ESP Consulting

PREPARED FOR:

# CRM Consultation

## Interconnector De-rating Methodology

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# Table of Contents

# 1. Introduction

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 "**Operational Reserve Requirements**" details the reserve scenarios considered by the methodology.
- Section 6 "**Other Scenario Inputs**" details the other inputs used to generate scenarios considered by the methodology.
- Section 7 "**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 8 "**Interconnector Technical Availability**" details the analysis of historic planned and forced outages rates on the existing interconnectors.
- Section 9 "**Results and Conclusions**" details the results of the analysis, sensitivity analyses performed 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.

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 sought which used historic data unaffected by the changes to the I-SEM market design or the changes in GB. This focused on the use of historic temperature, demand, wind and outage data. This historic data was 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 Parameters Consultation process which has not yet been published. 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 may exist if the price in GB rises above the Reliability Option (RO) strike price in the I-SEM. Given the level proposed for the I-SEM strike price, it is only anticipated that this would occur in the intraday or balancing markets. Under these circumstances, the price for the I-SEM trade could be set above the RO strike price if an I-SEM supplier trades with a high-priced GB unit or the TSOs take a balancing market action from a high-priced GB unit (and this causes the Imbalance Price to be above the RO strike price). Such events are considered to be extremely rare, particularly in the early life of the I-SEM.

2.1.10 If such an event occurs and an interconnector is exporting at the time, it could be considered that it is not contributing to the hedge to suppliers which its RO represents and that this fact should be taken into account when setting the de-rating factor for the interconnector. Consideration of this issue needs to take account of the fact that the interim solution for cross-border participation in the CRM is availability-based i.e. does not consider direction of metered interconnector flow at all.

2.1.11 Given the above, the RAs do not intend reducing the de-rating factor for the interconnectors to try and capture those rare events where a GB unit, priced above the RO strike price, sets the price for an I-SEM trade at a time when the interconnector is exporting. 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 simulated 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 simulated winter working day uses six 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.

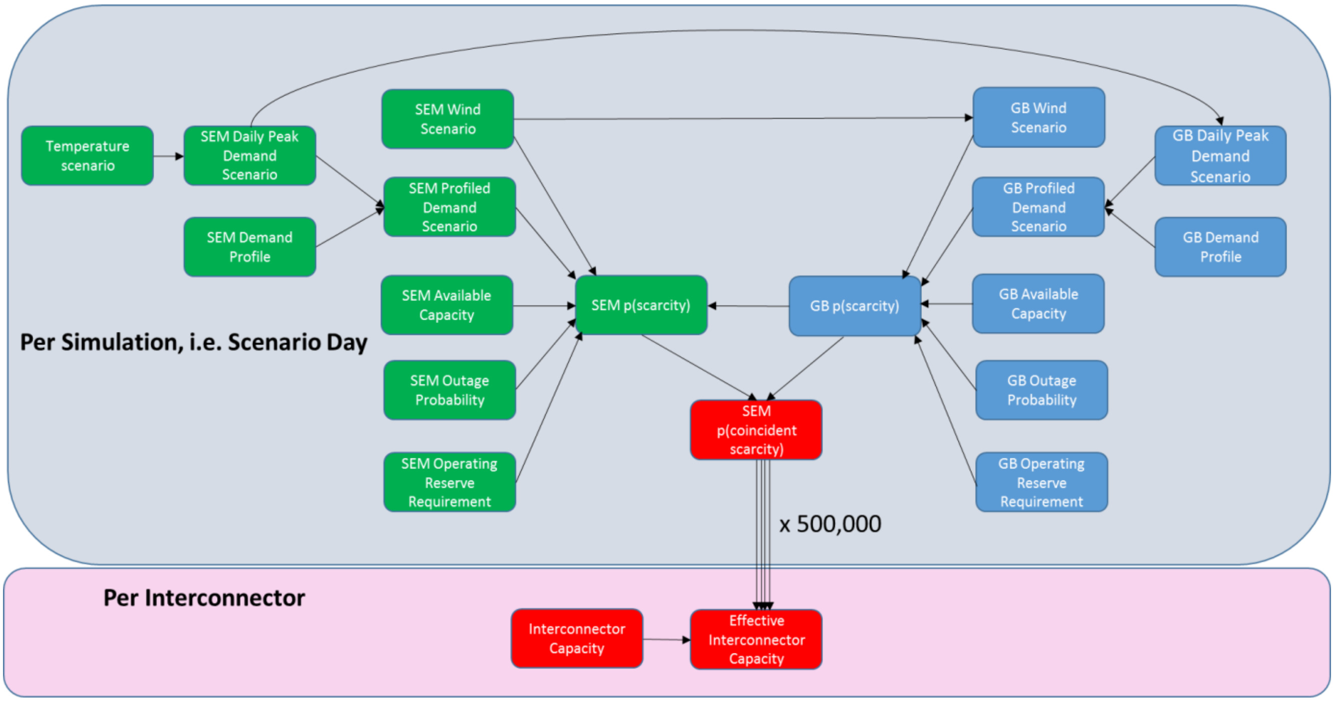


Figure 1: Simplified Methodology Overview

### *Deriving the Probability of Scarcity in the I-SEM*

2.2.7 The methodology starts with a forecast of the mean temperature for the I-SEM for each scenario day. This is a Monte Carlo pick taken from a distribution of winter temperatures based on historic weather data.

2.2.8 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.

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

2.2.10 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.

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

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

2.2.13 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*

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

2.2.15 As GB peak demand is strongly correlated to I-SEM peak demand, 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, allowing for the historic distribution of GB peak demand for any given value of I-SEM peak demand.

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

2.2.17 A Monte Carlo pick is used to pick a level of GB wind generation for the scenario day (**$GW_d$**), accounting for the correlation at the daily level between I-SEM and GB wind production. This pick is taken from a distribution of GB wind output derived from historic production data.

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

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

2.2.20 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: $GC – (GD_b + GR – GW_d)$
- 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 Effective Capacity of an Interconnector*

2.2.21 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 $\mathbf{p(S_{end}|G)}$.

2.2.22 Then the probability of coincident scarcity is given as:

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

2.2.23 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 $\mathbf{p(S_{tot})}$.

2.2.24 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:

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

2.2.25 From the value p(Capacity unavailable when needed), an Effective Capacity for an interconnector can be derived. This will be:

NTC x [1 - p(Capacity unavailable when needed)]

where NTC is the Net Transfer Capacity available for import.

### *Determining Interconnector Technical Availability*

2.2.26 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.

2.2.27 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 TSO 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.

2.2.28 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.

### *Determining Interconnector De-Rating Factors*

2.2.29 The Regulatory Authorities will supply the TSOs with the Effective Capacity for each interconnector and the planned outage and forced outage rates to be applied to the interconnector technology class.

2.2.30 The interconnectors will be an input to the TSO De-Rating Methodology and will be treated in exactly the same way as conventional generator units. The Effective Capacity of each interconnector will be used in the TSO 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.

2.2.31 The Regulatory Authorities will verify that the interconnectors have been correctly input to the TSO 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;
- Determine a profile linking half-hourly demand to daily peak demand;
- Generate half-hourly demand for the scenario day by applying the 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 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. This distribution of GB demand relative to a given value of I-SEM demand will be used to determine the scenario day value of GB peak demand.

3.1.3 The decision was taken to simulate random winter days, rather than random days for each winter month. This was because multi-variate regression analysis of month, temperature and I-SEM peak demand showed that the month tends to dominate the temperature variable in explaining the level of peak demand for some months. This would have created very little variation in peak demand for these months, defeating the purpose of running multiple Monte Carlo simulations. This decision for demand, forces the rest of the analysis to also simulate on the basis of winter days, rather than on a monthly basis.

## 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 this paper, 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. The analysis could use the peak from year Y, or Y+1, or choose the year most likely to contain the peak based on historical analysis, or consider the maximum peak demand from the two years.

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 National Grid Electricity Ten Year Statement (ETYS), "peak Active ACS unrestricted National Demand". The [Slow Progression] scenario was used. While there are four scenarios produced in National Grid's Future Energy Scenarios (FES) and covered in the ETYS, for the period covered by the determination of de-rating factors these are generally very tightly clustered.

3.2.5 The ETYS was selected in preference to the FES document itself as the ETYS shows demand on a grid-basis, rather than total demand. This choice was driven by the need to produce a consistent dataset with available GB data for half-hourly demand, wind capacity and the generation portfolio. Use of total demand creates a number of issues relating to the treatment of distribution connected capacity, particularly in the analysis of historic data which was needed to produce the probability distributions used by the Monte Carlo simulations which underpin the methodology.

3.2.6 The ETYS demand forecast is for a year commencing on 1 April, but the methodology requires a forecast by Capacity Year (i.e. a year starting on 1 October). For this paper, the simple assumption was made that peak demand for the ETYS year, Y/Y+1, applies to the Capacity Year, Y+1/Y+2, given that the two years share the same winter.

3.2.7 For this paper, the 2015 ETYS was used, and the data was estimated from Figure 2.2. In general, the most recently published ETYS at the time of the determination of De-Rating Factors should be used. Some care will be needed to ensure that the definition of demand is consistent with the historic data used to produce the probability distributions and with the wind and generation data being used for GB.

## 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. 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 This analysis produced a mean (mean) temperature of 9.6˚C with a standard deviation of 4.4˚C. 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, e.g. the requirement to use Cholesky decomposition of the variance-co-variance matrix. This was not considered worthwhile in the broader context of the methodology[2] (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.

3.3.9 As both temperature and electricity demand are normally distributed, bivariate normal sampling was used to determine the I-SEM forecast peak demand. This process requires the following inputs:

- A normally distributed random seed for temperature with mean = 0 and standard deviation =1 ($\mathbf{z_T}$)
- A normally distributed random seed for demand with mean = 0 and standard deviation =1 ($\mathbf{z_D}$)
- The mean and standard distribution for temperature ($\boldsymbol{\mu_T}$ and $\boldsymbol{\sigma_T}$);
- The mean and standard distribution for demand ($\boldsymbol{\mu_D}$ and $\boldsymbol{\sigma_D}$);
- The correlation between temperature and demand ($\boldsymbol{\rho}$).

3.3.10 These statistics were computed using the SEM demand and Dublin mean temperature data for the winter, working days for the years 2010 and 2015 (inclusive).

[2] i.e. the requirement to use Cholesky decomposition of the variance-co-variance matrix.

3.3.11 The random sample for I-SEM Peak Demand is then determined as:

$\mu_D + \sigma_D (z_T \times \rho + z_D \times \text{SQRT}(1 - \rho^2))$

3.3.12 The statistical parameters used for the bivariate normal sample described in 3.3.9 above were:

**Temperature (Dublin mean):** $\boldsymbol{\mu_T}$ = 9.7 and $\boldsymbol{\sigma_T}$ = 3.1

**Demand (as percentage of annual peak):** $\boldsymbol{\mu_D}$ = 0.88 and $\boldsymbol{\sigma_D}$ = 0.06

**Correlation:** $\boldsymbol{\rho}$ = -0.60

***GB***

3.3.13 Historic, half-hourly GB demand data for the years 2010 to 2015 (inclusive) was obtained from the Elexon Portal website. This data is consistent with the ETYS demand forecast data used in paragraph 3.2.4.

3.3.14 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.

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

3.3.16 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.

3.3.17 In a method analogous to that used for I-SEM peak demand, bivariate normal sampling was used to determine the GB demand for a given value of I-SEM demand. This process requires the following inputs:

- A normally distributed random seed for I-SEM demand with mean = 0 and standard deviation =1 ($\mathbf{z_{SEM}}$)
- A normally distributed random seed for GB demand with mean = 0 and standard deviation =1 ($\mathbf{z_{GB}}$)
- The mean and standard distribution for I-SEM demand ($\boldsymbol{\mu_{SEM}}$ and $\boldsymbol{\sigma_{SEM}}$);
- The mean and standard distribution for GB demand ($\boldsymbol{\mu_{GB}}$ and $\boldsymbol{\sigma_{GB}}$);
- The correlation between I-SEM and GB demand ($\boldsymbol{\rho}$).

3.3.18 The random sample for GB peak demand is then determined using an equation analogous to that shown in paragraph 3.3.11.

3.3.19 The statistical parameters used for the bivariate normal sample described in 3.3.9 above were:

**SEM demand (as percentage of annual peak):** $\boldsymbol{\mu_{SEM}}$ = 0.77 and $\boldsymbol{\sigma_{SEM}}$ = 0.07

**GB peak (as percentage of annual peak):** $\mu_{GB}$ = 0.81 and $\sigma_{GB}$ = 0.08

**Correlation:** $\rho$ = 0.77

## 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 of the I-SEM and GB. These profiles were based on the percentage of the daily peak demand, and were an average shape for winter working days.


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 winter, working day. 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 the I-SEM, the wind forecast covers all wind generation. However, for GB the wind forecast only covers the wind which serves the ETYS demand set out in paragraph 3.2.4. This reflects limitations in the availability of historic and forecast wind and demand data for GB.

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.

## 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 transmission-connected on- and off-shore wind was taken from the Slow Progression scenario of the FES produced by National Grid. While there are four scenarios produced in the FES, for the period covered by the determination of de-rating factors these are generally very tightly clustered.

4.2.4 For this paper, the 2015 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 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 5% of installed capacity, i.e. at 0%, 5%, 10%, …, 95%, 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 explored in a sensitivity, the results of which are given in section 9.

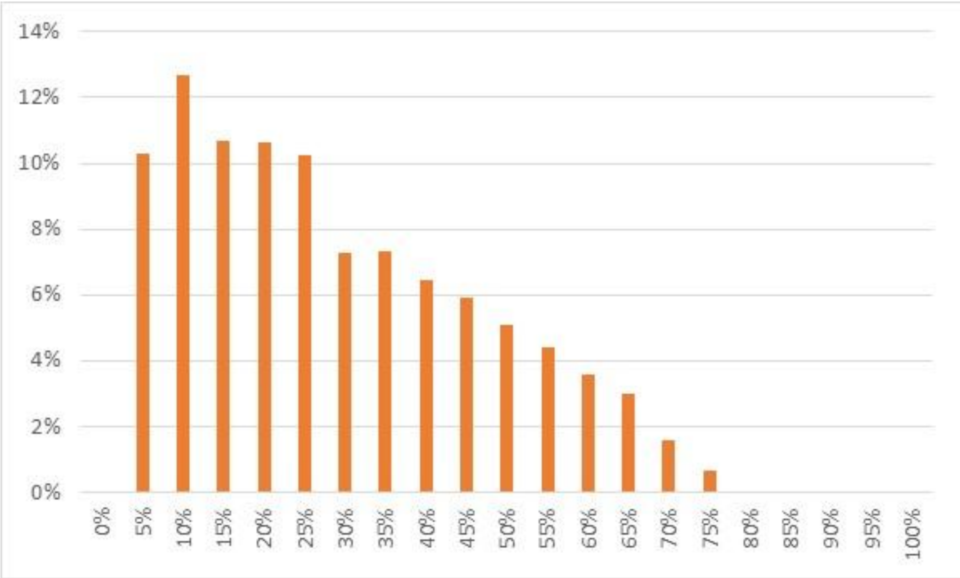


Figure 3: Frequency histogram for wind in the SEM

## 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 The statistical parameters for determining GB wind production from the SEM wind were:

| ***Variable*** | ***Value*** | ***Standard Error*** |
|---|---|---|
| Intercept | 8.6% | 1.0% |
| Slope | 77.2% | 8.6% |

4.4.6 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. Operational Reserve Requirements

## 5.1 I-SEM

5.1.1 For the SEM, the operational reserve requirement is set on the basis of the Largest Single Infeed (LSI).

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

5.1.3 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.

5.1.4 For this paper, a value of 450MW was used to represent the operational reserve requirement in the I-SEM. 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.

## 5.2 GB

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

5.2.2 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.

5.2.3 The operational reserve requirement reported in the OPMR log is made up of several components. Many of these are broadly constant and an average historic value for these items was used. Two inputs, covering capacity unavailable, were highly variable with no clear correlation to any known driver. For the total of these values, a manual distribution was produced using a histogram approach. Ten bins were used for the histogram analysis.

5.2.4 The forecast operational reserve requirement was taken as the sum of the relatively fixed component and the randomly sampled value for unavailable capacity. The fixed component average around 3.6GW with the more variable component moving between 0MW and 5.5GW.

5.2.5 There is an implicit assumption that the fixed and variable portions of the GB operational reserve requirement seen in the rather short historic period analysed are sensible as predictors of future reserve levels. The historic data analysed did have a very wide range of operational reserve requirements and such a range may not be more broadly representative. This should be reviewed as more data becomes available and the methodology adjusted, if necessary.

# 6. Other Scenario Inputs

## 6.1 Overview

6.1.1 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

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

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

## 6.2 Available GB Capacity

6.2.1 Consistent with the approach taken to demand and wind for GB, the GB available capacity was based on the transmission connected generation portfolio.

6.2.2 The portfolio was taken from the FES published by National Grid and from the Slow Progression scenario. The available capacity included capacity from the non-SEM interconnectors.

6.2.3 For this paper, the 2015 FES was used which includes an assumption that the NEMO Link and Eleclink interconnectors come on line in 2019/20. In general, the most recently published FES at the time of the determination of De-Rating Factors should be used.

6.2.4 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.

6.2.5 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.

6.2.6 All non-wind, capacity was summed to calculate the Available GB Capacity. For GB, as is explained in section 7 below, wind was netted from demand.

6.2.7 The value of effective interconnector capacity, as shown in section 9, is very sensitive to the available GB capacity. In particular, the scenarios considered in the FES show significant differences in the rate of closure of coal capacity in the period 2017/8-2020/1. Higher rates of closure make scarcity much more likely in GB and this impact the effectiveness of the interconnectors as a source of capacity to the I-SEM. Sensitivities were carried out to gauge the impact of more rapid or slower tightening of reserve margins as coal capacity closes before replacement capacity enters the market.

## 6.3 Available I-SEM Capacity

6.3.1 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.

6.3.2 Ideally, the available I-SEM capacity would be based on the Capacity Requirement determined for the relevant forecast year. However, the effective interconnector capacity is an input to this calculation. Instead, a proxy value was used in the analysis.

6.3.3 The modelling work carried out by the TSOs for the wider de-rating methodology has indicated that the sum of the TER peak demand and the operational reserve requirement is a good basis for determination of the out-turn Capacity Requirement. Clearly, the continuation of this relationship will need to be monitored and the methodology adjusted, if required.

6.3.4 To convert the Capacity Requirement (and the proxy used by this methodology) to the available I-SEM capacity, it needs to be uprated to account for the average de-rating factor applied. Again, the nature of the de-rating process means this has had to be estimated for this analysis. For this paper, a value of 7% was used.

6.3.5 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.

6.3.6 Given that both the Capacity Requirement and the average de-rating factor have had to be estimated, sensitivities were performed against both of these values to see how they impact the effective interconnector capacity. In both cases, the impact is very modest and the sensitivities are discussed further in section 9 below.

# 7. Determining Effective Capacity

## 7.1 Overview

7.1.1 For each of the I-SEM and GB, the net available capacity is determined as set out in section 6, i.e. how much conventional capacity exists to meet the demand and reserve requirement in a given simulated half-hour.

7.1.2 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.

7.1.3 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.

7.1.4 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.

7.1.5 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, $\mathbf{p(G)}$.

7.1.6 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[3] 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: $\mathbf{p(S_{end}|G)}$.

7.1.7 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.

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

7.1.8 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:

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

7.1.9 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 scarcity will occur in both the I-SEM and GB, $p(S_{end} \cap G)$. The ratio of these two quantities gives the expected

[3] 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.

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)**.

7.1.10 The Effective Interconnector Capacity can then be determined as **1- p(interconnector capacity ineffective).**

7.1.11 Given the number of scenario days run (500,000) and the typical number of winter working days in a year (~125) it is possible to determine the average number of hours of scarcity being simulated in each year for both the I-SEM and GB. Whilst the exact value varies according to the sensitivity run (of which more details are given in section 9), for a "base" run, the values produced are consistent with the security standards in both the I-SEM and GB (i.e. 8 hours and 3 hours respectively). This gives improved confidence, that despite the assumptions and simplifications taken to perform the analysis, the results are meaningful and bear the expected relation to reality.

## 7.2 Coincident Outage Probability Distribution

7.2.1 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.

7.2.2 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 try and 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.

7.2.3 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".

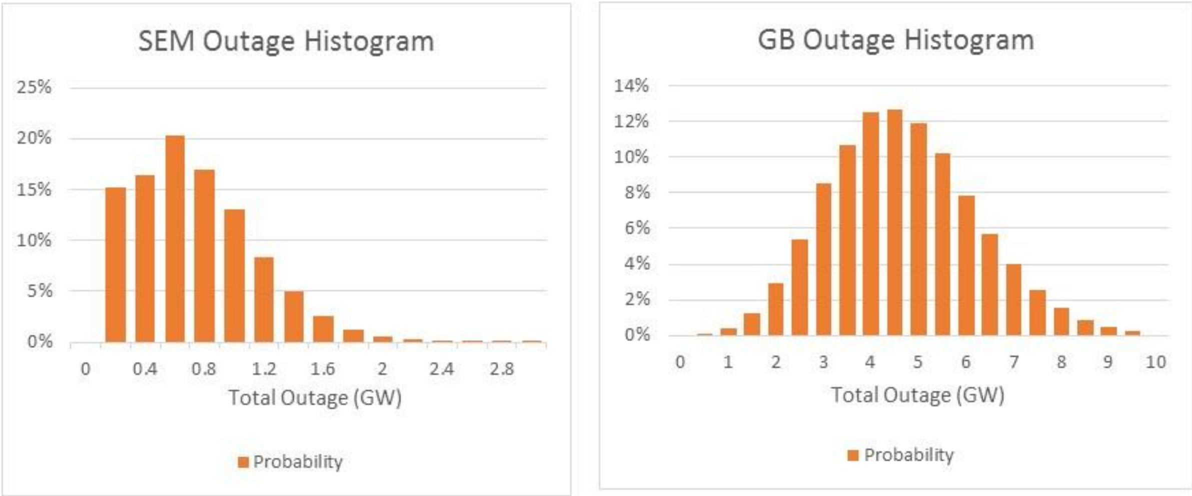


**Figure 4: Outage Histograms for the SEM and GB**

# 8. Interconnector Technical Availability

8.1.1 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.

8.1.2 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.

8.1.3 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.

8.1.4 Outage data for Moyle and EWIC was obtained from two sources:

- Reporting by the interconnectors themselves covering the period from 1/4/2004 for Moyle and 1/5/2013 for EWIC, and
- Reporting of the Eirgrid/SONI Operation outage data produced by the TSOs. This covers the years 2011 to 2015 (inclusive).

8.1.5 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. This is likely to distort the value of Forced Outage Rate (FOR) derived.
- EWIC has only been commissioned since May 2013. This means it has no overlap with “normal” outage conditions on Moyle.

8.1.6 In the long-term, these impacts should be ameliorated and an approach more fully consistent with that used for other Technology Classes can be used.

8.1.7 The length of the recent Moyle outage, in a Technology Class with only two members, means that it significantly distorts the value of FOR. SOR is also likely to be affected as there will have been no scheduled outages on the affected pole for the length of its forced outage. It is proposed that the FOR and SOR contribution from Moyle exclude the period of the extended outage. As a result, the running-hour weighting will be applied at the interconnector level to the data from the interconnectors, though due to the short data series this approach cannot be applied to the TSO data.

8.1.8 The use of running-hours weighting on a year-by-year basis to form the average outage rates is then impractical given the minimal overlap of the two interconnectors.

8.1.9 The TSO data was considered the more appropriate data source and this analysis yields the following outage rates for the Interconnector Technology Class:

| *Data Source* | *Moyle* | | *EWIC* | | *Interconnectors* | |
|---|---|---|---|---|---|---|
| | ***FOR*** | ***SOR*** | ***FOR*** | ***SOR*** | ***FOR*** | ***SOR*** |
| **TSO Operations data** | 9.8% | 1.3% | 1.2% | 3.3% | 5.6% | 2.3% |

8.1.10 These rates for the Interconnector Technology Class will be used in the TSO De-Rating Methodology along with the Effective Interconnector Capacity for each of the interconnectors.

# 9. Results and Conclusion

## 9.1 Results

9.1.1 This paper was developed in parallel with the TSO paper setting out the broader methodology for determining the Capacity Requirement and De-Rating Factors. As explained in the description of the methodology, a number of the inputs to this methodology are estimates of the results from the TSO Methodology and the results from this methodology act as inputs to the TSO Methodology. Given the timing of the two papers, the inputs to the modelling implementing this methodology could not be taken from the current results of the TSO methodology and were taken from an earlier iteration.

9.1.2 The results given in this section should be considered *Indicative* only. This consultation is on the methodology, including its inputs, and the results are provided for illustrative purposes only.

9.1.3 A "base" case was created as described in the previous sections which offers a reasonably balanced approach to the assumptions made. This base case just captures those periods in the I-SEM for which true scarcity occurs, i.e. it approximates to an average of 8 hours of scarcity per year.

9.1.4 This basic case was run for each of the years 2017/8, 2018/9, 2019/20 and 2020/1. Over this period, the changes in effective interconnector capacity track broadly with the changes to the GB generation portfolio.

| ***Year*** | ***2017/8*** | ***2018/9*** | ***2019/20*** | ***2020/21*** |
|---|---|---|---|---|
| ***Effective Interconnector Capacity*** | 89% | 95% | 88% | 86% |

9.1.5 The same Forced and Scheduled Outage Rates would be applied to all four Capacity Years, these values are:

| ***Data Source*** | ***Interconnectors*** | |
|---|---|---|
| | ***FOR*** | ***SOR*** |
| **TSO Operations data** | 5.6% | 2.3% |

9.1.6 Given the indicative de-rating factors produced by the TSO de-rating methodology, the overall de-ratings for the interconnectors would be:

| ***Year*** | ***2017/8*** | ***2018/9*** | ***2019/20*** | ***2020/21*** |
|---|---|---|---|---|
| ***Overall EWIC De-Rating*** | 76% | 81% | 75% | 74% |
| ***Overall Moyle De-Rating*** | 78% | 84% | 77% | 76% |

The higher de-ratings for EWIC are a result of its larger size and the 100MW bins used for determining marginal de-ratings in the TSO paper.

9.1.7 Given the range of assumptions being made, it was important to look at a range of sensitivities around the base case.

9.1.8 A series of changes to the underlying assumptions act to increase the number of hours for which the I-SEM is considered to have scarcity, e.g. changes to the assumptions underlying the available I-SEM capacity or the operational reserve requirement. Such a sensitivity also seems sensible given that there will be a desire to utilise the interconnectors for import before the I-SEM is actually in shortfall. These have been considered together, rather than as separate sensitivities relating to each variable.

9.1.9 In a similar manner, a series of changes to the underlying assumptions will increase the number of hours for which GB is considered to have scarcity, e.g. changes to the assumptions underlying the available GB capacity or changes to the operational reserve requirement. Such a sensitivity also seems sensible given that it may be problematic to import from GB before the market is actually in shortfall.

9.1.10 Other sensitivities, where changes to different inputs do not have a common effect are considered separately, e.g. changing the simplifying assumptions for outages, modifying the correlations between SEM and GB demand.

9.1.11 The largest impact came from changes to the GB generation portfolio and, in particular, the rate at which closure of conventional capacity out-paces its replacement. The Capacity Year 2020/1 was modelled with changes to the assumed generation capacity in GB, relative to the base case, as follows:

- an additional 1GW of capacity, similar to the No Progression scenario in the FES, and
- 1GW less capacity, similar to the Gone Green scenario in the FES.

9.1.12 The Year 2020/1 was also modelled with a 250MW reduction in available capacity in the I-SEM relative to the base case.

9.1.13 To test the impact of the highest demand days tending to have lower wind production, a sensitivity was produced with the I-SEM wind production was scaled down when the peak demand for a scenario day was forecast to be above 90% of the annual peak demand. The assumed wind production was scaled down linearly as demand rose above the 90% level so that it was at only half of it base case value at 100% of annual peak demand.

9.1.14 To test the sensitivity to the outage assumptions, the Capacity Year 2020/1 was modelled as follows with a higher assumed outage rate of 9%.

9.1.15 To test the sensitivity to the correlation between demand in the I-SEM and GB, the Capacity Year was modelled with a correlation set 10% higher than in the base case, i.e. a correlation of 0.85. This will capture the impact of demand peaks having greater coincidence in the two markets.

9.1.16 The sensitivity results are summarised in the table below:

| ***Description of Case for 2020/1*** | ***Effective Capacity*** |
|---|---|
| Base Case | 86.3% |
| +1GW GB available capacity | 91.9% |

| | |
|---|---|
| -1GW GB available capacity | 78.6% |
| -250MW I-SEM available capacity | 85.6% |
| Increased assumed outage rate | 78.8% |
| Reduced wind at highest demand | 85.7% |
| Increased demand correlation | 85.1% |

9.1.17 Most of the sensitivities only move the effective interconnector capacity by a couple of percentage point, but changing the GB generation portfolio within the range of outcomes covered by the National Grid FES has a more dramatic effect.

## 9.2 Consultation Questions

9.2.1 The SEM Committee welcomes views on all aspects of the methodology proposed and the historic and forecasts inputs used including:

A. The determination of Effective Interconnector Capacity; and

B. The use of the TSO De-Rating Model to use the RA-determined values of Effective Interconnector Capacity and the outage rates for the interconnector Technology Class to determine the marginal de-rating factors to be applied to the interconnectors.

9.2.2 The SEM Committee would particularly want to receive evidence supporting any alternative to the methodology proposed in this paper, where possible supported by quantitative analysis.

# 10. Annex: Inputs to the Methodology

This annex summarised the primary inputs used in the methodology to obtain the indicative results:

**Demand Forecasts**

The I-SEM demand forecast was taken from TER peak demand for the SEM included in the 2016 GCS produced by the Eirgrid and SONI. The median scenario was used.

The GB demand forecast was taken from the "peak Active ACS unrestricted National Demand" included in the 2015 ETYS produced by National Grid. The Slow Progression scenario was used[4].

| | ***2017*** | ***2018*** | ***2019*** | ***2020*** |
|---|---|---|---|---|
| I-SEM | 6888 | 6938 | 6980 | 7038 |
| | ***2016/7*** | ***2017/8*** | ***2018/9*** | ***2019/20*** |
| GB | 53760 | 53320 | 52880 | 52440 |

Table 1: I-SEM and GB Demand Forecasts (MW)

**Historic Demand data**

Half-hourly demand data for the Northern Ireland was obtained from the SONI website (System Output) covering the years 2010 to 2015 (inclusive).

Half-hourly demand data for the Republic of Ireland was obtained from the SEM-O website covering the years 2010 to 2015 (inclusive).

Half-hourly demand data for GB was obtained from the National Grid website (Operational Data) covering the years 2010 to 2015 (inclusive).

**Wind Forecasts**

The forecast wind capacity for the I-SEM was taken from Appendix 2 of the 2016 GCS.

The forecast wind capacity for GB was taken from the 2015 FES, for the Slow Progression scenario covering transmission connected capacity only.

| | ***2017*** | ***2018*** | ***2019*** | ***2020*** |
|---|---|---|---|---|
| I-SEM | 4033 | 4489 | 5011 | 5352 |
| | ***2016/7*** | ***2017/8*** | ***2018/9*** | ***2019/20*** |
| GB | 9129 | 10373 | 12625 | 13762 |

Table 2: I-SEM and GB Wind Forecasts (MW)

[4] The values were estimated from the graph given as figure 2.2.

### Historic Wind data

Half-hourly wind data for the Northern Ireland was obtained from the SONI website (System Output) covering the years 2010 to 2015 (inclusive).

Half-hourly wind data for the Republic of Ireland was obtained from the SEM-O website covering the years 2010 to 2015 (inclusive).

Half-hourly demand data for GB was obtained from the National Grid website (Operational Data) covering the years 2010 to 2015 (inclusive).

### Available GB Capacity

The GB generation portfolio, split by fuel type, was taken from the 2015 FES produced by National Grid. Only transmission connected capacity was used.

| | *2016/7* | *2017/8* | *2018/9* | *2019/20* |
|---|---|---|---|---|
| GB Capacity (less wind and interconnectors) | 59,199 | 60,132 | 57,870 | 55,519 |

Table 3: Forecast GB Capacity (MW)

Interconnector capacity was estimated using the 2015 FES portfolio for capacity and the sequence of new interconnector installation given in the 2015 ETYS. De-rating factors were taken from the DECC letter to National Grid dated 8 July 2016 setting out the factors to be used in the GB capacity market.

| *Interconnector* | *2016/7* | *2017/8* | *2018/9* | *2019/20* | *DRF* |
|---|---|---|---|---|---|
| IFA | 2000 | 2000 | 2000 | 2000 | 60% |
| BritNed | 1000 | 1000 | 1000 | 1000 | 74% |
| NEMO | | | | 1000 | 77% |
| ElecLink | | | | 1000 | 65% |

Table 4: GB Interconnector contribution to GB portfolio

### Generation Stacks used for outage analysis

For the I-SEM, the generation stacks for dispatchable plant given in Appendix 2 of the 2016 GCS were used.

For GB, the generation stack given as part of the FES (Appendix F) is not consistent with any of the four scenarios. A stack was created using BM Unit data provided from the Elexon Portal, corrected for units which have already closed.

### Interconnector outage data

Outage data for Moyle and EWIC was obtained from two sources being the interconnectors directly and the TSOs operational data. These data sets showed some correlation. For this modelling purpose the TSO operational data has been applied.