB demand (2020/21), rather than 16% for B7a and 9% for B6. The conventional generation is much greater, and the Wind in the importing group reduces from 15.8GW for GG5c 2020 to 10.5GW, now excluding the North-West and Dogger wind.

B9 Midlands to South:

Further demand and conventional generation are included in the exporting group; the balance of Wind between the exporting and importing groups is broadly the same as for B8.

B15 Thames Estuary:

On the export side of this boundary we have the French interconnection.

Cost-Benefit Data

Some of the important data assumptions, which feed into the cost-benefit, are discussed here.

Cost of Transmission Reinforcements (T)

Since we are performing a generic appraisal, we use a generic reinforcement price of 1000 £/MW.km capital. Annuitised over ten years, this equates to a price of 100 £/MW.km. pa. For 2020/21 only, we perform sensitivities in which the transmission price is halved and doubled (50 £/MW.km and 200 £/MW.km pa).

Actual reinforcement prices currently being considered for real within the ENSG project to appraise the *Gone Green* scenarios exceed even these prices. This is broadly because we do not believe that a third major overhead line route from Scotland would be feasible within *Gone Green* timescales, and hence we are exploring offshore DC cables options, which have greater unit prices.

The Transmission Reinforcement cost is defined as the product of reinforcement price, boundary thickness and required capability. (Boundary thicknesses are shown in Figure 5). Thus 3.3GW capability on B9 equates to a transmission cost of £51.2m (3.3GW x 155km x £100/MW.km).

We should note that we are assessing an *absolute* capability, rather than an *increase from a baseline* capability. In fact this does not matter, since our method only affects the absolute value of T quoted in 'T+O': it does not alter the relative comparison of approaches at all.

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

Figure 5: Boundary Thickness

Cost of Constraints (O)

The most important data item, apart from the generation backgrounds of the *Gone Green* scenarios and the boundary capabilities discussed below, is the generation prices, which have barely changed from the GSR001 consultation:

Fuel	Rank	£/MWh	
		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

Figure 6: Merit Order

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 reported below, the average Constraint price is 90 £/MWh, which follows directly from these Bid and Offer pricing assumptions.

Losses (L) and Construction Outage (OUT) Costs

We have discovered, during actual applications within the *Gone Green* appraisals, that the costs of L and OUT rarely exceed 10% of the major costs of T and O in these cost-benefits. Accordingly, given the wide range of sensitivities for T and O necessary within the ambit of this paper, costs of L and OUT are ignored throughout.

Transmission plus Constraints (T+O) Costs

Since we are ignoring losses and construction outage costs, our cost-benefit curve is defined as the sum of the (linear) transmission costs and the (approximately quadratic) constraints costs, as shown in Figure 7.

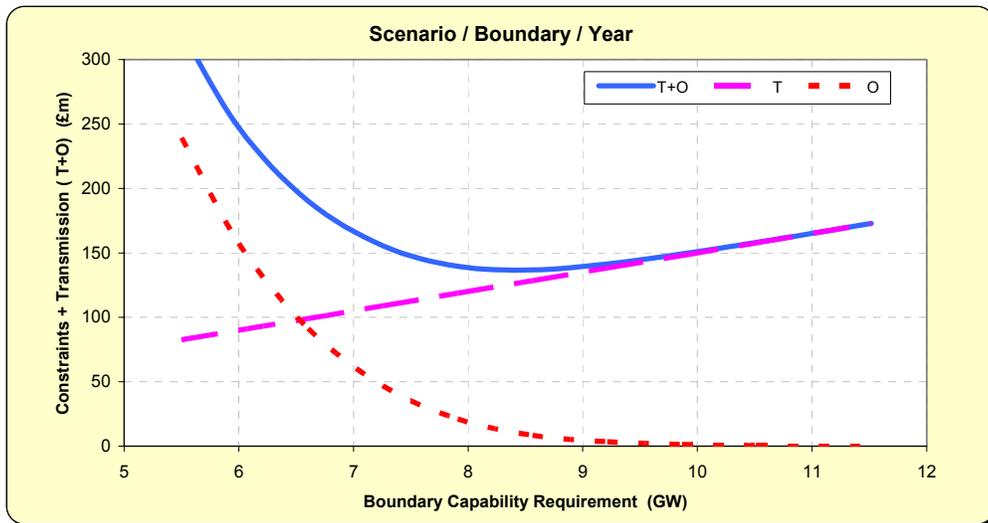


Figure 7: Transmission plus Constraints curve

The optimal MW capability point is the *minimum* of the T+O curve, and here this is some 8.5GW. 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.

This analysis has produced charts of this type for combinations of Scenario, Boundary and Year in order to assess the relative merits of each Approach. For each chart, we have highlighted the required capability for each Approach and, for 2020/21 only, ascertained the optimum capability and considered two transmission pricing sensitivities. For clarity of presentation, we show only the T+O curve and not the component cost curves.

Required Boundary Capabilities, by Approach

Applying the five SQSS approaches⁷ to our scenarios yields the required boundary capabilities shown in Figure 9. These are in fact the Winter capabilities: the Constraints model studies three seasons (Winter, Summer_Intact and Summer_Outage) and the capabilities for the summer seasons are calculated as a fraction of the Winter capability, as shown in Figure 8.

Boundaries	Winter	Summer_Intact	Summer_Outage
B4 B6 B7a	100%	85%	70%
B8 B9 B15	100%	90%	80%

Figure 8: Seasonal Boundary Capability Fractions

⁷ actually nine, given the variation of parameters within Approach 1b and 1c

		Approach											Min Max Range			
		Ranking Order						Non-Ranking Order								
		1a	1b1	1b2	1b3	1b4	1d	1c1	1c2	1c3	1c4	1e				
B4	GG5c	2015/16	2.8	3.2	3.1	3.1	3.0	3.0	2.6	2.6	2.8	3.4	4.1	2.6	4.1	1.5
		2020/21	4.3	5.7	5.5	5.2	5.0	4.6	4.1	4.0	4.7	5.7	6.1	4.0	6.1	2.1
		2030/31	4.7	7.2	6.7	6.3	5.9	4.9	4.3	4.0	5.1	5.9	6.4	4.0	7.2	3.2
GG5a	2015/16	2.4	2.7	2.7	2.6	2.6	2.6	2.2	2.2	2.3	2.9	3.5	2.2	3.5	1.3	
	2020/21	2.8	4.0	3.8	3.6	3.4	2.9	2.6	2.5	2.9	3.6	4.1	2.5	4.1	1.6	
	2030/31	3.2	5.4	5.0	4.6	4.2	3.4	3.0	2.8	3.4	3.8	4.5	2.8	5.4	2.6	
B6	GG5c	2015/16	5.0	5.4	5.4	5.3	5.2	5.3	4.5	4.6	4.9	5.9	6.3	4.5	6.3	1.8
		2020/21	5.8	7.9	7.6	7.2	6.9	6.2	5.3	5.3	6.4	7.8	7.9	5.3	7.9	2.6
		2030/31	5.6	9.1	8.5	7.9	7.3	5.9	5.0	4.6	6.2	7.1	7.4	4.6	9.1	4.6
GG5a	2015/16	4.2	4.7	4.6	4.6	4.5	4.4	3.7	3.8	4.1	5.0	5.3	3.7	5.3	1.6	
	2020/21	3.2	5.4	5.0	4.6	4.3	3.4	2.9	2.9	3.4	4.3	4.5	2.9	5.4	2.5	
	2030/31	3.2	6.5	5.9	5.3	4.8	3.4	2.8	2.4	3.2	3.7	4	2.4	6.5	4.1	
B7a	GG5c	2015/16	7.1	7.7	7.6	7.5	7.4	7.1	6.5	6.7	7.1	8.1	8.2	6.5	8.2	1.7
		2020/21	7.3	9.9	9.4	9.0	8.6	7.2	6.4	6.5	7.6	8.3	8.3	6.4	9.9	3.5
		2030/31	5.8	10.0	9.2	8.5	7.9	5.7	4.9	4.3	5.8	6.4	6.6	4.3	10.0	5.7
GG5a	2015/16	6.3	7.0	6.9	6.8	6.7	6.3	5.7	6.0	6.2	7.1	7.2	5.7	7.2	1.5	
	2020/21	4.7	7.7	7.1	6.7	6.2	4.6	4.0	4.1	4.7	4.9	4.9	4.0	7.7	3.7	
	2030/31	3.4	7.8	6.9	6.2	5.5	3.3	2.7	2.1	2.8	3.0	3.2	2.1	7.8	5.6	
B8	GG5c	2015/16	9.8	10.5	10.4	10.3	10.2	9.5	9.4	9.4	9.6	10.4	10.2	9.4	10.5	1.2
		2020/21	9.4	12.5	12.0	11.5	11.1	9.1	9.0	8.9	9.5	9.5	9.4	8.9	12.5	3.6
		2030/31	4.6	8.9	8.2	7.5	6.8	4.0	5.8	4.9	5.9	6.0	5.8	4.0	8.9	4.9
GG5a	2015/16	9.8	10.5	10.4	10.3	10.2	9.5	9.3	9.4	9.6	10.4	10.2	9.3	10.5	1.2	
	2020/21	8.7	12.1	11.5	11.0	10.5	8.4	8.3	8.2	8.7	8.6	8.4	8.2	12.1	3.9	
	2030/31	3.9	8.5	7.7	6.9	6.2	3.4	5.1	4.3	5.1	5.0	4.9	3.4	8.5	5.1	
B9	GG5c	2015/16	10.7	11.6	11.5	11.3	11.2	10.6	10.0	9.9	10.0	10.2	10	9.9	11.6	1.7
		2020/21	9.3	12.6	12.1	11.6	11.1	9.2	8.4	8.1	8.3	7.4	7.4	7.4	12.6	5.2
		2030/31	1.3	9.6	8.0	6.6	5.2	1.6	2.3	1.3	2.1	1.8	1.6	1.3	9.6	8.3
GG5a	2015/16	10.7	11.6	11.5	11.3	11.2	10.6	10.0	9.9	10.0	10.2	10	9.9	11.6	1.7	
	2020/21	9.3	12.6	12.1	11.6	11.1	9.2	8.4	8.1	8.3	7.4	7.4	7.4	12.6	5.2	
	2030/31	1.3	9.6	8.0	6.6	5.2	1.6	2.3	1.3	2.1	1.8	1.6	1.3	9.6	8.3	
B15	GG5c	2015/16	6.9	7.6	7.5	7.4	7.2	6.8	6.6	6.6	6.6	7.1	7.5	6.6	7.6	0.9
		2020/21	6.7	9.0	8.6	8.2	7.8	6.5	6.2	6.4	6.2	7.1	7.4	6.2	9.0	2.9
		2030/31	8.0	12.1	11.3	10.5	9.9	7.6	7.5	7.5	6.6	7.6	8	6.6	12.1	5.5
GG5a	2015/16	6.9	7.6	7.5	7.4	7.2	6.8	6.6	6.6	6.6	7.1	7.5	6.6	7.6	0.9	
	2020/21	6.7	9.0	8.6	8.2	7.8	6.5	6.2	6.4	6.2	7.1	7.4	6.2	9.0	2.9	
	2030/31	8.0	12.1	11.3	10.5	9.9	7.6	7.5	7.5	6.6	7.6	8	6.6	12.1	5.5	

Figure 9: Required Boundary Capabilities (GW), by Approach

The following observations can be made:

- The range of required capability by Approach can be modest or quite large. For example, B6 in GG5a 2015 ranges from 3.7 to 4.7GW, but B8 in GG5c 2020 ranges from 8.9 to 12.5GW.
- The required capability for a particular boundary over the three years we are analysing may be very different. For example, the B9 1b1 GG5c requirement is 11.6GW 2015/16, and this rises to 12.6GW in 2020/21, only to fall away sharply to 9.6GW in 2030/31.
- The set of required capabilities for GG5c and GG5a for B9 are identical, and the same is true for B15. This is since the relocation of wind capacity between the two *Gone Green* scenarios occurs only to the north of these boundaries.
- Capabilities for Approach 1a and 1c1-1c3 are always lower than the corresponding capabilities for 1b1-1b4, with the latter ordered from 1b1 (highest) to 1b4 (lowest). This directly reflects the assigned wind import A_T factors for 1b1-1b4.
- For B9 in 2030/31, what in previous years had been the export zone (north of the boundary) and the import zone (south) were swapped around to return the highest required capability.

- Approach 1d is not very different from 1a and 1c3. Approach 1d capability either falls between approach 1a and 1c3 or is very close to 1a.
- Approach 1c4 is slightly higher than 1b1 in 2020/21 compared to 1c1-1c3.
- Approach 1e is quite similar to 1c4; 1e either falls on the same range with 1c4 or is slightly higher or lower.

Constraint Results

Detailing an individual Constraint study against the boundary capability required for each of the six approaches above may not show the cost curve to its best advantage, and so we interpolate to perform five Constraint runs between the minimum and maximum required capability for each row in Figure 9, plus two additional runs below the minimum and above the maximum. Thus we end up at 7 capabilities × 6 boundaries × 3 years × 2 scenarios = 252 Constraint studies.

Each study is performed against that boundary alone – i.e. all other boundaries are set to 99,999MW (ie. effectively infinite capability).

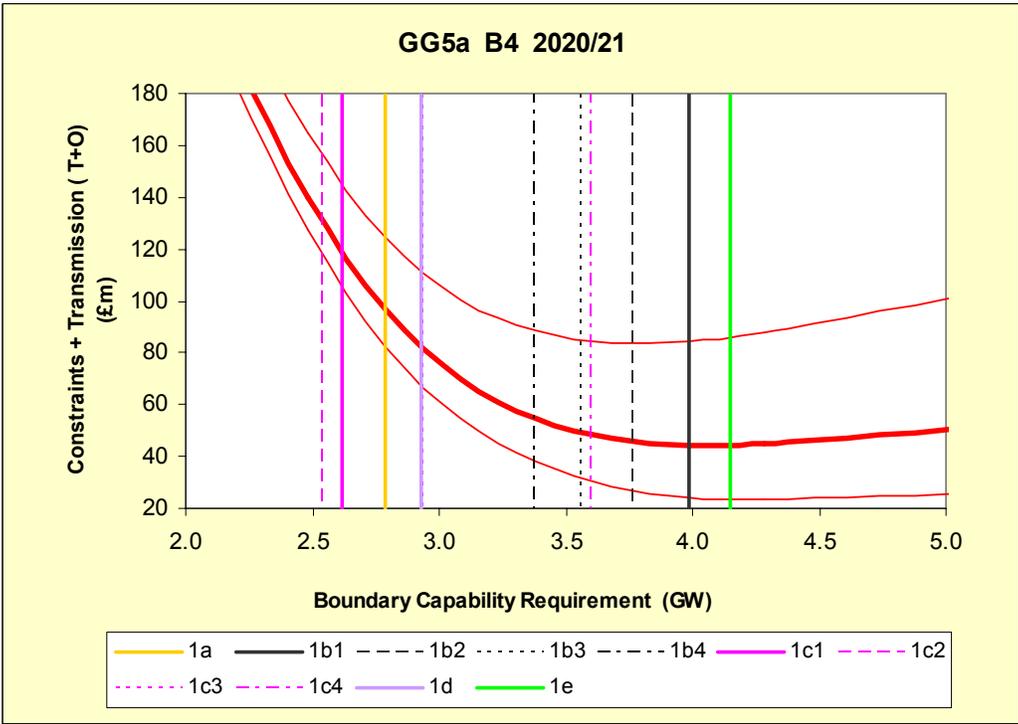
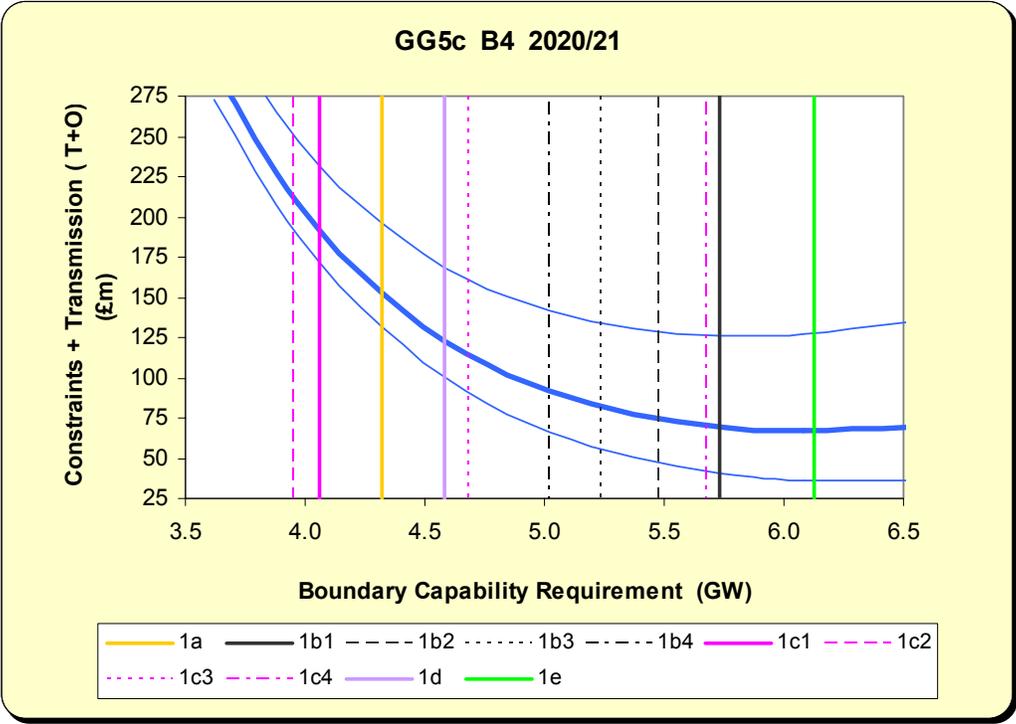
By 2020 for B6 the required capability by Approach ranges from 5.4-7.9GW – far greater than the current capability, due to the high level of wind commissioning in Scotland. The constraint costs as always are approximately quadratic, rising rapidly for capability values below 6.9GW (£41m) and breaching £200m at 5.4GW. When the capability approaches 8GW, constraint costs on this boundary are under £10m pa.

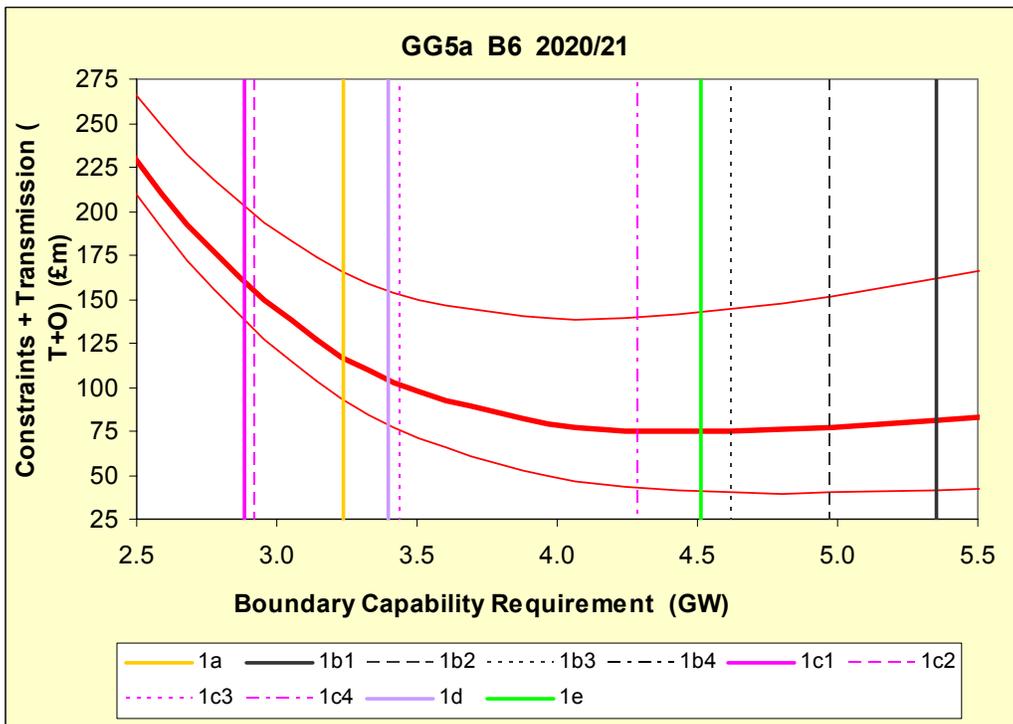
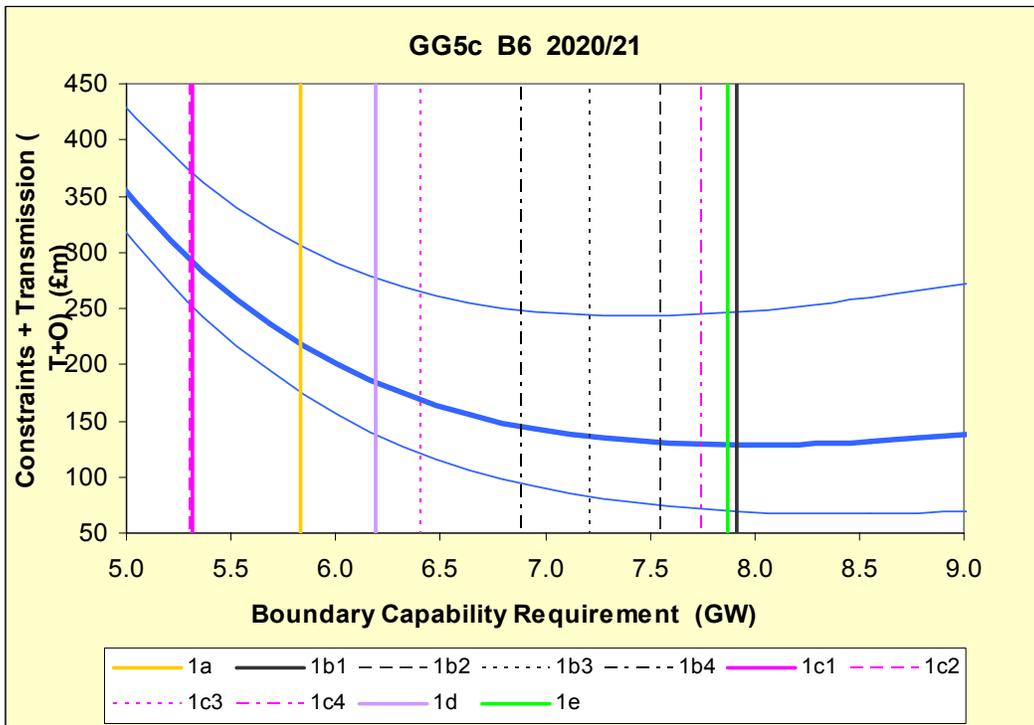
T+O Results

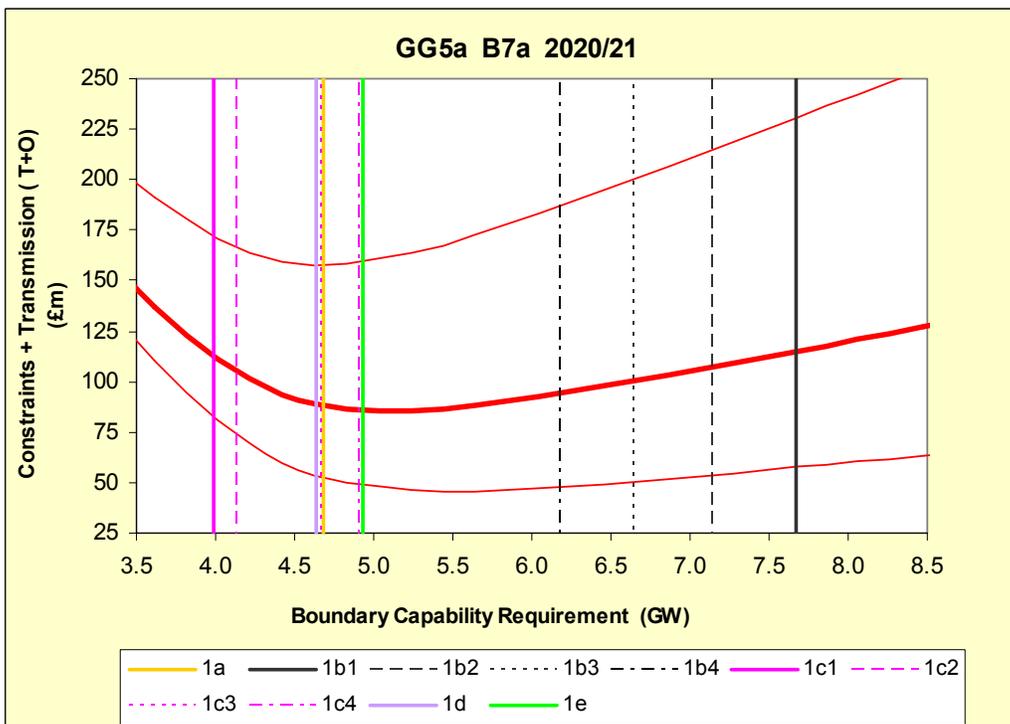
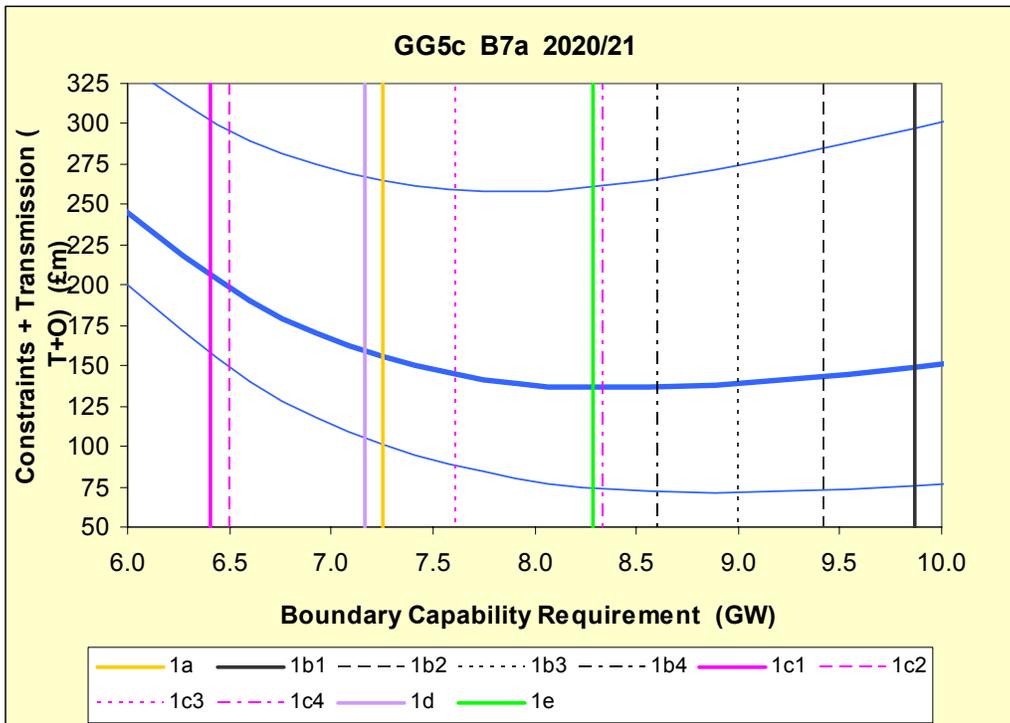
For each of combination of boundary and scenario, we plot T+O against boundary capability and flag the boundary capability required by each of the eight Approaches. Here, we have only shown the 2020/21 results (figure 11).

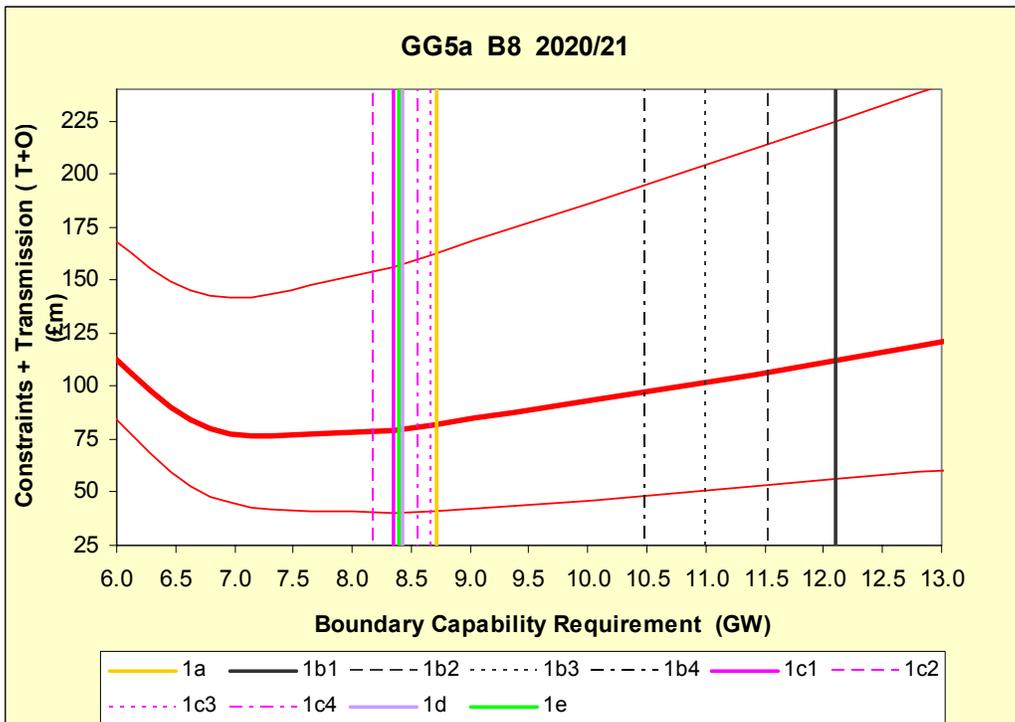
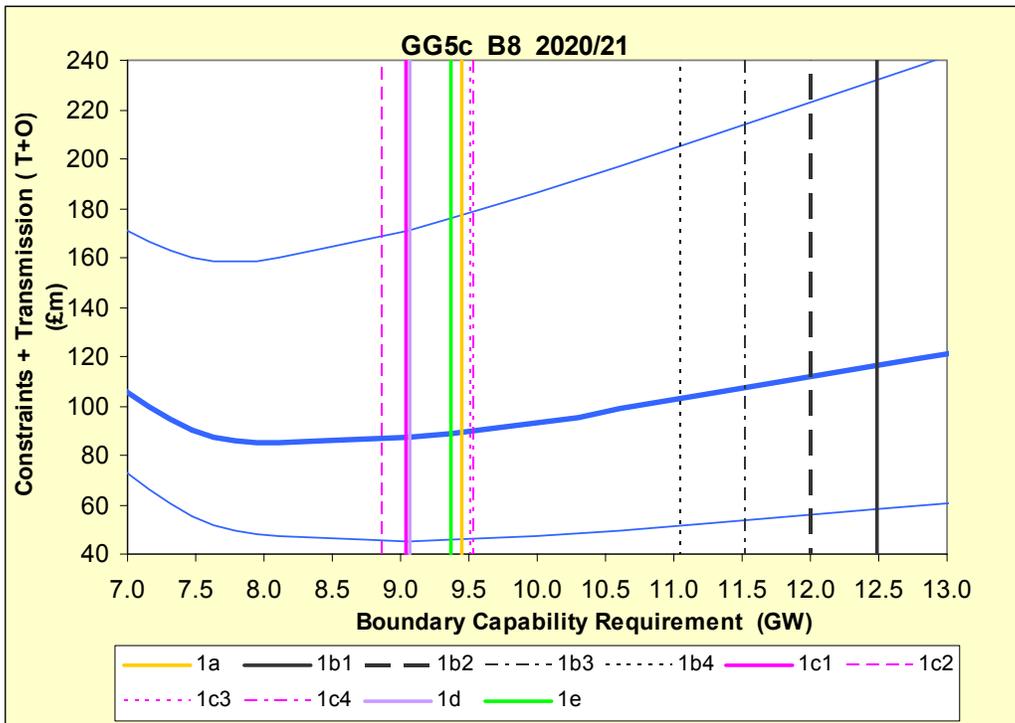
By eye we can identify the optimum boundary capability (ie. the minimum of the T+O curve) and identify the corresponding T+O cost (Figure 11). We have also identified an “optimum capability range” where the T+O cost are less than £5m above the minimum. This chart has been colour-coded using a ‘traffic light’ system, to help identify, for each boundary, those approaches that are most and least appropriate.

It is worth noting that for Approach 1b boundary capabilities are consistently ordered *1b4, 1b3, 1b2, 1b1 (highest)*.









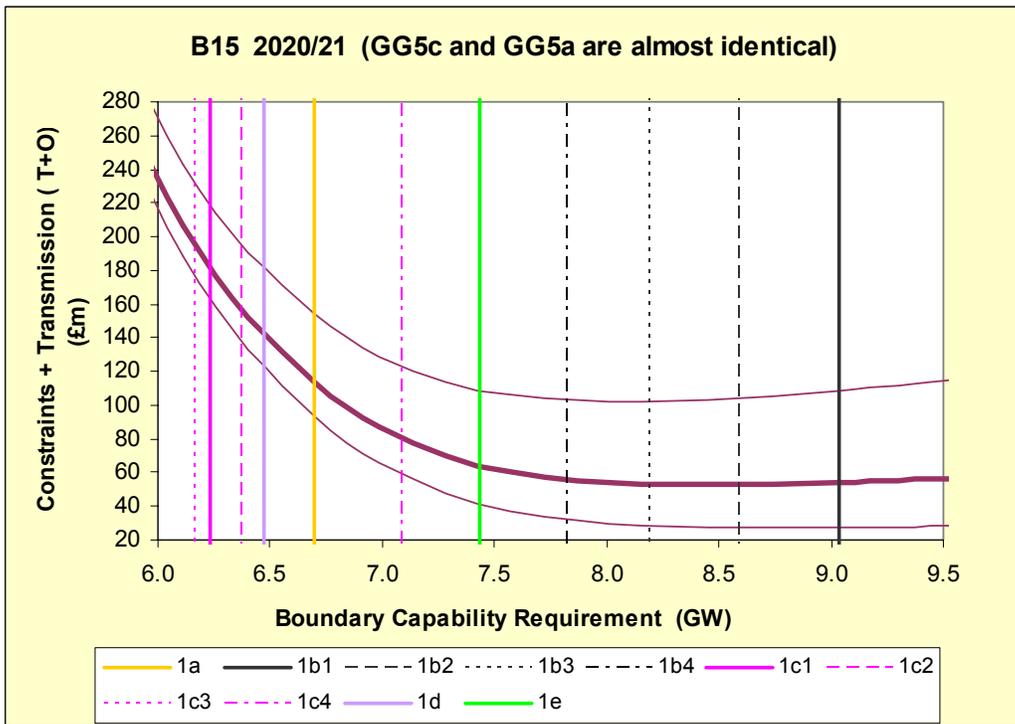
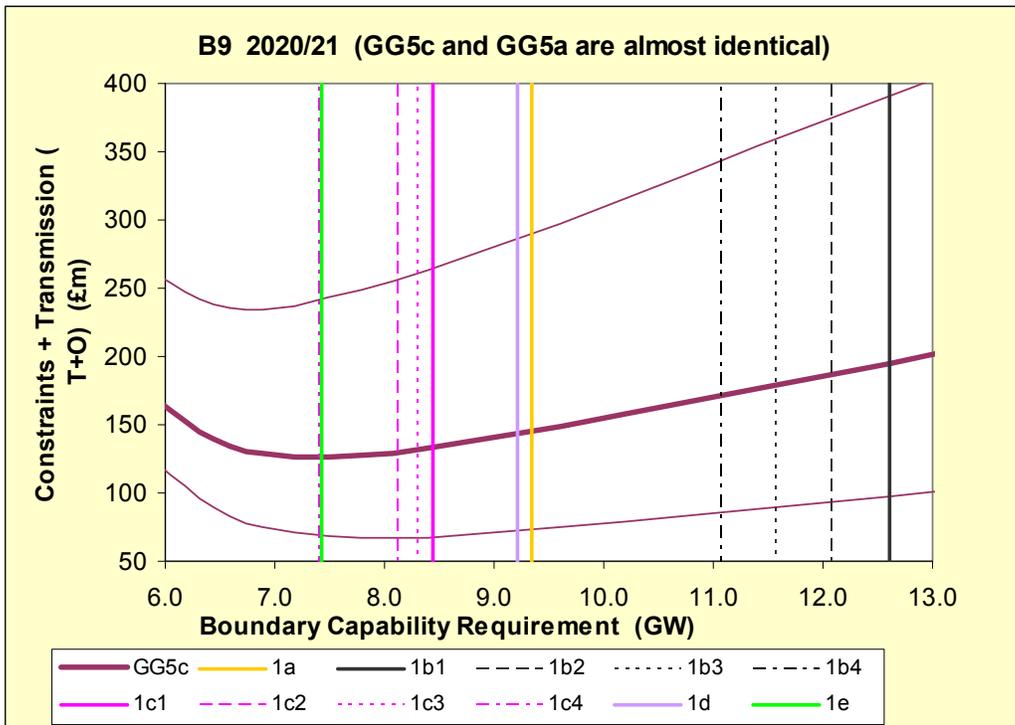


Figure 10: 2020/21 T+O Results

Boundary Thickness (km)	Background	Ranking Order Approach										Non-Ranking Order Approach					Optimum	
		1a	1b1	1b2	1b3	1b4	1d	1c1	1c2	1c3	1c4	1e	GW T+O	Range				
B4	100	GG5a	GW	2.8	4.0	3.8	3.6	3.4	2.9	2.6	2.5	2.9	3.6	4.1	4.1	3.6 - 4.8		
		T+O	£96m	£44m	£46m	£49.5m	£55m	£84m	£120m	£132m	£84m	£50m	£44m	£44m	< £49m			
		Δ GW from Optimum	-1.3	-0.1	-0.3	-0.5	-0.7	-1.2	-1.5	-1.6	-1.2	-0.5	0.0	0.0				
	Δ T+O from Optimum	£52m	£0m	£2m	£6m	£11m	£40m	£78m	£88m	£40m	£6m	£0m						
	GG5c	GW	4.3	5.7	5.5	5.2	5.0	4.6	4.1	4.0	4.7	5.7	6.1	6.0	5.6 - 7.2			
	T+O	£152.5m	£69m	£74m	£82m	£91m	£125m	£194m	£212m	£114m	£74m	£73m	£67m	< £72m				
Δ GW from Optimum	-1.7	-0.3	-0.5	-0.8	-1.0	-1.4	-1.9	-2.0	-1.3	-1.3	0.1	0.1						
Δ T+O from Optimum	£86m	£2m	£7m	£15m	£24m	£58m	£127m	£145m	£47m	£7m	£6m							
B6	150	GG5a	GW	3.2	5.4	5.0	4.6	4.3	3.4	2.9	2.9	3.4	4.3	4.5	4.6	3.9 - 5.2		
		T+O	£117m	£81m	£76.5m	£75m	£76m	£111m	£170m	£163m	£108m	£75m	£75m	£74.5m	< £79.5m			
		Δ GW from Optimum	-1.4	0.8	0.4	0.0	-0.3	-1.2	-1.7	-1.7	-1.2	-0.3	-0.1	-0.1				
	Δ T+O from Optimum	£43m	£7m	£2m	£1m	£2m	£36m	£96m	£89m	£34m	£0m	£0m						
	GG5c	GW	5.8	7.9	7.6	7.2	6.9	6.2	5.3	5.3	6.4	7.8	7.9	8.0	7.3 - 8.8			
	T+O	£218m	£129m	£130.5m	£135.5m	£144.5m	£187.0m	£293m	£294m	£172m	£136m	£136m	£129m	< £134m				
Δ GW from Optimum	-2.2	-0.1	-0.4	-0.8	-1.1	-1.8	-2.7	-2.7	-1.6	-0.2	-0.1	-0.1						
Δ T+O from Optimum	£89m	£0m	£2m	£7m	£16m	£58m	£164m	£165m	£43m	£7m	£7m							
B7a	150	GG5a	GW	4.7	7.7	7.1	6.7	6.2	4.6	4.0	4.1	4.7	8.3	4.9	5.1	4.6 - 5.8		
		T+O	£87.5m	£115m	£107m	£100m	£94m	£91m	£117m	£109m	£91m	£89m	£89m	£85m	< £90m			
		Δ GW from Optimum	-0.4	2.6	2.0	1.6	1.1	-0.5	-1.1	-1.0	-0.4	3.2	-0.2	-0.2				
	Δ T+O from Optimum	£3m	£30m	£22m	£15m	£9m	£6m	£32m	£24m	£6m	£4m	£4m						
	GG5c	GW	7.3	9.9	9.4	9.0	8.6	7.2	6.4	6.5	7.6	4.9	8.3	8.4	7.8 - 9.2			
	T+O	£156m	£148.5m	£143.5m	£139m	£137m	£160m	£212m	£201m	£147m	£138m	£138m	£136.5m	< £141.5m				
Δ GW from Optimum	-1.1	1.5	1.0	0.6	0.2	-1.2	-2.0	-1.9	-0.8	-3.5	-0.1	-0.1						
Δ T+O from Optimum	£20m	£12m	£7m	£3m	£1m	£24m	£78m	£65m	£10m	£2m	£1m							
B8	93	GG5a	GW	8.7	12.1	11.5	11.0	10.5	8.4	8.3	8.2	8.7	8.6	8.4	7.3	6.8 - 8.5		
		T+O	£82m	£112.5m	£107.5m	£102.5m	£97.5m	£80.9m	£80m	£79m	£83m	£83m	£81m	£76m	< £81m			
		Δ GW from Optimum	1.4	4.8	4.2	3.7	3.2	1.1	1.0	0.9	1.4	1.3	1.1	1.1				
	Δ T+O from Optimum	£6m	£37m	£32m	£27m	£22m	£5m	£4m	£3m	£7m	£7m	£5m						
	GG5c	GW	9.4	12.5	12.0	11.5	11.1	9.1	9.0	8.9	9.5	9.5	9.4	7.7	7.4 - 9.7			
	T+O	£89m	£117m	£112m	£107m	£103m	£88m	£88m	£87m	£91m	£90m	£90m	£86m	< £91m				
Δ GW from Optimum	0.7	4.8	4.3	3.8	3.4	1.4	1.3	1.2	1.8	1.8	1.7	1.7						
Δ T+O from Optimum	£3m	£31m	£26m	£21m	£17m	£2m	£2m	£1m	£5m	£4m	£4m							
B9	155	iGG5a / GG5	GW	9.3	12.6	12.1	11.6	11.1	9.2	8.4	8.1	8.3	7.4	7.4	7.3	6.7 - 8.3		
		T+O	£146m	£195m	£187m	£179m	£172m	£144m	£135m	£131m	£133m	£128m	£128m	£127m	< £132m			
		Δ GW from Optimum	2.0	5.3	4.8	4.3	3.8	1.9	1.1	0.8	1.0	0.1	0.1	0.1				
Δ T+O from Optimum	£19m	£68m	£60m	£52m	£45m	£17m	£8m	£4m	£6m	£1m	£1m							
B15	60	iGG5a / GG5	GW	6.7	9.0	8.6	8.2	7.8	6.5	6.2	6.4	6.2	7.1	7.4	8.4	7.7 - 9.5		
		T+O	£113m	£55m	£53m	£53m	£56m	£150m	£188m	£165m	£198m	£80m	£60m	£53m	< £58m			
		Δ GW from Optimum	-1.7	0.6	0.2	-0.2	-0.6	-1.9	-2.2	-2.0	-2.2	-1.3	-1.0	-1.0				
Δ T+O from Optimum	£60m	£2m	£0m	£0m	£3m	£97m	£135m	£112m	£145m	£27m	£7m							
Total ΔT+O from Optimum		GG5a	£183m	£144m	£118m	£101m	£100m	£201m	£351m	£320m	£238m	£45m	£17m					
		GG5c	£277m	£115m	£102m	£98m	£106m	£256m	£512m	£492m	£256m	£48m	£26m					
Total T+O		GG5a	£642m	£603m	£577m	£559m	£551m	£661m	£810m	£779m	£697m	£505m	£477m	£460m				
		GG5c	£875m	£714m	£700m	£696m	£704m	£854m	£1110m	£1096m	£855m	£646m	£625m	£599m				

Figure 11: Optimum points on the T+O Curve for 20/21

Examining the charts in figure 11, and the values in Figure 11, we observe the following results by boundary:

B4

- T+O costs range from £44m-£132m (GG5a) and from £69m-£212m (GG5c).
- Any of 1b1-1b4, 1c4 and 1e Approaches are closest to optimal (£44m GG5a and £67m GG5c); whereas the 1a, 1d and 1c1-1c3 approaches are much worse, offering 1-2GW too low a boundary capability, and +£50-£100m pa too great a T+O cost.

B6

- T+O costs range from £75m-£180m (GG5a) and from £129m-£295m (GG5c).
- Again, 1b1-1b4, 1c4 and 1e Approaches are closest to optimal (£75m GG5a and £129m GG5c); whereas both 1a, 1d and 1c1-1c3 are much worse as they do not provide a high enough boundary capability.

B7a

- T+O costs range from £87m-£117m (GG5a) and from £138m-£212m (GG5c).
- The optimum is £89m for GG5a and £138m for GG5c. A good number of Approaches is noticeably not very bad, and either of 1c4, 1e or 1a is just about preferable.

B8

- T+O costs range from £78m-£113m (GG5a) and from £87m-£117m (GG5c).
- Any of 1a, 1d, 1c1-1c4 and 1e appears best, with 1b1 and 1b2 least attractive, but the cost curve is rather flat and thus there is not a particularly strong ranking.

B9

- T+O costs range from £128m-£195m (GG5a/GG5c).
- Approach 1c1-1c4 and 1e are closest to optimal (£128m) with any of the 1b approaches offering grossly excess capability.

B15

- T+O costs range from £53m-£198m (GG5a/GG5c).
- As for boundary B4, approaches 1b1 and 1e are close to optimal (£53m); whereas approaches 1a 1d and 1c1-3 require too low a boundary capability.
- 1a (£113m) yields some 1.7GW too low a boundary capability.
- 1a (£113m) yields some 1GW too low a boundary capability.

Approach 1a:

- Performed badly on B4, B6, B9 and B15 but was fairly good on B8.
- The total T+O from optimum looks very high and the total T+O appears excessive.

Approaches 1b1-1b4:

- Performed moderately well on B4,B6, B15 but very poorly on B8, B9, B7a(GG5a)
- The total T+O from optimum looks slightly low compared to approach 1a, 1d and 1c1-1c3, while the total T+O emerges considerably high but still lower than approaches 1a, 1d, 1c1-1c3.

Approach 1c1-1c3:

- Displayed really bad result on B4, B6, B7a and B15 but looks noticeably better on B8
- The total T+O from optimum looks incredibly high and does possess the highest compared to the other approach. The total T+O also appear enormously high.

Approach 1c4:

- Performed quite well on all the boundaries apart from B15
- The total T+O from optimum appears considerably low compared to approach 1a, 1d, 1b1-1b4 and 1c1-1c3. The total T+O, we believe, falls into the acceptable range and 1c4 looks like a possible contender compared the other approached 1c1-1c3.

Approach 1d:

- Performed consistently poorly on B4, B6, B7a and B15 but showed some positive improvement on B8.
- The total T+O from optimum looks high and the total T+O appears quite high as well.

Approach 1e:

- Performed satisfactorily well on all the boundaries
- The total T+O from optimum achieved very low cost which is far better than any of the approaches above. The T+O looks low compared to any other approach and we consider it to be the strongest contender.

Sensitivities

Cost-Benefit Pricing Sensitivities

As well as the above results (which, in this sense, are sensitivities by boundary and scenario) we also have to perform sensitivities within the cost-benefit itself. As in the GSR001 Consultation, we can compress these to:

- Either doubling the Constraint price or halving the Transmission price⁸
- Either halving the Constraint price or doubling the Transmission price

⁸ The point here is that doubling *both* the Constraint and the Transmission price simultaneously leaves the cost-benefit optimum unchanged; and hence the winning SQSS approach is unaffected.

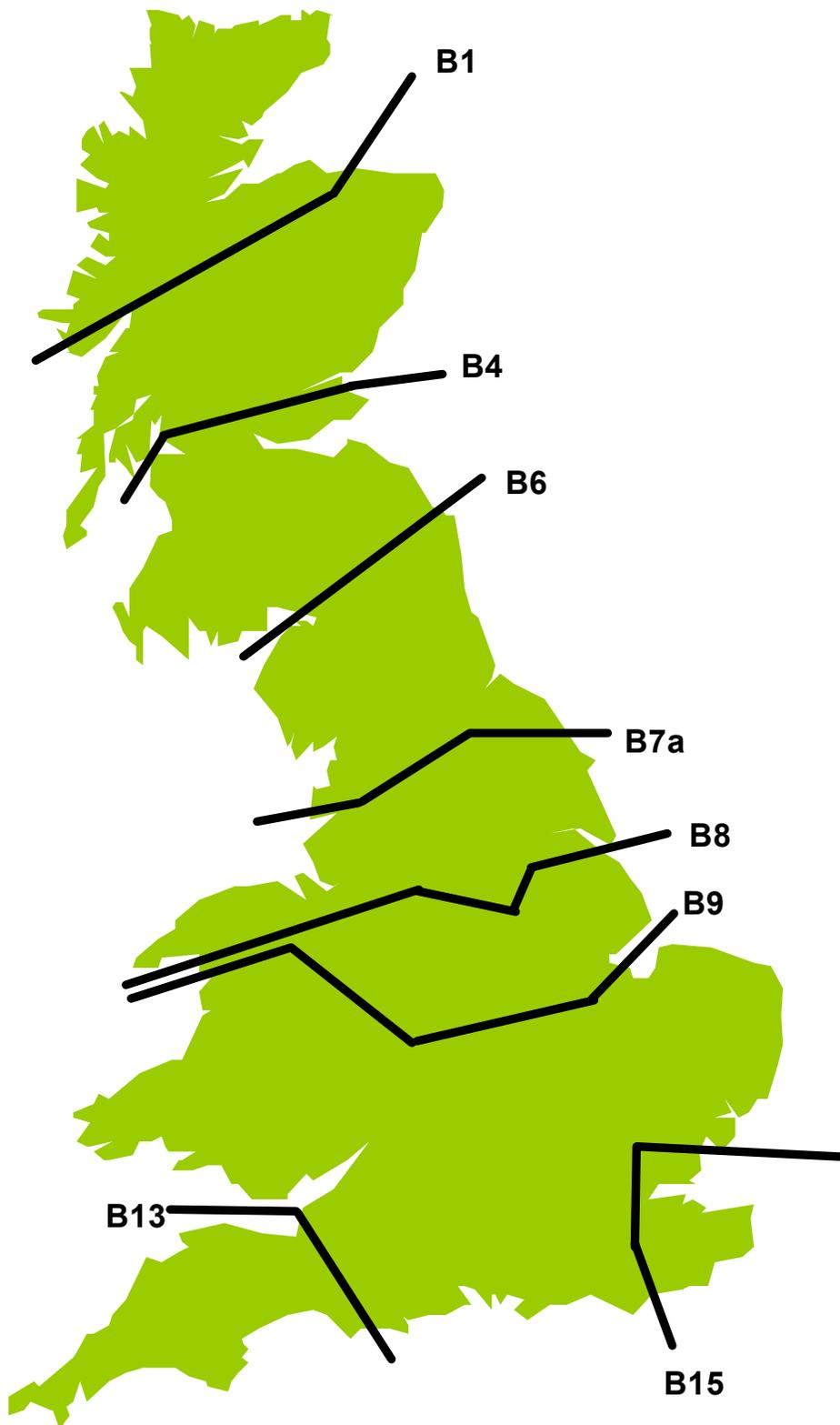
- Either quartering the Constraint price or quadrupling the Transmission price

Figure 11 shows the 'Price-doubling' and 'Price halving' sensitivities. It can be seen that the optimum points (ie. minimum T+O) typically move by <0.5GW; such that the above conclusions broadly hold. Hence the details of these two major sensitivities are not here reported further.

Conclusions

- For the 'smaller' boundaries B4 B6 B15, approaches 1b1-1b4, 1c4, 1e look best.
- But for the 'larger' boundaries B7a B8 B9, any of 1a, 1c3, 1c4, 1d, 1e look best.
- The 'regrets' of greater Constraints O if one under-builds, are greater than the regrets of extra Transmission, if one over-builds.

Appendix 6 – System Boundaries



Appendix 7 – Links to Reference Documents

April 2010 SQSS fundamental review consultation

<http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/fundamental/April+2010+Consultation/April+2010+Consultation.htm>

Industry open letter on SQSS review

<http://www.nationalgrid.com/NR/ronlyres/CFF78A12-949C-4D87-B8FD-F51FE156D9E6/40409/SQSSOpenLetter300310.pdf>

GSR001 report

http://www.nationalgrid.com/NR/ronlyres/B6B8CABD-6D2C-4D1E-A48F-51789CA93484/22606/GBSQSS_Review_for_Onshore_Intermittent_Generation.pdf

National Grid Gone Green Scenario data

<http://www.nationalgrid.com/NR/ronlyres/9A4B4080-3344-4C6D-8A19-411A867682F2/26834/GoneGreenfor2021.pdf>

National Grid Seven Year Statement

<http://www.nationalgrid.com/uk/Electricity/SYS/current/>

ENSG Report

http://www.ensg.gov.uk/assets/ensg_transmission_pwg_full_report_final_issue_1.pdf

Transmission Access Review

<http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx>