Integrated Single Electricity Market

(I-SEM)

Interconnector De-Rating Factor

Methodology Decision

Appendix 2

SEM-16-082b

Contents

1. INTRODUCTION

1.1 BACKGROUND

1.1.1 Following the first CRM consultation, as part of CRM Decision 1 (SEM-15-103), the SEM Committee decided that:

"the procurement of Reliability Options under the I-SEM should be based on a de-rated requirement."

and further that this de-rated requirement should be determined using de-rating factors developed as follows:

"Central de-rating factors will be technology specific, but make allowance for the impact of plant size. [De-rating factors will] be based on marginal contribution to meeting the capacity requirement."

1.1.2 Concerns were raised by stakeholders during the second CRM Consultation about the conflicts of interest which could occur if the TSOs were to develop de-rating factors for the interconnectors. Responding to these concerns, the SEM Committee decided in CRM Decision 2 (SEM-16-022) that:

"RAs should develop a methodology to determine the de-rating factors to be applied to interconnectors."

1.1.3 There are a number of specific issues with determination of a de-rating factor for the interconnectors. In particular, in addition to the technical unavailability of the interconnector asset itself, the ability of an interconnector to deliver capacity to the I-SEM at times of high price or scarcity would depend on the availability of surplus capacity in external, connected markets as well as the price in those markets.

1.1.4 Given this absence of historic data directly relating to the operation of the I-SEM, and changes to the GB market, and taking account of responses received to the second CRM Consultation, the SEM Committee decided that:

"the methodology will be based on suitable historic and forecast data for GB and the SEM. "

1.1.5 This paper sets out the methodology to be used to determine de-rating factors for the interconnectors. The numbers used in this paper were taken from publicly available sources as of July 2016 and the values shown should be considered indicative only.

1.1.6 The sections of this paper are organised as follows:

- Section 2 "**Overview of Methodology**" provides a high-level overview of the methodology employed and the basic rationale for this methodology.
- Section 3 "**Demand Forecasting**" details the generation of the half-hourly demand forecasts used to produce the scenarios considered by the methodology.

- Section 4 "**Wind Forecasting**" details the generation of the wind forecasts used to produce the scenarios considered by the methodology.
- Section 5 **"Solar Profiles"** details the profiles used to estimate the level of production from solar capacity in GB.
- Section 6 "**Operational Reserve Requirements**" details the reserve scenarios considered by the methodology.
- Section 7 "**Other Scenario Inputs**" details the other inputs used to generate scenarios considered by the methodology.
- Section 8 "**Determining Effective Capacity**" details how the scenarios are analysed to produce a forecast of scarcity in both the I-SEM and GB and hence an effective capacity for interconnector imports.
- Section 9 "**Interconnector Technical Availability**" details the analysis of historic planned and forced outages rates on the existing interconnectors.
- Section 10 **"Indicative Results**" details the results of the analysis and indicative results.

2. OVERVIEW OF THE METHODOLOGY

2.1 ISSUES

2.1.1 There are two key areas which need to be addressed in determining the de-rating factor for an interconnector:

- the probability that capacity will be available to import from GB at times of scarcity in the I-SEM; and
- the probability that the interconnector will be technically available at times of scarcity in the I-SEM.

2.1.2 Determination of the technical availability of the interconnector(s) can be addressed by examination of historic outage data. This will be based on the last 10 years for which complete data is available.

2.1.3 Determination of the probability that capacity will be available to import to the I-SEM at times of scarcity, and thus of the effective capacity of an interconnector, is more problematic.

2.1.4 As discussed in CRM Decision 2 (SEM-16-022), the use of either flows between GB and the SEM or historic price differentials between GB and the I-SEM to determine whether power will flow into the I-SEM at times of scarcity is problematic as:

- the I-SEM market design is substantially different to the SEM design to which any historic data relates. For example, with the move to the I-SEM we have removed the Pool price cap of €1000/MWh that applies in the SEM, and introduced an Administrative Scarcity Pricing (ASP) function, with the Full ASP set initially at €3,000/MWh; and
- the GB market has also undergone significant recent change, e.g. the introduction of the carbon floor price in 2013, the EBSCR[1] change to balancing market price formation, which has introduced ASP in the GB electricity market, initially at a price of £3,000/MWh, and the introduction of a capacity market.

There is a further issue with the use of much available historic data as the whole period of the SEM is one for which markets Europe-wide were carrying surplus capacity and so includes very limited (if any) events of scarcity.

2.1.5 The use of fundamental modelling of the GB and SEM markets to forecast whether imported capacity will be available at times of SEM scarcity is also difficult given the lack of viable historic data to be used for calibration. In addition, the range of assumptions that would be needed to underpin any modelling of the I-SEM would be significant. Fundamental modelling is computationally extremely complex and this limits the number of scenarios that could be modelled. These issues would cast doubt on the results of any such modelling.

[1] Ofgem's Electricity Balancing Significant Code Review (EBSCR)

2.1.6 As a result, a methodology was selected which uses historic data unaffected by the changes to the I-SEM market design or the changes in GB. This focuses on the use of historic temperature, demand, wind and outage data. This historic data is coupled with forecasts for future demand, plant mix and reserve requirements to generate a very large number of scenarios for a forecast year.

2.1.7 It should be noted that the expected prices in the SEM and GB at times of scarcity have not been directly considered in this methodology. However, scarcity in GB will generate high prices in GB and this will draw exports from the I-SEM. These exports could push the I-SEM into scarcity and this situation has been considered as discussed below.

2.1.8 Otherwise, it has been assumed, in line with the current interconnector agreements, that at times of scarcity in the I-SEM energy will flow across the interconnector unless there is simultaneous scarcity in GB. It is assumed that the scarcity pricing being implemented in the I-SEM will also provide suitable economic signals for such flow: however, the full detail of scarcity pricing is part of the current CRM Parameters Consultation (SEM-16-073) which closes on 21 December 2016. This assumption may require review once the I-SEM enters operation and as further changes are made to the GB market design.

2.1.9 A further issue exists if the price in GB rises above the Reliability Option (RO) strike price in the I-SEM. In autumn 2016, GB prices rose above the expected strike price in both the DAM and BM on multiple occasions, but this relative scarcity in GB is being driven by the more than 4GW of capacity which is part of the Supplemental Balancing Reserve and is unable to participate in the market. The Supplemental Balancing Reserve will cease before the CRM goes live and it is not clear that such high prices will persist in GB.

2.1.10 The methodology identifies scarcity in GB if the available capacity is unable to meet the sum of demand and operating reserve. During the DAM and IDM, generation only needs to satisfy demand: so, under the methodology, scarcity is considered to exist in GB even if demand is 3GW less than the available capacity. This “buffer” means that the methodology is already taking a conservative view of the risks of scarcity in GB which should capture those times when GB prices rise above the RO strike price.

2.1.11 The RAs do not intend further reducing the de-rating factor for the interconnectors as a result of recent high prices in GB. This position will be revisited when the enduring, hybrid solution for cross-border participation in the CRM is implemented.

2.2 PROPOSED METHODOLOGY

2.2.1 The basic idea behind the methodology is to simulate a very large number of winter working days (i.e. not weekends or holidays in either of NI or RoI) for a future year. This is on the basis that the vast majority of scarcity events will occur on such days, only very extreme situations would lead to scarcity over the summer or at weekends or public holidays. The potential scarcity events missed using this winter working day basis would not be statistically material.

2.2.2 Given an assumed future generation portfolio for each market (I-SEM and GB) and historic outage rates, for each half-hourly period in the days simulated, the chances of a combination of outages occurring which prevents generation from meeting demand can be estimated.

2.2.3 By creating mutually consistent estimates of the ability of generation to meet demand in both the I-SEM and GB for each period, it is possible to determine the effective capacity which imports can contribute to the CRM from the interconnector(s).

2.2.4 Each simulated winter working day is generated using the Monte Carlo method. Each day is randomly allocated a month to enable a suitable profile of expected solar production to be assigned to that day. Each simulated day uses a further five random seeds to make "picks" from historically derived distributions for temperature, SEM and GB demand, SEM and GB wind and the heavily variable element of the GB operational reserve requirement.

2.2.5 To provide a little more substance to this basic idea, Figure 1 below gives a simplified diagrammatic overview of the proposed methodology to determine the effective capacity of an interconnector.

2.2.6 The diagram illustrates determination of the probability of scarcity in I-SEM and in GB, taking account of the correlations between the key drivers affecting the I-SEM and GB market. This allows determination of the probability of coincident scarcity in the two markets, i.e. the I-SEM has scarcity and GB lacks surplus capacity and so imports through the interconnector are not possible. By looking across all half-hourly periods in a large number of potential scenario days (500,000) where scarcity could arise, it is possible to produce an estimate of the effective capacity of an interconnector.

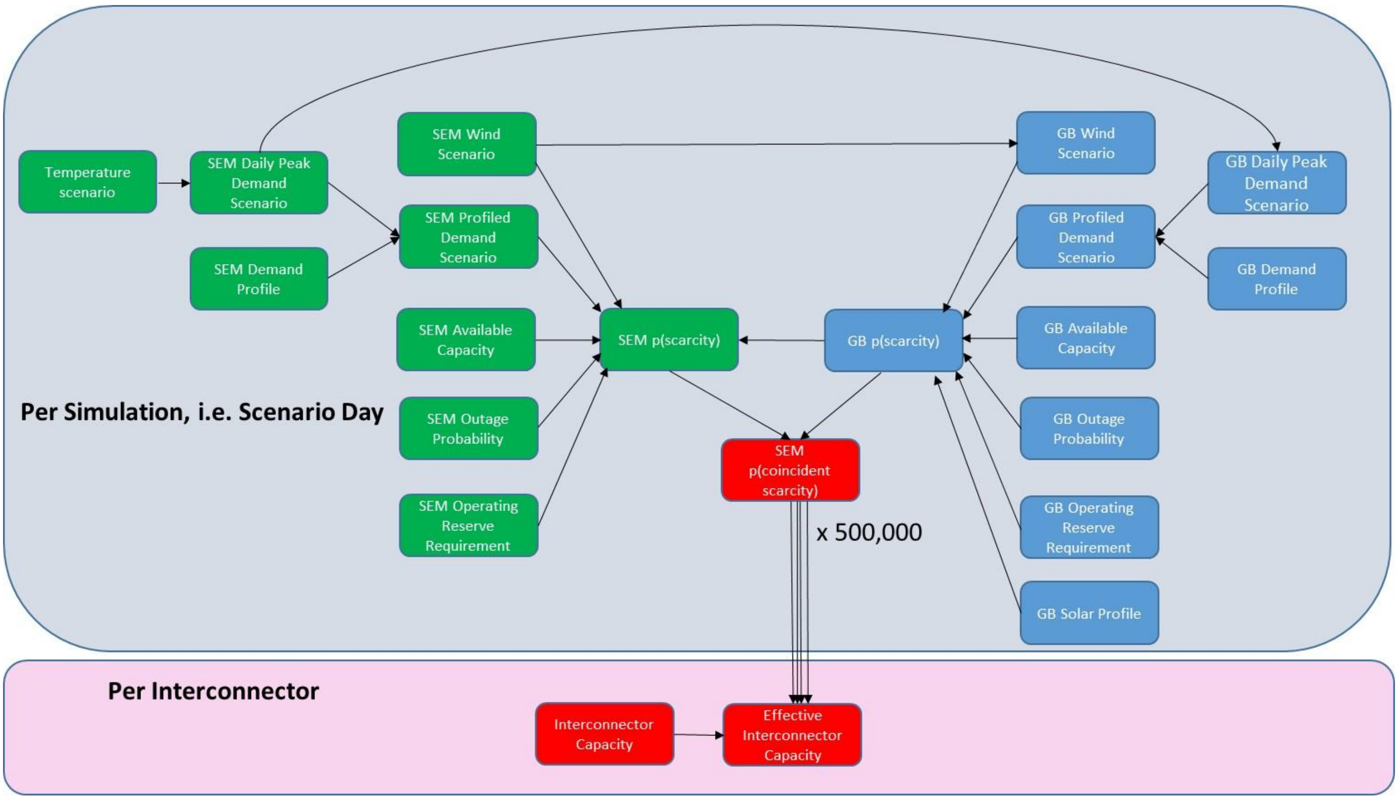

Figure 1: Simplified Methodology Overview

2.2.7 While the methodology in this appendix is defined in terms of interconnectors between the I-SEM and GB, the same methodology would be applied to any external market with an interconnection or proposed interconnection to the I-SEM. The methodology for a different external market may require some adjustments based on the availability of historic and forecast data, the correlation between the drivers of scarcity in the market and the I-SEM and the relative influence of wind and solar generation. Any such alterations will follow the ethos of this methodology as far as possible.

Deriving the Probability of Scarcity in the I-SEM

2.2.8 The methodology starts by randomly selecting one of the six winter months, i.e. October, November, December, January, February or March.

2.2.9 A forecast of the mean temperature for the I-SEM is then generated for each scenario day. This is a Monte Carlo pick taken from a distribution of temperatures based on historic weather data for the selected month.

2.2.10 A scenario value for I-SEM Peak Demand is then derived from this temperature, allowing for the historic distribution of peak demand for any given daily mean temperature.

2.2.11 A profile of how historic half-hourly I-SEM demand is related to daily peak demand for the selected month is then used to determine a half-hourly profile of demand for the scenario day (**SD_b**).

2.2.12 A Monte Carlo pick is used to pick a level of I-SEM wind generation for the scenario day (**SW_d**). This pick is taken from a distribution of wind output derived from historic production data.

2.2.13 A forecast of the expected I-SEM operating reserve requirement is made, based on 100% of the Largest Single Infeed (**SR**).

2.2.14 A forecast of the expected I-SEM capacity, less that provided from wind, is made (**SC**).

2.2.15 The probability of scarcity endogenous to the I-SEM is then determined as follows for each half-hourly period:

- Determine the expected surplus (or shortfall) of capacity in the I-SEM, without accounting for outages of conventional plant. I.e. the forecast demand plus operating reserve requirement less the expected capacity: $SC – (SD_b + SR – SW_d)$
- Determine the probability of sufficient, simultaneous outages occurring in the I-SEM to exceed any surplus of capacity (i.e. to generate a zero surplus or shortfall).

This latter is then the probability of scarcity occurring in the I-SEM, i.e. that the demand will exceed the availability capacity, accounting for outages: call this **$p(S_{end})$.**

Deriving the Probability of Scarcity in the GB

2.2.16 Determining the probability of scarcity in GB uses a process entirely analogous to that used for the I-SEM.

2.2.17 As GB peak demand is strongly correlated to I-SEM peak demand (analysis for this appendix indicated a correlation of 95%), it is important to capture this linkage when considering whether GB scarcity will coincide with I-SEM scarcity. The GB peak demand for each scenario day is derived from the I-SEM peak demand, using a regression analysis of historic SEM and GB daily peak demand.

2.2.18 A profile of solar production for the day is selected from a profile for the selected month. The profiles are derived from historic estimates of half-hourly GB solar production (**GS_d**).

2.2.19 A profile of how historic half-hourly GB demand is related to daily peak demand for the selected month is then used to determine a half-hourly profile of demand for the scenario day (**GD_b**).

2.2.20 A Monte Carlo pick is used to pick a level of GB wind generation for the scenario day (**GW_d**), using a regression analysis of the historic daily level of I-SEM and GB wind production.

2.2.21 A forecast of the expected GB operating reserve requirement is made, based on the historic values of Operating Margin (OPMR) held in GB (**GR**).

2.2.22 A forecast of the expected GB capacity, less that provided from wind and solar, is made (**GC**).

2.2.23 The probability of scarcity is then determined as follows for each half-hourly period:

- Determine the expected surplus (or shortfall) of capacity in the GB, without accounting for outages of conventional plant. I.e. the forecast demand plus operating reserve requirement less the expected capacity: $GC – (GD_b + GR – GW_d - GS_d)$
- Determine the probability of sufficient, simultaneous outages occurring in the GB to exceed any surplus of capacity (i.e. to generate a zero surplus or shortfall).

This latter is then the probability of scarcity occurring in GB, i.e. that the demand will exceed the availability capacity, accounting for outages: call this **p(G)**.

Determining the De-rating to be applied to an External Market

2.2.24 As mentioned above, there is the potential for scarcity in GB to cause scarcity in the I-SEM. This can be determined using the conditional probability that there will exist scarcity in the I-SEM given that there is scarcity in GB: call this **$p(S_{end}|G)$**. This probability is estimated conservatively by considering the probability of scarcity in the I-SEM assuming the interconnectors are exporting at their maximum capability at all times.

2.2.25 Then the probability of coincident scarcity is given as:

$$\mathbf{p(S_{end} \cap G) = p(S_{end}|G) \times p(G)}.$$

2.2.26 The total probability of scarcity in the I-SEM is then the sum of the probabilities of endogenous scarcity and scarcity driven by GB: call this $\mathbf{p(S_{tot})}$.

2.2.27 The probability of capacity not being available to import from GB when I-SEM is in scarcity can then be determined by taking the weighted-average of the probability of coincident scarcity, across all the half-hourly periods of every scenario day, simulated as follows:

p(Capacity unavailable when needed) = $\sum \mathbf{p(S_{end} \cap G)} / \sum \mathbf{p(S_{tot})}$

2.2.28 This value represents the reduction in expected capacity which applies to the external market (in this case GB). This External Market De-rating Factor (EMDF), which would apply to all interconnectors between the I-SEM and the external market, can then de defined as:

EMDF = 1 - p(Capacity unavailable when needed)

2.2.29 From the value of EMDF, an Effective Capacity for an interconnector can be derived. This will be:

AIC x EMDF

where AIC is the Aggregated Import Capacity available for import.

Determining Interconnector Technical Availability

2.2.30 The technical availability for interconnectors is derived from historic outage data obtained for EWIC and Moyle. All outages are considered in this analysis, both full and partial.

2.2.31 The intention is to apply the same principles to the planned and forced outage rates for the interconnectors as is applied to conventional generator units under the TSOs De-Rating Methodology, wherever possible. This ensures consistency of treatment of the interconnectors with other generator units in respect of the impact of historic outage rates on de-rating factors.

2.2.32 The small number of interconnectors (2) and the limited history, including a very long term outage on Moyle, necessitates some minor variation to the standard methodology applied to conventional generator units. In particular, the last 10 years of historic data should be analysed, rather than the 5 years used for most generating units.

Determining Interconnector De-Rating Factors

2.2.33 The Regulatory Authorities will supply the TSOs with the External Market De-Rating Factor for each interconnector and the planned outage and forced outage rates to be applied to the interconnector technology class.

2.2.34 The interconnectors will be an input to the TSOs De-Rating Methodology and will be treated in exactly the same way as conventional generator units. The Aggregate Import Capacity (or its proposed value for new interconnectors) of each interconnector will be used in the TSOs Methodology in lieu of the Maximum Export Capacity used for conventional generators. The planned and forced outage rates for the interconnector technology class will be used exactly as they are for any other technology class, e.g. GT-based plant, hydro plant.

2.2.35 The Regulatory Authorities will verify that the interconnectors have been correctly input to the TSOs De-Rating Methodology and that the de-rating factors have been determined in accordance with the published methodology and any associated agreed procedures.

3. DEMAND FORECASTING

3.1 OVERVIEW

3.1.1 The demand forecast used for each scenario day will be built up as follows:

- Determine the forecast peak demand for the forecast year,
- Determine a probability distribution for demand, given an input driver, based on historic data;
- Determine a forecast peak demand for the scenario day, derived from random Monte Carlo picks from the demand distribution for the relevant month;
- Determine a profile linking half-hourly demand to daily peak demand for each month;
- Generate half-hourly demand for the scenario day by applying the relevant profile to the scenario day peak demand.

3.1.2 The demand forecasts for both the I-SEM and GB will use the same principles, but the input driver to the determination of the forecast peak demand for a scenario day will be different:

- For the I-SEM, a forecast of I-SEM temperature will be the input driver. The distribution of I-SEM demand relative to a given temperature will be used to determine the scenario day value for I-SEM peak demand;
- For GB, the forecast peak demand in the I-SEM will be the input driver. The GB demand will be determined from the results of monthly linear regression analysis of the historic data.

3.1.3 The decision was taken to simulate random days for each month to allow the changing profile of solar generation across the winter to be captured.

3.2 DETERMINING FORECAST PEAK DEMAND

3.2.1 Forecast TER peak demand for the I-SEM was taken from the Generation Capacity Statement (GCS) produced by Eirgrid and SONI. The Median demand scenario was used.

3.2.2 The GCS demand forecast is for a calendar year, but the methodology requires a forecast by Capacity Year (i.e. a year starting on 1 October). For the indicative results in this appendix, the simple assumption was made that peak demand for the calendar year, Y, applies to the Capacity Year commencing in that year. It is possible that the peak demand for the Capacity Year relates to the calendar year Y+1. Absent strong demand growth, it may be difficult to be certain which calendar year will provide the peak for a Capacity Year. A conservative assumption would be to assume the greater of the forecast peak demand values for the years Y and Y+1 applies to the Capacity Year.

3.2.3 For this paper, the 2016 GCS was used. In general, the most recently published GCS at the time of the determination of De-Rating Factors should be used.

3.2.4 Forecast peak demand for GB was taken from the NGC Future Energy Scenarios for 2016. The ACS Peak Demand will be modelled for each of the four scenarios produced in National Grid's Future Energy Scenarios (FES), though it should be noted that these are very tightly clustered.

3.2.5 The FES demand forecast is currently on a calendar year basis, but the methodology requires a forecast by Capacity Year (i.e. a year starting on 1 October). For the indicative results in this appendix, the simple assumption was made that peak demand for the calendar year, Y, applies to the Capacity Year commencing in that year. It is possible that the peak demand for the Capacity Year relates to the calendar year Y+1. Absent strong demand growth, it may be difficult to be certain which calendar year will provide the peak for a Capacity Year. A conservative assumption would be to assume the greater of the forecast peak demand values for the years Y and Y+1 applies to the Capacity Year.

3.3 DETERMINING THE PROBABILITY DISTRIBUTIONS FOR DEMAND

I-SEM

3.3.1 For the I-SEM, the determination of peak demand for a scheduled day starts with a temperature forecast for the day.

3.3.2 As daily temperature is a normally distributed variable, the temperature forecast was produced by using a normal sample taken from a probability distribution derived from historic temperature data obtained from the *Met éireann* website. Winter temperature data for the thirty year period from 1986 to 2015 (inclusive) was analysed to generate the probability distribution used to produce the indicative results in this appendix. If there has been climate warming during this period, using 30 year data will at least take a prudent approach to security of supply by over-estimating the probability of a cold winter.

3.3.3 A longer period was chosen than for the correlation with SEM demand below to capture a broader range of potential weather conditions: recent years have been warm relative to longer-term history.

3.3.4 Historic, half-hourly SEM demand data was obtained for the period 1/1/2010 to 31/12/2015 from the SEM-O website and historic temperature data, maximum and minimum temperatures, were extracted from the *Met éireann* website for the same period.

3.3.5 Simple linear regression analysis was used, for winter working days only, to identify the choice of temperature data which provided the best predictor of I-SEM peak demand. Daily average temperature (taken as the mean of the maximum and minimum temperatures) provided the highest correlation. This seems reasonable given that winter peak demand tends to occur in late afternoon/early evening which tend not to be either the hottest or coldest time of the day.

3.3.6 Rather than using the demand in MW, which is subject to trend both in the historic period analysed and in the period being forecast, the demand was normalised using the annual peak demand in the regression analysis. This can then readily be used when simulating future years in conjunction with a forecast of the annual peak demand. There is a minor issue with this normalisation as each year is normalised using a different factor. This may slightly weaken the assumption that the resultant normalised demand is normally distributed, however, any deviation from the normal distribution is considered to be very small.

3.3.7 The analysis used the temperatures recorded for Dublin. Adding in temperature data for additional locations within the I-SEM into the regression did produce a modest increase in the correlation with I-SEM peak demand: e.g. addition of Malin Head for a northerly sample of temperature increased the correlation from 0.60 to 0.61. However, this is at the cost of a substantial increase in the statistical complexity required in the modelling. This was not considered worthwhile in the broader context of the methodology (and, in particular, the full range of inputs and the number simulations) and this paper is based on linear regression analysis of I-SEM demand against mean Dublin temperature.

3.3.8 For any given temperature, there is a distribution of possible demand values which could occur, as temperature only explains a proportion of the variation in demand. The standard error data from each monthly linear regression was used to simulate this additional variation.

GB

3.3.9 Historic, half-hourly GB demand data for the years 2010 to 2015 (inclusive) was obtained from the Elexon Portal website. The demand for each half hour was determined as the sum of the I1014_TSD Demand plus the NGC estimates for the production of embedded wind and solar capacity. This provides a realistic demand shape, free of distortions caused by the netting off of demand served by embedded variable capacity.

3.3.10 As for the I-SEM peak demand, rather than using the demand in MW, which is subject to trend both in the historic period analysed and in the period being forecast, the demand was normalised using the annual peak demand was used in the regression analysis. This can then readily be used when simulating future years in conjunction with a forecast of the annual peak demand.

3.3.11 Simple linear regression was used, for winter working days only, to identify the correlation between GB demand and I-SEM demand.

3.3.12 For any given value of I-SEM demand, there is a distribution of possible GB demand values which could occur, as I-SEM demand only explains a proportion of the variation in GB demand.

3.3.13 In a method analogous to that used for I-SEM peak demand, simple linear regression was used to capture the relationship between GB demand and I-SEM demand.

3.3.14 For any given temperature, there is a distribution of possible demand values which could occur, as temperature only explains a proportion of the variation in demand. The standard error data from the linear regression was used to simulate this additional variation.

3.4 DEMAND PROFILING

3.4.1 The half-hourly demand data for the SEM and GB used in section 3.3 was used to derive a typical profile for half-hourly demand for each month for the I-SEM and GB. These profiles were based on the percentage of the daily peak demand, and were an average shape for the working days in each month.

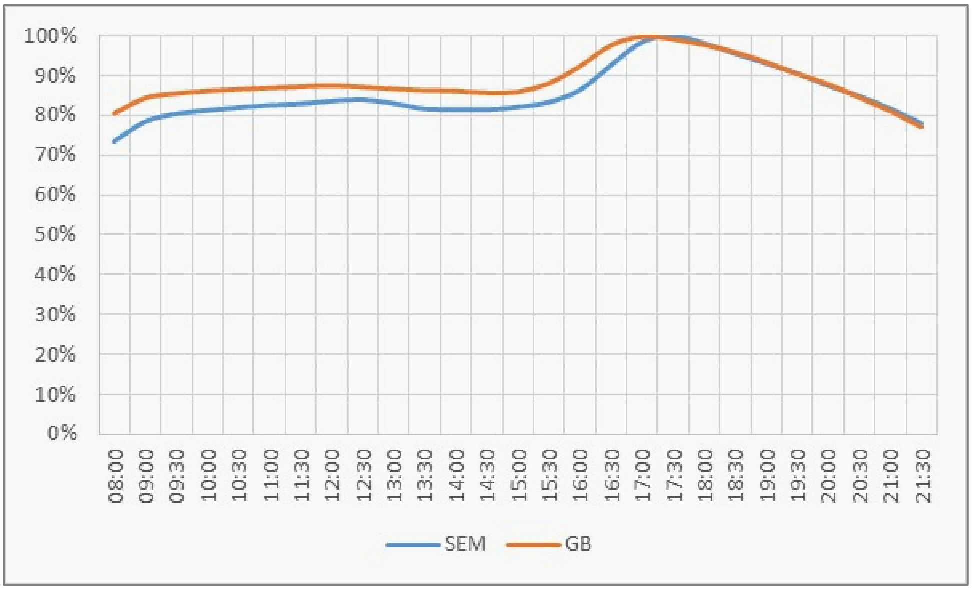

Figure 2: Demand profiles for the SEM and GB

3.4.2 The profiled demand for each half-hour period of a scenario day was derived as follows:

Profiled Demand = Forecast Annual Peak Demand (from section 3.2)

x Daily Peak Percentage (from section 3.3)

x Half-Hour Profile Percentage (from section 3.4)

3.4.3 For the analysis of scarcity set out in this paper, only the period from 08:00 to 23:00 was considered. This reflects the very low probability of scarcity outside this period and a desire to manage the computational requirements of the Monte Carlo simulation.

3.4.4 This averaging approach could be problematic if the highest demand days, and those most likely to produce scarcity, had a different demand profile from the typical working day for each month. In fact, the profiles are very similar and for every period are within 1% of each other and so an explicit sensitivity was not produced.

4. WIND FORECASTING

4.1 OVERVIEW

4.1.1 The wind forecast used for each scenario day will be built up as follows:

- The forecast, installed wind capacity for the forecast year;
- Determine a probability distribution for wind generation;
- Determine a forecast I-SEM wind generation level for the scenario day; and
- Determine a forecast GB wind generation level for the scenario day, based on the SEM wind generation level and variation around that.

4.1.2 For both the I-SEM and GB, the wind forecast covers all wind generation.

4.1.3 The wind generation level was assumed fixed for the whole of each scenario day, not profiled to the half-hourly level as was demand. This reflects the fact that there is little or no consistency of half-hourly profile for wind production in either the SEM or GB. In practise, the wind generation level in any half-hour is very highly correlated (correlation >90%) with the average wind level for the day. Whilst using a fixed wind level for the day reduces the variation which naturally exists within any given scenario day, this is compensated for by the very large number of scenario days simulated under the proposed methodology.

4.1.4 At the daily level there is reasonably strong correlation between SEM wind and GB wind production. In consequence, the level of GB wind production was forecasting taking account of SEM wind production.

4.1.5 Analysis for both the SEM and GB made clear that there is very low correlation between temperature or demand and wind generation. This was true when considering either daily data or half-hourly data. Clearly there is a degree of seasonal correlation as both demand and wind are generally higher in the winter, but this was captured by simulating for the winter period only. However, there is a clear effect in the days of highest peak demand whereby wind is lower than would be expected on a typical winter day. This effect was included in the modelling, with a reduction in the simulated wind capacity on the days with the highest demand.

4.2 FORECASTING INSTALLED WIND CAPACITY

4.2.1 For the I-SEM, the total forecast installed wind capacity was taken from the GCS published by Eirgrid and SONI. All wind, large and small, in both the RoI and NI was included.

4.2.2 For this paper, the 2016 GCS was used. In general, the most recently published GCS at the time of the determination of De-Rating Factors should be used.

4.2.3 For GB, the total of the forecast on- and off-shore wind was taken from each of the four scenarios of the FES produced by National Grid and a separate set of indicative results is shown for each in section 10.

4.2.4 For this paper, the 2016 FES was used. In general, the most recently published FES at the time of the determination of De-Rating Factors should be used.

4.3 THE PROBABILITY DISTRIBUTION FOR I-SEM WIND

4.3.1 Wind generation is not a normally (or even log-normally) distributed variable. As a consequence, a manual distribution for I-SEM wind generation was produced using a histogram-based approach.

4.3.2 As for the demand, rather than using the wind production in MWh, which is subject to trend both in the historic period analysed and in the period being forecast, the percentage of installed capacity was used in the histogram analysis. This can then readily be used when simulating future years in conjunction with a forecast of the installed wind capacity.

4.3.3 For the purposes of this paper, a fairly coarse histogram was used. The wind production was split into 'bins' representing 2.5% of installed capacity, i.e. at 0%, 2.5%, 5%, …, 97.5%, 100%.

4.3.4 Clearly, a more granular approach could be utilised but the bin size chosen was felt to provide a sensible balance given the volume of historic data available and the number of scenario days to be simulated.

4.3.5 On-shore and Off-shore wind were considered in total. A refinement to the approach would consider them separately as they are likely to have somewhat different distributions. This approach was not taken given the rather limited availability of historic off-shore wind data and the fact that much of that which exists will cover the early years of operation, which may not be indicative of long-term performance. In the longer-term, as data availability improves, it may be worth considering creating separate forecasts for on-shore and off-shore wind production.

4.3.6 The histogram analysis used half-hourly data for the years 2010 to 2015 (inclusive) for the winter months only, with the values aggregated to be produce average daily wind production levels. All days were analysed as there is no reason to believe that wind is affected by working or non-working days and use of all days increased the sample size being analysed.

4.3.7 SEM wind data was obtained from SEMO.

4.3.8 There is a tendency for I-SEM wind generation to be lower at times of highest demand. Where the daily peak demand is below 90% of the annual peak demand, the average wind production is 32% of installed capacity, but as peak demand rises this falls to only 15% of installed capacity above 98% of annual peak demand. The impact of this effect is included in the analysis, the results of which are given in section 10.

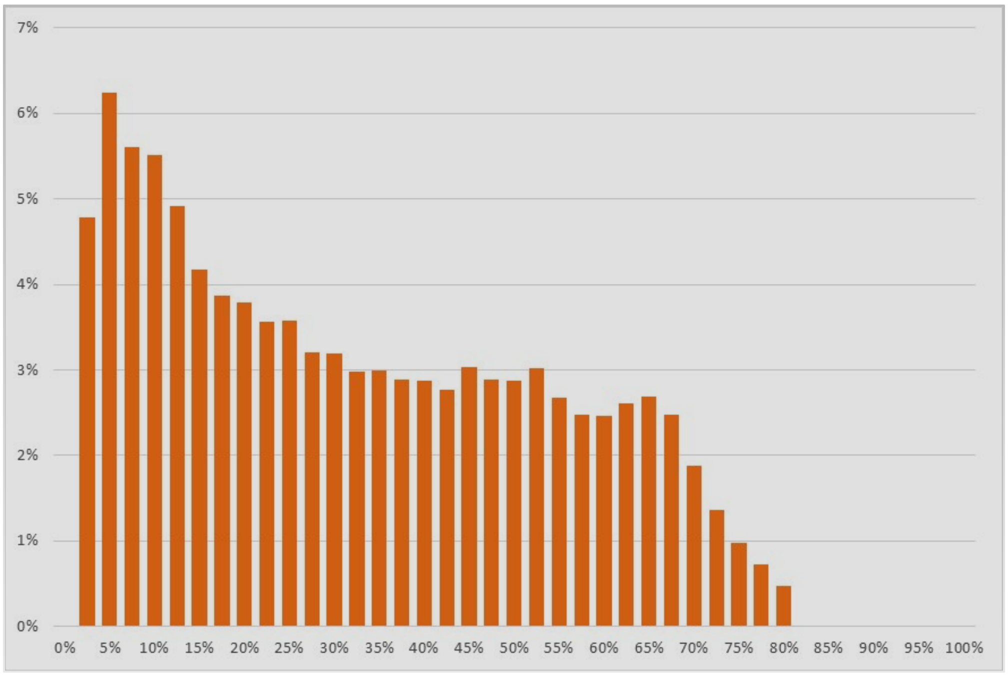

Figure 3: Frequency histogram for wind in the SEM

4.4 DETERMINING THE WIND FORECAST GENERATION LEVEL

I-SEM

4.4.1 A simple random number between 0 and 1 was used to look-up the corresponding production level from the wind probability distributions (Note: a cumulative frequency distribution was used for this look-up). This generates the percentage of installed capacity which the wind production represents.

4.4.2 The forecast wind generation for a schedule day was the product of the forecast installed capacity and the sampled generation percentage determined under paragraph 4.4.1.

GB

4.4.3 The average daily wind production for GB is correlated with that for the SEM, and in a determination of coincident scarcity it is important to capture this link.

4.4.4 Linear regression was used to determine the portion of the GB wind production explained by SEM wind production and the standard error for the unexplained portion. The slope and intercept from this regression, plus the standard error were then used to determine a forecast of GB wind production.

4.4.5 This forecast relies on the standard errors being normally distributed to generate a distribution of wind values. This is not strictly true, though the distribution is close and the greatest variance from normality occurs at times of high wind production – and so is not an issue for this analysis.

5. SOLAR PROFILES

5.1 SOLAR PROFILES

5.1.1 For GB, the volume of installed solar generation is significant and so its impact needs to be incorporated into the methodology. The contribution of solar capacity cannot be ignored as while it provides little or no contribution at winter peak, it can contribute more significant capacity in the shoulder periods around the peak and in months like October and March where the day length is increased.

5.1.2 Half-hourly production from embedded solar generation is estimated by NGC and published through the Elexon Portal. The same report also includes the installed solar capacity in each period.

5.1.3 This historic half-hourly data, converted into load factors, was taken for the period from 2010 to 2016 and averaged to produce typical monthly profiles for solar production.

5.1.4 These monthly profiles were then applied to the forecast installed solar capacity given in the NGC FES scenarios to obtain an estimate of the contribution to serving GB demand from solar capacity. Example profiles are shown in Figure 4.

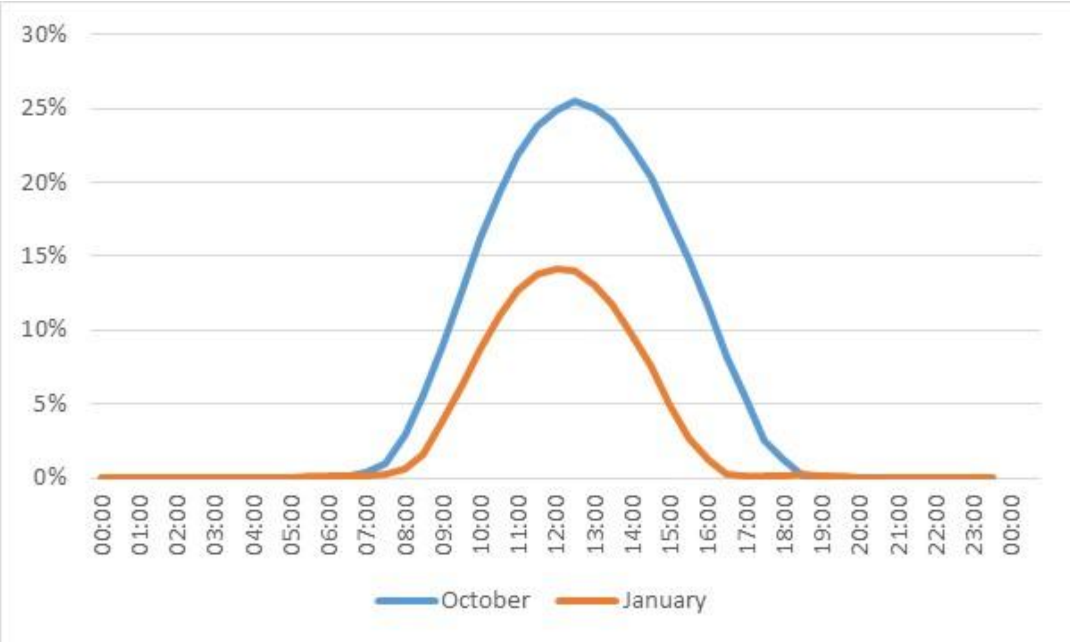

Figure 4: Sample GB solar profiles (load factor)

6. OPERATIONAL RESERVE REQUIREMENTS

6.1 I-SEM

6.1.1 For the SEM, the operational reserve requirement is set on the basis of the Largest Single Infeed (LSI). This has historically used a CCGT of 444MW, rather than EWIC which is a 500MW infeed.

6.1.2 Discussion with the TSOs suggested that a value of 100% of LSI should be used.

6.1.3 Whilst LSI will change from period to period, there is a cluster of plant with sizes around 400-500MW which are likely to dominate at times of possible scarcity.

6.1.4 For this appendix, a value of 450MW was used to represent the operational reserve requirement when determining the indicative results. This implicitly assumes that the value of operational reserve requirement will not change in the forecast period. This seems reasonable given the changes in the generation portfolio set out in the 2016 GCS, which give no reason to believe there should be major changes in the value of LSI. A more conservative assumption would be to use 500MW (representing EWIC as the LSI) and this will be used for the final determination of the de-rating for interconnectors.

6.2 GB

6.2.1 For GB, historic operational reserve requirements were taken from the Operating Margin (OPMR) log published on the National Grid website.

6.2.2 Only rather limited history of the OPMR was available, covering the period from 2 February 2015 to 3 May 2016. The latest OPMR value published for each day was used.

6.2.3 The operational reserve requirement reported in the OPMR log is made up of several components. Most of these are broadly constant and an average historic value for these items was used. Two inputs, covering capacity unavailable, were highly variable. These values covered commissioning plant and non-firm transmission capacity. Only the fixed component was used in the analysis.

6.2.4 The forecast operational reserve requirement was taken as the average the relatively fixed component yielding an estimate of around 3.6GW.

6.2.5 There is an implicit assumption that the GB operational reserve requirement seen in the rather short historic period analysed are sensible as predictors of future reserve levels. It is possible that with the ending of the Supplemental Balancing Reserve and implementation of the GB capacity market that operational requirements may change. The assumptions will be reviewed as more data becomes available and the methodology adjusted, if necessary.

7. OTHER SCENARIO INPUTS

7.1 OVERVIEW

7.1.1 In addition to the data inputs already mentioned above, a number of other non-stochastic inputs are needed to determine scarcity in the I-SEM and GB:

- Available I-SEM capacity
- Available GB capacity

7.1.2 In each case, available capacity is determined before outages are taken into account.

7.1.3 As explained below, very different approaches were taken to the determination of available capacity in the I-SEM and GB.

7.2 AVAILABLE GB CAPACITY

7.2.1 The portfolio was taken for each of the scenarios in the FES published by National Grid. The available capacity included capacity from the non-SEM interconnectors.

7.2.2 The different scenarios have different assumptions on the timing of new interconnection to GB. In general, the most recently published FES at the time of the determination of De-Rating Factors should be used.

7.2.3 Inclusion of the capacity of interconnectors to GB in the determination of available capacity is on the basis that scarcity in any market relies on a perfect storm of high demand, low variable generation and high outage levels of conventional plant. Whilst there is some correlation for demand and variable generation between GB, the SEM and continental Europe, geographical diversification means that this is relatively low. To account for the inability of GB to import from continental Europe at times of scarcity, the de-rating factors applied by GB in their capacity market were applied to the interconnector capacities when determining available GB capacity.

7.2.4 For this paper, the letter published by DECC on 8 July 2016 was used to obtain de-rating factors for the GB interconnectors. In general, the most recent values published by DECC for the relevant year should be used. For the unnamed additional interconnections in the FES for which DECC has not published a de-rated factor, a value of 70% was used.

7.2.5 All capacity except for wind and solar was summed to calculate the Available GB Capacity. For GB, as is explained in section 8 below, wind and solar were netted from demand.

7.2.6 The value of External Market De-rating Factor for GB, as shown in section 10, is very sensitive to the available GB capacity and the generation mix. In particular, different years and the different FES scenarios produce a wide range of values. Higher rates of closure and a generation mix with more variable and less conventional generation make scarcity much more likely in GB and this impacts the effectiveness of the interconnectors as a source of capacity to the I-SEM.

7.3 AVAILABLE I-SEM CAPACITY

7.3.1 A very similar approach to the determination of available capacity in the I-SEM could have been taken as was used in GB. However, given that the I-SEM market design is substantially different to the SEM design to which any historic data relate an alternative approach was taken based on the capacity being procured under the CRM and the security of supply standard for the I-SEM. This provides a higher frequency of potential scarcity allowing the analysis to proceed and reflect the long-term position which the CRM might be expected to achieve.

7.3.2 Ideally, the available I-SEM capacity would be based on the Capacity Requirement determined for the relevant forecast year. However, the External Market De-rating Factor and interconnector outage rates are an input to this calculation and so an estimate will be used.

7.3.3 To convert the Capacity Requirement to the available I-SEM capacity, it needs to be uprated to account for the average de-rating factor applied. This will use an estimated value based on previous average de-rating factors obtained from the general de-rating methodology analysis.

7.3.4 As with GB, the expected contribution from wind is netted off the available I-SEM capacity. The actual contribution of wind within the Capacity Requirement is an output of the overall de-rating methodology. To enable this analysis to proceed, the Wind Capacity Credit from the GCS was used as a proxy for the value. Based on the TSOs' work to-date on the full de-rating methodology, this seems likely to be close to the actual value.

8. DETERMINING EFFECTIVE CAPACITY

8.1 OVERVIEW

8.1.1 For each of the I-SEM and GB, the net available capacity is determined as set out in section 7, i.e. how much conventional capacity exists to meet the demand and reserve requirement in a given simulated half-hour.

8.1.2 A probability distribution is generated for each of the I-SEM and GB which describes the frequency with which a given number of simultaneous outages may occur. As described below, this probability distribution was produced based on the conventional generation portfolio and some simplifying assumptions to make the statistical analysis tractable.

8.1.3 The forecast need for net capacity in the I-SEM and GB is determined in each half-hour, as forecast demand + forecast operational reserve requirement – forecast wind production – forecast solar production.

8.1.4 Given the forecast surplus (or shortfall) of available capacity in each market against the need, the relevant probability distribution is used to determine the probability of coincident outages of conventional plant causing the market to experience scarcity. Obviously, if there is a forecast shortfall then there is a 100% probability of scarcity, whatever outages may occur.

8.1.5 This yields, for each of the simulated half hours (08:00 to 23:00) on each simulated day, a probability of scarcity arising endogenously in each of the I-SEM, $\mathbf{p(S_{end})}$**,** and GB, $\mathbf{p(G)}$.

8.1.6 In addition, there is a probability that scarcity in the I-SEM could be caused by scarcity in GB, with higher GB prices switching the interconnectors to export. This was modelled exactly as for p($\mathbf{S}_{end}$) but with 950MW[2] of available capacity removed from the I-SEM, a conservative assumption that both interconnectors would be exporting at full capacity. This generates the probability of scarcity in the I-SEM given scarcity in GB: $\mathbf{p(S_{end}|G)}$.

8.1.7 The probability of coincident scarcity in a half-hour is then the product of the probability of scarcity in the I-SEM given scarcity in GB and the probability of scarcity in GB, i.e.

$$\mathbf{p(S_{end} \cap G) = p(S_{end}|G) \times p(G)}.$$

8.1.8 If scarcity in GB can cause scarcity in the I-SEM, we need to determine the total probability of scarcity occurring in the I-SEM. This can be determined as:

$$\mathbf{p(S_{tot}) = p(S_{end}) + [1 - p(S_{end})] \times p(S_{end} \cap G)}$$

8.1.9 By summing across all of the half-hours in all the scenario days, we can discover the expected number of half-hours in which scarcity will occur in the I-SEM, p(S_{tot}) and that coincident

[2] It is assumed that at times of scarcity in GB, the 80MW export constraint on the Moyle interconnector would no longer be binding, given the low GB wind production likely at such times. However, a scenario was run with this constrains in place.

scarcity will occur in both the I-SEM and GB, $p(S_{end} \cap G)$. The ratio of these two quantities gives the expected frequency that the I-SEM will have scarcity and will be unable to import capacity from GB as it is also in scarcity, **p(interconnector capacity ineffective)**.

8.1.10 The External Market De-rating Factor can then be determined as **1- p(interconnector capacity ineffective).**

8.2 COINCIDENT OUTAGE PROBABILITY DISTRIBUTION

8.2.1 Each market is comprised of many plants, all of different sizes and with different outage rates. It is very difficult computationally to determine the true probability distributions for such a system and so a simplified system has been modelled.

8.2.2 The simplified model used the actual generation stack for the I-SEM and GB, but used a fixed outage rate for all units. The value for typical unplanned outages reported by Eurelectric in its document "Power Statistics and Trends 2011" was used, in line with the LOLP analysis performed for CRM1. This report shows an average value of 7%. It would be possible to obtain reliable outage rates for each individual unit in I-SEM and GB and to perform a similar analysis on that basis. It also would be possible to produce a sensitivity using a different average outage rate.

8.2.3 There is no formulaic way to produce a probability distribution for such a model, and so Monte Carlo simulation of outages was used to determine the probability of various levels of outage occurring. For this analysis, 100,000 trials for the total portfolio in each of I-SEM and GB were found to produce a stable distribution. The results of the trials were converted into probability distributions using histogram analysis. For I-SEM, this analysis was based on 200MW "bins" and for GB on 500 MW "bins".

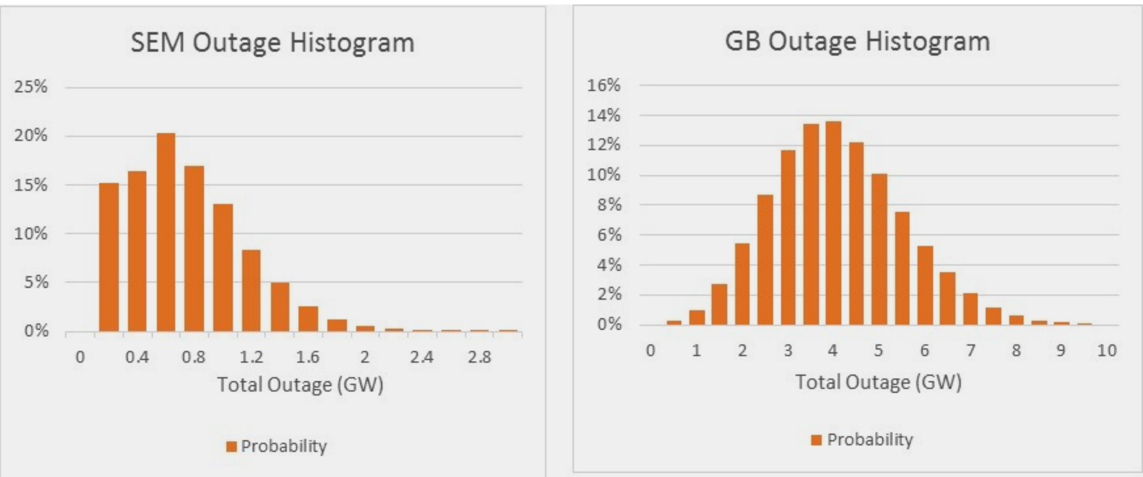

Figure 5: Outage Histograms for the SEM and GB

9. INTERCONNECTOR TECHNICAL AVAILABILITY

9.1 INTERCONNECTOR TECHNICAL AVAILABILITY

9.1.1 Wherever possible, the technical availability of the interconnectors will be treated in the same way in the de-rating process as for technical availability of conventional generation capacity.

9.1.2 The interconnectors will be placed into a separate Technology Class, "Interconnectors", which will be the direct analogue of the Technology Classes used to de-rate conventional generation capacity, e.g. GT-based, ST-based, hydro, pumped storage.

9.1.3 This approach requires a Forced Outage Rate and Scheduled Outage Rate to be calculated for the Technology Class. As for other technology classes, a run-hours weighted average of the interconnectors in the Technology Class will be used.

9.1.4 Outage data for Moyle and EWIC was obtained from the Eirgrid/SONI Operational outage data produced by the TSOs. This covered the years 2006 to 2015 (inclusive).

9.1.5 There are some issues which arise from the very small number of interconnectors in the Technology Class which call for some change in approach for this paper:

- Moyle had a long term outage running from the spring of 2013 until later 2015.
- EWIC has only been commissioned since May 2013.

9.1.6 To ameliorate these effects, the historic analysis will cover the 10 most recent years for which data is available.

9.1.7 The use of running-hours weighting on a year-by-year basis to form the average outage rates is then impractical given the limited overlap of the two interconnectors and the potential for an atypical outage pattern on EWIC to skew the results. The outage factors were weighted by the overall running hours of each interconnector.

9.1.8 Indicative analysis based on data from 1 April 2006 until the end of 2015 yields the following outage rates for the Interconnector Technology Class:

Data Source	***Moyle***		***EWIC***		***Interconnectors***	
	FOR	***SOR***	***FOR***	***SOR***	***FOR***	***SOR***
TSOs Operations data	6.3%	1.2%	1.2%	3.3%	5.1%	2.1%

9.1.9 It should be noted that given its current outage, the EWIC forced outage rate will rise significantly in the final determination of outage rates for the first transitional auction. This will also increase the forced outage rate applied to the whole interconnector technology class to a value likely to be broadly consistent with the 6% value ENTSO-E assumed for HVDC interconnectors in its Mid-Term Adequacy Forecast methodology consultation.

9.1.10 These rates for the Interconnector Technology Class will be used in the TSOs De-Rating Methodology along with the Aggregate Import Capacity for each of the interconnectors.

10. INDICATIVE RESULTS

10.1 RESULTS

10.1.1 The de-rated capacity for an interconnector is determined as follows:

- The Effective Interconnector Capacity is the product of the Aggregate Import Capacity and the External Market De-rating Factor.
- The de-rating curves for the interconnector technology class, which capture the impact of outages and unit size, will be determined using the TSO de-rating methodology. This methodology takes the outage characteristics of the interconnector technology class and considers a range of values for Aggregate Import Capacity.
- The de-rated capacity for the interconnector is the product of the Effective Interconnector Capacity and the relevant de-rating curve given the size of the interconnector.
- The de-rating factor for an interconnector is then the ratio of its de-rated capacity to its Aggregate Import Capacity.

10.1.2 This appendix was developed in parallel with the TSOs appendix setting out the broader methodology for determining the Capacity Requirement and De-Rating Factors. New indicative results were not generated based on the relatively modest changes to the general methodology set out in Appendix 1 and so the estimate for the Capacity Requirement and the average level of de-rating used in this analysis were based on the indicative results contained in Appendix 1 of the consultation paper.

10.1.3 The results given in this section, which are based on the revised inputs and methodology set out in this Appendix, should be considered *Indicative* only.

10.1.4 Each of the four FES scenarios was run, as were cases assuming an export constraint on the Moyle interconnector and at different levels of assumed capacity in the I-SEM.

10.1.5 The scenarios were run for each of the calendar years 2017 to 2021. The External Market De-rating Factors for each scenario are given in the tables below:

Scenario	***2017***	***2018***	***2019***	***2020***	***2021***
SEM Capacity = 8231MW, GB imports 950MW during scarcity					
GB: Gone Green	45%	35%	21%	14%	17%
GB: Slow Progression	77%	64%	47%	34%	38%
GB: No Progression	92%	84%	92%	55%	61%
GB: Consumer Power	84%	59%	50%	39%	42%
SEM Capacity = 8231MW, GB imports 580MW during scarcity					
GB: Slow progression	88%	79%	63%	53%	57%
GB: Slow Progression, GB Imports					

950MW during scarcity					
SEM Capacity = 8500MW	62%	48%	30%	21%	24%

10.1.6 The same Forced and Scheduled Outage Rates were applied to all four Capacity Years, these values are:

Data Source	***Interconnectors***	
	FOR	***SOR***
TSOs Operations data	5.6%	2.3%

10.1.7 The de-rating factor for an interconnector, which is the ratio of its de-rated capacity to its Aggregate Import Capacity, is set out in the table below. NB: this table was determined using the outage-based de-rating factors and the "nameplate" capacity associated with the capacity requirement of 7498MW from the consultation paper, i.e. 8231MW.

Scenario	***2017***	***2018***	***2019***	***2020***	***2021***
SEM Capacity = 8231MW, GB imports 950MW during scarcity					
GB: Gone Green	38%	30%	18%	12%	14%
GB: Slow Progression	65%	54%	40%	29%	32%
GB: No Progression	78%	71%	78%	47%	52%
GB: Consumer Power	71%	50%	43%	33%	36%
SEM Capacity = 8231MW, GB imports 580MW during scarcity					
GB: Slow progression	75%	67%	54%	45%	48%
GB: Slow Progression, GB Imports 950MW during scarcity					
SEM Capacity = 8500MW	53%	41%	26%	18%	20%
SEM Capacity = 9000MW	30%	19%	11%	8%	9%

10.1.8 Based on the range of scenarios run and likely outcomes in each external market, the RAs will identify an External Market De-rating Factor. This will be used in conjunction with the de-rating curves produced by the TSO methodology to set the de-rated capacity for each interconnector.

10.1.9 On the basis of these indicative results, and given the most probably outcomes in GB in the period out to 2021, the interconnector de-rating would be based on the No Progression scenario for GB with full exports over Moyle and the Slow Progression scenario for GB with limited exports over Moyle. This would produce an indicative interconnector de-rating factor of 50%.