I-SEM
Capacity Remuneration Mechanism:
Proposed Methodology for the Calculation of the Capacity Requirement and De-rating Factors

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EIRGRID semo Single Electricity Market Operator SONI

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Executive Summary

On the 1st of July 2016, NIAUR and CER issued decisions on proposed modifications to licences held by SONI ltd. and EirGrid Plc. These modifications add responsibility for the Capacity Market Code (CMC) to the suite of obligations that are already placed on us under our TSO licences. The proposed modifications to the TSO licences suggest that the Capacity Remuneration Mechanism (CRM) auction process and parameters will be defined in the CMC. The CMC will be designated by the Regulatory Authorities (RAs). Based on SEM Committee decisions to date, our understanding is that the TSOs will be required under the designated CMC to calculate the capacity requirement for the I-SEM CRM and also to assess the de-rating factors that will be applied to capacity participating in the auction and secondary trading.

As outlined in SEM-016-041, we expect the designated CMC to include a requirement for the interconnector de-rating methodology to be developed by the RAs and for the capacity requirement and other de-rating factors to be approved by the RAs.

The methodology presented in this document builds on the existing generation adequacy methodology that is employed by the TSOs to produce the annual Generation Capacity Statements. It has been adapted to use multiple demand scenarios and to enable the determination of marginal de-rating factors.

In accordance with SEM Committee decisions, units are divided into a number of technology categories. Outage statistics are calculated for each of these categories using historical SEM outage data. The proposed de-rating methodology calculates the marginal benefit of each unit type and size to the system. A number of portfolios that meet the adequacy standard are constructed. The unit's marginal de-rating factor is calculated as the MW change in surplus (above the adequacy standard) due to the addition of the unit divided by the MW capacity of the unit. This is done for the range of unit types and size categories and demand scenarios. The de-rated capacity requirement is then the sum of the de-rated capacity in the portfolios.

A Least-Worst Regrets analysis is performed to select the demand scenario and associated capacity requirement. For the values presented in this document (set out in section 9), the de-rating factors are those that are used to derive the capacity requirement selected by the Least-Worst Regrets analysis. Note that these values are indicative for the purpose of the consultation and should not be considered as final.

This paper is premised on the assumption that the allocation of responsibilities under the designated CMC will be those set out above. Consequently, the paper outlines SONI and EirGrid's proposed methodologies for calculating these parameters, and we welcome feedback on them.

Part A – Introduction and Overview

1 Introduction

1.1 Background

On the 1st of July 2016, NIAUR and CER issued decisions on proposed modifications to licences held by SONI ltd. and EirGrid Plc. These modifications add responsibility for the Capacity Market Code (CMC) to the suite of obligations that are already placed on us under our TSO licences.

The SEM Committee has decided that the Capacity Remuneration Mechanism (CRM) is to be based on reliability options, which will be auctioned to potential capacity providers. The proposed modifications to the TSO licences indicate that the auction process and parameters will be defined in the CMC, and that the CMC will be designated by the Regulatory Authorities (RAs).

Based on SEM Committee decisions to date, our understanding is that the TSOs will be required under the designated CMC to calculate the capacity requirement for the I-SEM CRM and also to assess the de rating factors that will be applied to capacity participating in the auction and secondary trading. As outlined in SEM-016-041, we expect the designated CMC to include a requirement for the interconnector de rating methodology to be developed directly by the RAs and for capacity requirement and other de rating factors to be approved by the RAs.

This paper is premised on the assumption that the allocation of responsibilities under the designated CMC will be those set out above. Consequently, the paper outlines SONI and EirGrid's proposed methodologies for calculating these parameters, and we welcome feedback on them.

This document proposes a methodology for setting the de-rated capacity requirement and for the de-rating of generating units and demand side units as part of qualification for the I-SEM Capacity Remuneration Mechanism (CRM). Indicative results are presented demonstrating the application of this methodology.

The de-rated capacity requirement reflects the aggregate de-rated capacity required to satisfy the unconstrained All-Island adequacy standard. The RA's may choose to adjust the auction capacity requirement from this de-rated capacity requirement for a number of reasons, including (but not limited to) non-bidding capacity, de-rating factor tolerance bands and expected failure to deliver capacity.

1.2 Relevant SEM Committee Decisions

The methodology described in this document has been prepared on the understanding that the designated CMC and the agreed procedures that will sit under it will align with published decisions of the SEM Committee. The key SEM Committee decisions that have shaped the methodology proposed are that:

- "the procurement of Reliability Options under the I-SEM should be based on a de-rated requirement." [*CRM Consultation 1, section 2.3.8*].
- "the development of de-rating factors should proceed on the basis that:
    - Central de-rating factors will be technology specific, but make allowance for the impact of plant size. At minimum, plant of the same technology but of significantly different

    unit sizes should have different de-rating factors, and may reflect plant specific history or known future events - such as extraordinary planned outages.
  - Be based on marginal contribution to meeting the capacity requirement;
  - Be centrally determined by the TSOs, with the TSOs determining de-rating factors for groups of technologies.
  - Be based on TSO analysis of the marginal contribution of the relevant technology to the capacity requirement. That is the extent to which a marginal increment or decrement of nameplate capacity from that technology type impacts the overall requirement for nameplate capacity
  - Vary for characteristics of a technology (e.g. size) that can be parameterised, and which legitimately impacts its marginal impact on the capacity requirement." [*CRM Consultation 1, section 4.7.30*].
- "the I-SEM capacity requirement should be determined for the I-SEM as a whole, rather than for separate zones within the I-SEM" [*CRM Consultation 1, section 2.5.9*].
- "… the I-SEM capacity requirement should be determined based on the analysis of a number of scenarios for demand. These scenarios should provide reasonable coverage of the potential future requirement for capacity. The capacity requirement should be determined for each scenario, and the optimal scenario selected based on the least regret cost approach…." [*CRM Consultation 1, section 2.4.13*].
- "non-firm transmission access generators be:
  - Eligible to bid, subject to the same de-rating factors as firm generators of the same technology;
- It has been decided to "retain the existing (8 hour LOLE) security standard" [*CRM Consultation 1, section 2.2.16*].

1.3 Scope

The TSOs have been tasked by the RAs to lead the development of analytical methods that will determine the marginal de-rating factors and the total de-rated capacity requirement. The RAs will separately consult on the methodologies, based on this TSO report. The analysis conducted focuses on the four 12-month capacity years commencing from October 2017.

The methodology for determining Interconnector de-rating factors is being developed by the RAs and this will be consulted upon in their associated document. The TSOs will determine the marginal de-rating factor applicable to interconnectors based on the values supplied by the RAs using the same process that applies to other units.

The results presented are provided to inform responses and are indicative only. The actual assessment will be undertaken in line with this consultation's decision paper and will reflect feedback received through the RAs consultation process. Any approval of these parameters will also be obtained under the processes outlined in the decision paper.

The focus of this paper is to present and seek feedback on the proposed methodology for determining those de-ratings factors and the associated Capacity Requirements.

1.4 Outline

This document is structured as follows:

- Section 2 provides a high level overview of the methodology adopted. This section will be useful to readers who only require a general understanding of the process.
- Section 3 describes the demand scenarios used and how they were formed.
- Section 4 describes how data on generators and demand side units was sourced. Treatment of other technology's not currently operating in the SEM is also discussed.
- Section 5 describes the formation of technology categories and presents results for their statistics.
- Section 6 describes how the marginal de-rating process works. This section will be useful to readers who are interested in understanding the detail of the process.
- Section 7 describes the least-worst regrets analysis.
- Section 8 discusses the enduring process.
- Section 9 presents the indicative results.
- Section 10 presents some operational considerations of the implication of an unconstrained All-Island capacity requirement
- Section 11 provides a glossary of terminology.

2 Overview of Methodology

This section presents a brief overview of the methodology for determining the de-rated capacity requirement and the de-rating factors for capacity market units. It is provided to help the reader understand each section of the document in the context of the overall method. The method involves the general steps outlined in Figure 1.

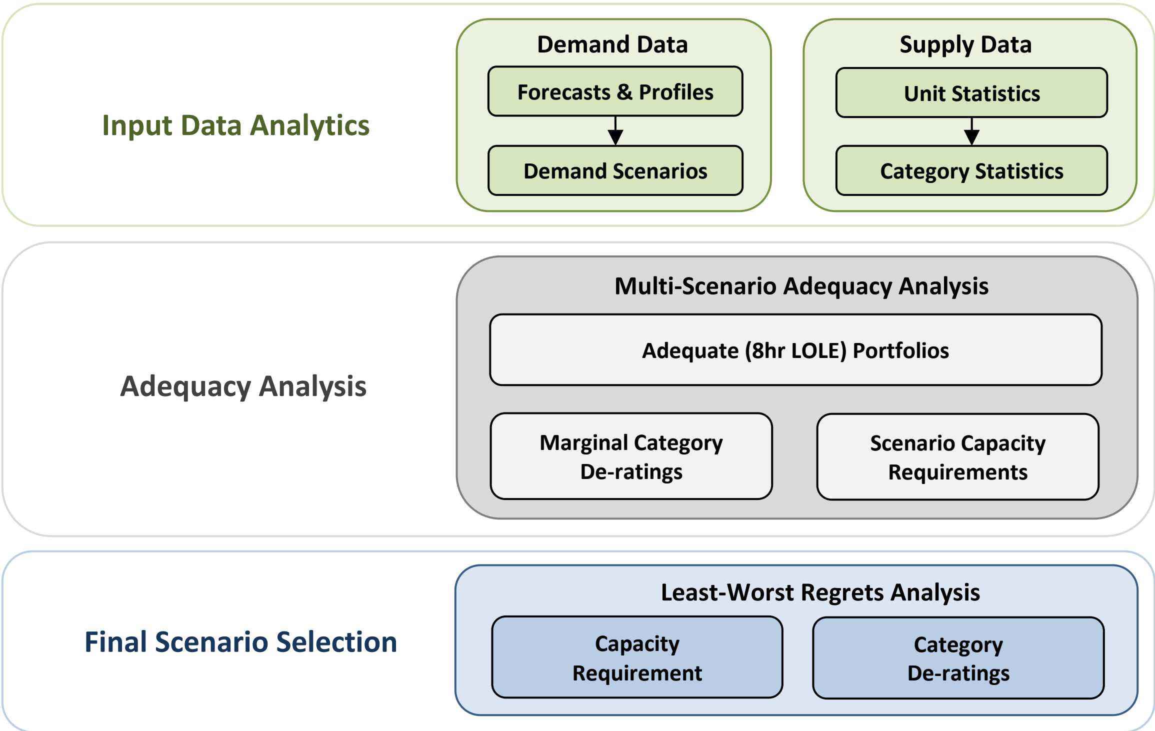

Figure 1: Conceptual Overview of the Methodology

The Input Data Analytics phase involves sourcing and processing demand data and power supply data to be used in the analysis.

Forecasts of future demand are needed to determine the capacity required to serve that demand. The methodology uses a range of demand scenarios for each capacity market year analysed. The demand scenarios differ based on annual demand growth and how that demand is distributed - or profiled – across the year. The information to form these demand scenarios is sourced from EirGrid and SONI's current Generation Capacity Statement (GCS).

The methodology uses the historical outage data of capacity market units, such as generators and demand side units. This outage data includes the level of forced and scheduled outages and ambient (e.g. temperature dependent) outages. A separate process is proposed (see section 4) for determining availability data for technologies that do not currently exist within the SEM.

The methodology does not determine de-ratings for individual capacity market units based just on that unit's data alone. Instead, each capacity market unit is associated with a "technology category", e.g. "steam turbines" and "hydro". Average outage statistics for each technology category are formed from the historical outage data for the individual capacity market units within that technology category. The averaging serves to make the data more consistent, smoothing out random variability within a technology category, and making the data more stable between auctions.

The Multi-Scenario Adequacy Analysis seeks to derive de-rating factor curves as a function of the size of a unit. These curves can be applied to the MW capacity of the capacity market units belonging to that technology category to give a de-rated capacity. The starting point for analysing marginal de-rating is the production of one or more capacity adequate portfolios. A capacity adequate portfolio comprises of a set of capacity market units that together satisfy the 8 hour LOLE standard for a demand scenario. A capacity adequate portfolio is formed from the set of existing capacity market units expected to be in the auction and new capacity market units. These portfolios provide a reference or base set of data relative to which the marginal de-rating analysis can be performed. In the current analysis, five different capacity adequate portfolios were produced for each demand scenario in order to simulate a range of possible auction outcomes.

A marginal category de-rating factor is determined by looking at the impact on the simulated LOLE outcomes of adding a single notional unit of a specific technology category and size to each capacity adequate portfolio for a demand scenario. By varying the size of this notional unit and by moving it between technology categories it is possible to form a curve of the de-rating factors associated with a unit of any size for any technology category. Adding a notional unit of a given size to a capacity adequate portfolio increases the capacity of that portfolio. This will reduce the LOLE for that demand scenario and portfolio combination to a level below 8 hours. This new portfolio is then simulated repeatedly, but with the demand in all hours increased gradually until that portfolio again just satisfies the LOLE standard of 8 hours. The ratio of the final increase in demand to the capacity of the notional unit gives the marginal de-rating of the notional unit. Thus if the notional unit has a capacity of 20 MW, this might reduce the levels of unserved load in a few hours of the year, lowering the LOLE. If adding 18 MW of demand in every hour raises the LOLE back to 8 hours then the de-rating factor of this unit is 18/20 = 0.9. The implied de-rated capacity of the unit is then 0.9 × 20 = 18 MW.

The de-rating factor curves for each technology category are averaged across the capacity adequate portfolios associated with a demand scenario. This gives a single de-rating factor curve for each technology category for that demand scenario. Applying these de-ratings to the units within each capacity adequate portfolio also gives the de-rated capacity requirement. The largest of these de-rated capacity requirements is the value associated with that demand scenario.

The final scenario selection serves to identify which demand scenario will be chosen as the basis for de-rating factors and the de-rated capacity requirement for that Capacity Year. A “least-worst regrets” analysis is performed. The least-worst regrets analysis simulates the performance of the capacity adequate portfolios for each “base” demand scenario across all potential “other” demand scenarios:

- If the other demand scenarios have greater demand than the base demand scenario then the levels of unserved energy would rise, at a cost equal to the Value of Lost Load (VOLL), which is measured on a €/MWh basis.

- If the other demand scenarios have lower demand than the base demand scenario has more capacity than is required to satisfy the 8 hour LOLE standard. The difference between the capacity requirements of the two scenarios reflects the cost of surplus capacity, which is priced at the value of the Best New Entrant capacity on a €/MW basis.

The base demand scenario selected is that with the least combined regret cost due to both shortages of energy and over-supply of capacity. The de-rated capacity requirement for this demand scenario is selected as the result of this analysis. The de-rating factor curves for each technology category associated with this base demand scenario are applied to the registered capacity of the capacity market units when determining their de-rated capacity.

The RA's may choose to adjust the auction capacity requirement from this de-rated capacity requirement for a number of reasons, including (but not limited to) non-bidding capacity, de-rating factor tolerance bands and expected failure to deliver capacity. Such adjustments are beyond the scope of the methodology presented in this document.

Part B - Input Data Analytics

3 Demand Scenarios

3.1 Introduction

This section describes the approach for forming demand scenarios, where a demand scenario is a combination of an annual demand forecast (both peak MW and total MWh) and a demand profile which describes how to allocate that demand across all the hours in a year.

3.2 Source of Demand Forecasts

The demand forecast data used in setting the I-SEM capacity requirement and in determining de-rating factors is sourced from EirGrid and SONI's current Generation Capacity Statement (GCS)[1]. Using GCS data ensures consistency and continuity with current adequacy assessments. The GCS provides detail of the development of both the source and development of demand forecast data.

The GCS low and high forecasts of MW peak demand and annual GWh total energy requirement (TER) are taken as the extreme demand forecasts. These forecasts reflect All-Island demand and include transmission and distribution losses. The forecasts reflect the total quantity of energy required to be supplied.

An additional eight demand forecasts are interpolated at equal intervals between these to provide 10 different annual demand forecasts. This increase in the range of demand forecasts provides finer resolution in the analysis. This is illustrated in Figure 2. The forecast demand profiles used in the analysis are built (using the historical base profiles discussed below) so that the energy and peak match the forecasted energy and peaks

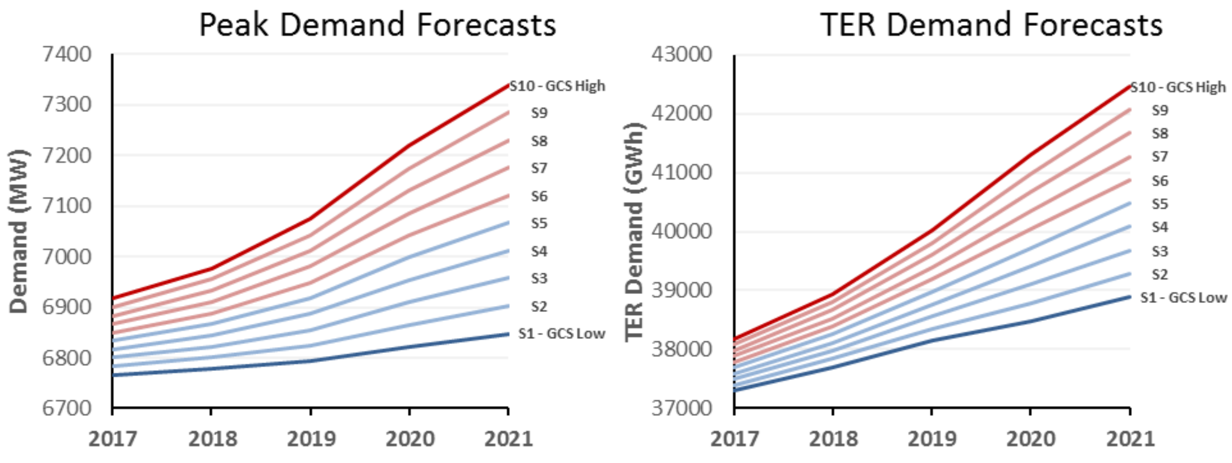

Figure 2: Formation of the Demand Forecasts

[1] "Generation Capacity Statement 2016 – 2025" was used in this indicative analysis. This was based on data available as at October 31st 2015.

3.3 Source of Demand Profiles

The de-rating analysis presented here is based on hourly demand data. Half-hourly demand data can also be used. A set of eight annual demand profiles have been used in this analysis. Figure 3 gives load duration curves for 2007 to 2014. It shows that there has been considerable variability in demand over those years. A set of hourly demand scenarios is formed by combining each demand forecast with each demand profile. Each demand scenario comprises a set of hourly demand values for a year reflecting the pattern of demand profile used, with a peak demand and total annual energy requirement from the demand forecast.

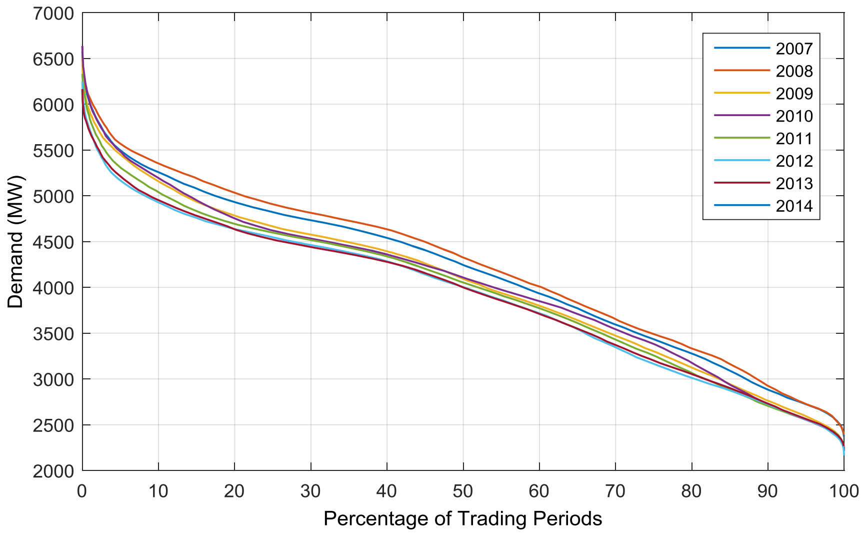

Figure 3: Historical load duration curves for 2007 to 2014.

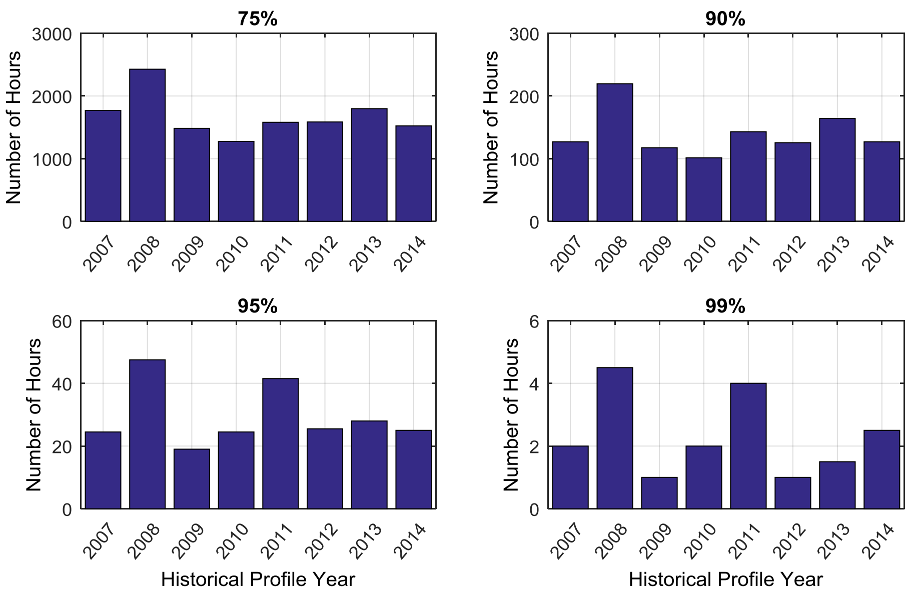

Figure 4: Variability of Peak Demand across Demand Profiles

Figure 4 indicates the differences in the historic annual demand profiles. The charts show the number of hours per year that demand exceeded a specified proportion of peak demand. It shows that the 95th percentile of demand could occur between 18 and 47 hours per year depending on the profile. These differences can have a significant impact on the LOLE for a given portfolio of capacity market units. As different demand scenarios are based on different demand profiles, the data has a diverse mix of demand over the year and variability of demand within the year.

3.4 Non-Market Demand

In GCS studies, small-scale non-market generators are modelled as part of the adequacy studies, though larger, conventional units dominate the results. In the CRM, it is proposed to net off the generation provided by the non-market sector. In 2015, the Total Electricity Requirement was 36.5 TWh while the total Market demand was 33.5 TWh, making the non-market demand approximately 3 TWh, or 8% of TER (this has grown steadily from 4% in 2008).

In order to estimate the amount of non-market generation for future years, it is necessary to forecast the installed capacity of each class of non-market generation. This exercise is carried out annually for the GCS (see Tables in Appendix 2 of the GCS). The sectors which are predicting the most growth are solar, wind and biomass CHP. It is assumed that most of the growth in Biomass CHP in Ireland will be with larger units that will participate in the market. In the wind sector, it is assumed that any wind farm less than 10 MW is not in the market. This accounts for approximately 17% of total wind capacity, and it is assumed for the purpose of these estimations that this percentage continues.

It is also important to predict the performance of these non-market units, i.e. their capacity factor, as this determines the level of annual demand from the TER that they offset. This is done by examining the current generators in this sector based on historical data. To adjust the peak for the non-market wind, it is proposed to not use the annual capacity factor, but rather the Wind Capacity Credit which is lower, but could give a more realistic view of what these units might be contributing at any time (see section 3.5(c) of the current GCS). Solar units greater than 10 MW are assumed to be in the market, while those less than 10 MW are assumed not to be in the market.

Figure 5 below gives the adjustment from forecast TER peak demand to forecasted market peak demand for the years 2017 to 2021. While it is recognised that market design changes in the I-SEM may cause some of these units to enter the market, given the uncertainty this has not been accounted for in the current analysis.

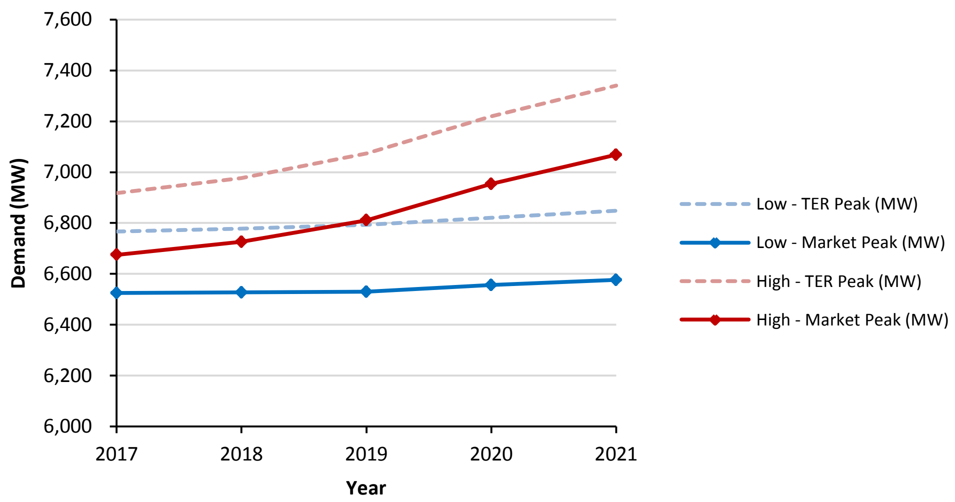

Figure 5: TER and Market peak forecasts

3.5 Reserve to Cover the Largest Single Infeed

In line with the approach being adopted by ENTSO-E for the Mid Term Adequacy Forecast[2], for the indicative results provided in this paper, we have included a provision for reserves on top of demand prior to assessing the adequacy of the portfolios. The inclusion of a provision for reserves also aligns also with the approach taken for the GB Capacity Market, where 0.9 GW is added to cover the loss of the single largest infeed, and reflects the need to have not only sufficient capacity to meet demand but also to have sufficient capacity to maintain required reserves. The largest single infeed used in this analysis was 444 MW and corresponds to the firm capacity of the largest single generator on the current system. This reserve requirement is added to the demand in all scenarios studied.

While not a feature of the current approach in the CPM, the inclusion of a provision for reserve in the new capacity requirement methodology in our view is an important consideration. In the context of the new Capacity Market, only capacity providers that clear in the auction will receive capacity payments (unlike the current mechanism where all eligible available capacity is remunerated). In tandem with the increased role of system services, setting the capacity requirement at a level that ensures a secure system is of greater importance.

	2017	2018	2019	2020
GCS Low TER Peak Demand	6,767	6,778	6,793	6,821
GCS Median TER Peak Demand	6,888	6,938	6,980	7,038
GCS High TER Peak Demand	6,917	6,977	7,074	7,219
Small-Scale Non-market Adjustment	242	251	263	265
Low Market Peak Demand	6,525	6,527	6,530	6,556
Median Market Peak Demand	6,646	6,687	6,717	6,773
High Market Peak Demand	6,675	6,726	6,811	6,954
Reserve Requirement	444	444	444	444
Low Market Demand + Reserve	6,969	6,971	6,974	7,000
Median Market Demand + Reserve	7,090	7,131	7,161	7,217
High Market Demand + Reserve	7,119	7,170	7,255	7,398

Table 1: Demand Forecast Components

4 Supply Data and Statistics

4.1 Introduction

This section presents the data sources used in this analysis for capacity market units. This data is primarily used to define average outages for different technology categories.

It is important to appreciate that while average outages for the technology categories is based on existing SEM unit data, the technology categories themselves allow the de-rating methodology to consider units which were not operating in the SEM during the period covered by the data, provided

[2] https://www.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2016_FINAL_REPORT.pdf

they are of a similar technology as that represented by an existing category. The possibility of new entrant units that are not comparable with proposed technology categories is discussed separately below.

4.2 The Set of Existing Units

The set of existing units subject to de-rating were those considered in the current GCS. These units are listed in Appendix 2 of the Generation Capacity Statement.

4.3 Sources of Data for Existing Units

4.3.1 Availability Statistics

Availability statistics were sourced for different unit types as follows:

- Distillate, Coal, Hydro, Demand Side, Peat, Oil, Pumped Storage, CCGT, Gas OCGT, CHP units
    - EDIL (Electronic Dispatch Instruction Logger)[3] records from Jan 2011 – Dec 2015 (and as at 31 January 2016) provided participant submitted:
        - Forced outage data
        - Scheduled outage data
        - Ambient outage data (applicable for CCGT, Gas OCGT, and CHP units).
- Wind units
    - Meter data from January 2007 to December 2014 was used to derive an aggregate All Island rating factor for each hour based on all wind units in the EDIL system.

A period of five years of EDIL data is used as this provides a consistent set of availability data. It might be thought that the data set could be improved by taking data from a longer time period. However, there are some practical downsides in such approach. In particular:

- The data used covers a period since the commencement of the SEM. The SEM includes a capacity payment mechanism which provides incentives to maintain availability that may not have existed prior to the SEM. Hence it seems reasonable to expect that the average availability of units post SEM go-live in 2007 should differ from their availability prior to SEM go-live.
- The primary data being used for this analysis has only been recorded in its current form since 2011. Prior to 2011 multiple data sources were used. Older availability data is not directly compatible with current availability data in terms of format or meaning, and the drivers for recording that data will be different.

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[3] EDIL is the best data source as data has been submitted by participants in the SEM to the TSO. It provides a consistent and complete data source.

- The operation of generators and maintenance patterns may have evolved with the growth of renewable generation, limiting the applicability of old data to the current environment.

The use of older data as a means of increasing sample size is not proposed as differences in its nature and the prevailing incentives may actually distort availability data.

The EDIL data was extracted via the EirGrid and SONI Monthly Availability Reports to give average monthly MW capacity reductions for each of forced outage, scheduled outage, ambient outage, and the total of these outages. These monthly averages are converted to a percentage capacity reduction and are averaged over 12 calendar months to give an average annual percentage capacity reduction due to each of forced outage, scheduled outage and ambient outage for each unit and for each of the five years of historic data.

4.3.2 Generation Data

Interval MWh generation data is required to determine the run hours for each unit. Total annual run hours are used below in determining average technology category outage statistics. The generation data used was half-hour Metered Generation data (used in market settlement) extracted from the SEM settlement database for the period January 2011 to December 2015. The data was extracted during the first week of March 2016.

4.3.3 Retirement Data

The GCS provides information on planned retirements of units. These are used to exclude such units from portfolios employed in the marginal de-rating process for post-retirement capacity years.

Retiring units are not excluded in defining average availabilities for technology categories. Retaining these units in the sample set allows the statistics to reflect a diverse array of ages of capacity market units. Excluding these units, and using current data for relatively newer units, would fail to account for unit performance changing with age.

4.4 Sources of Data for New Units

4.4.1 New Unit, Existing Category

It is proposed that new capacity that conforms to one of the existing technology categories set out in this methodology would take on the values associated with that technology category. The approach for determining marginal de-rating can determine de-ratings for a unit of any size for a given technology category. This can provide a default de-rating for any new unit that falls in the same technology category, and no data is required for such a unit. While it could be argued by the provider of such new capacity that it will perform differently from the current units, if the technology is broadly the same then assessing such variations would be very subjective and such an approach is not favoured.

4.4.2 New Unit, New Category

New capacity that does not conform to the existing categories will be given values associated with the system average. This would contribute to defining its initial de-rating factor. If the new unit accepts a multiple year reliability option contract the de-rating factor could be increased over time as actual performance data becomes available, but it cannot be decreased. For the avoidance of doubt, their reliability option quantity would only increase if they traded further in the primary or secondary auctions. Therefore, it is important to have a degree of conservatism in setting the initial de-rating factors.

While not considered currently, the treatment of other variable resources (e.g. solar, tidal, wave) would be based on an hourly variable generation profile using the relevant annual 1 MW normalized resource profile (i.e. an annual profile of values between 0 and 1 is applied to the installed capacity of that variable resource). These profiles would be incorporated into the analysis using the same methodology as is used for wind capacity.

4.5 Treatment of Capacity Aggregated Units

A capacity aggregation unit will comprise a number of individual generator units (including DSUs).

For the purpose of de-rating it is proposed to de-rate the individual generator units, and then to aggregate the de-rated results to become the de-rated capacity of the capacity aggregation unit.

This approach has a number of advantages

- It is consistent with the methodology for de-rating other generator units and requires no material change in the methodology
- It recognises that an outage of an individual generator unit in the capacity aggregation unit will not remove the full capacity of the capacity aggregation unit.
- The de-rated capacity will be greater by this method as larger individual units will be de-rated more than smaller otherwise identical units.
- It recognises that the individual generator units may be of differing technologies and should therefore be de-rated based solely on their technology category.

What this means in practice is that a capacity aggregator will seek qualification for a set of generator units, and will be awarded a de-rating factor for the capacity aggregator unit based on the sum of the de-rated capacities of the individual units. Participation in the auction and the settlement of the capacity aggregator unit will be unaffected.

5 Technology Categories

5.1 Introduction

This section describes the approach for defining technology categories to use in the de-rating methodology.

5.2 Approach

Each capacity market unit subject to de-rating is associated with a technology category. The aim is to have similar types of units in the same technology categories. De-rating factors will be determined by technology category, rather than by individual units. This is because the availability of the units in a technology category is a statistically more robust and reliable measure of future performance than the availability of the units in isolation. As an illustration, a rare type of outage that might be expected to occur once in twenty years would distort the results for an individual unit if that event happened within the five years of source data. However, if there are eight units in the technology category then over five years (i.e. 40 years of data) the event might be expected to occur twice within the technology category during the five years. The volatility of de-rating factors is also reduced by this approach.

A key advantage of this approach is that a unit with a long outage, if assessed on its own data could be significantly de-rated requiring the system to procure more capacity when it is not necessary.

There are limitations in using technology categories. For example, the de-rating factors of the technology category may be less favourable for the most reliable units in the technology category while over-stating the de-rated capacity for the least reliable units in the technology category.

On the other hand, a group average approach gives an incentive to keep the availability of a capacity market unit above the group average. If a unit's reliability is slipping relative to the group average, then this can expose the operator to increased costs in mitigating the risks of failing to deliver on reliability options. This encourages its operator to increase maintenance, or if this is not viable, to consider retiring the unit.

Larger groupings give more statistically robust outcomes; however, as the size of the group increases, their representativeness of individual units may decrease. As the I-SEM is a relatively small market, there may be merit in considering a system wide category that includes all conventional units. Data is presented in our results to show the implications of a system-wide category.

5.3 Selected Technology Categories

The technology categories used in this analysis are described in Table 2.

Technology Category	Unit types included
DSU AGU	Demand side units (including aggregated units)
Gas Turbine	CCGT, Gas OCGT, Large CHP
Hydro	Hydro
Steam Turbine	Oil, Distillate, Coal, Peat
Storage	Pumped Storage[4]
Wind	Wind
System Wide	All of the above.

Table 2: Types of Units in each Technical Category

In determining a proposed set of technology categories a range of alternative groupings were considered. The selected approach was adopted as it provides a reasonable trade-off between homogeneity of units and sample size. The homogeneity of units is reflected by grouping them based on their primary turbine technology (gas, steam, water, wind) or as demand response or storage units. By

[4] In the future this could include compressed air, battery and other grid powered storage technologies.

keeping the number of categories small the average number of units and hence data points in each category is increased, improving the quality of statistics. The smallest group is pumped storage but the unique nature of these units makes them difficult to meaningfully group elsewhere.

5.4 Averaged Availability Statistics for Technology Categories

The average annual values of each of forced outage, scheduled outage and ambient outage for a non-wind technology category is formed by an annual run-hour weighted averaging of the associated average annual values for each unit in that technology category.

The average run-hour weighted forced outage rate of a technology category is:

$$\{\sum_{unit}\sum_{year} \text{(Annual Run Hours)}_{unit} \times \text{(Average Forced Outage Rate)}_{unit}\} / \{\sum_{unit}\sum_{year} \text{(Annual Run Hours)}_{unit}\}$$

Where “unit” denotes the capacity market units in that technology category and “year” denotes each of the five years of data for which capacity market unit data is available. The annual run hours of a unit reflect the sum total of hours for which the unit had a non-zero level of export. The system-wide run-hour weighting is calculated using the same process as above by just using a system-wide category that includes all units.

A number of different methodologies were assessed, including a simple average, a capacity weighted average, an output weighted average and a run-hour weighted average. The run-hour weighted methodology was selected as there was considerable variation in unit average availabilities between peaking units – which declare availability for all hours but may only run for a small number – and lower merit order units that run more frequently. A capacity weighted approach could mean that units that run extremely rarely – and hence have availabilities that are less tested in practice - would have equal weight to units that run every day. An output weighted average has elements of both capacity and run time but heavily weighted the results to large base loaded units that run most of the time. A simple average approach took no account of unit capacity, run times or output and hence has limited relationship to reality. Giving greater weighting to the more frequently running units was considered to give a good trade-off between these issues and has the advantage of a reducing the contribution of units that have rare but very long outages, limiting the impact these have on the category weighting.[5]

The availability of the wind technology category is based on the actual output of all wind units relative to their installed capacity. Actual wind data defines a profile of wind generation for a year. Wind generator output is correlated to weather conditions and hence to demand. To account for this, the wind profile applied for a given demand scenario is the wind profile that corresponds to the historical demand profile applicable to that demand scenario.

It is important to be aware that there will be a correlation between forced outage rates of units and the level of capacity available. Currently there is a surplus of capacity and as a result some generators will be utilised less than they would be were there to be no surplus of capacity. This will tend to lower their

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[5] Consider the case of a peaking unit that runs for 2 hours per year. It may be 90% available in other hours, 100% available in the first hour it runs, but have a forced outage giving 0% availability in the second hour it runs. Its simple average availability over the year would be close to 90%, but its availability over the time it is actually called upon is closer to 50%. The run-time weighted approach would give its 90% average availability a weighting of only 2 hours in 8760 hours per year, limiting its ability to distort the technology category average.

forced outage rates. If the capacity situation becomes tighter, then these units will likely be required to run more and this could increase their forced outage rates. This in turn would imply a higher de-rated capacity requirement.

Figures 6 and 7 give the category forced and scheduled outage statistics for the different categories. The blue bars give the simple mean outage for each year. The green horizontal line gives the average weighted by total generation and the red horizontal line gives the average outage weighted by total run-hours. Table 3 also lists the relevant values. Ambient outages are profiled across the year for the gas turbine units. These ambient outages are mainly temperature related and are minimal during the winter peak. Currently, ambient outages have a minor impact on the analysis.

	Forced Outage (%)	Scheduled Outage (%)
Technology Category	**Mean**	**Mean**
Gas Turbine	3.6%	4.8%
Hydro	3.9%	12.4%
Steam Turbine	7.2%	6.5%
Storage	7.1%	4.9%
DSU AGU	24.7%	4.5%
System Wide	5.3%	7.3%

Table 3: Indicative Forced and Scheduled Outage Statistics by Technology Category

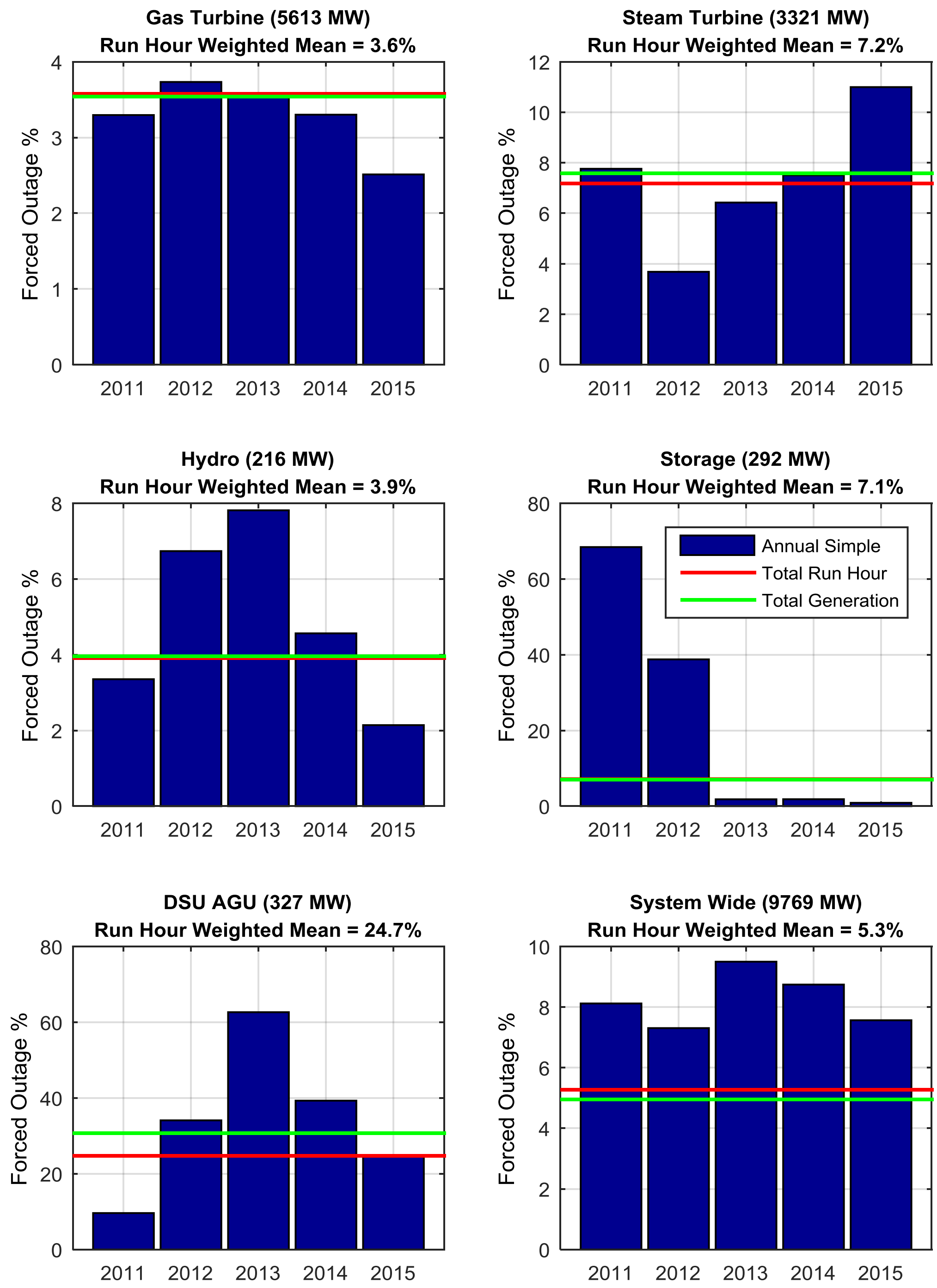

Figure 6: Category forced outage statistics. The blue bars give the annual simple average, the red line gives the run-hour weighted average and the green line gives the generation-weighted average.

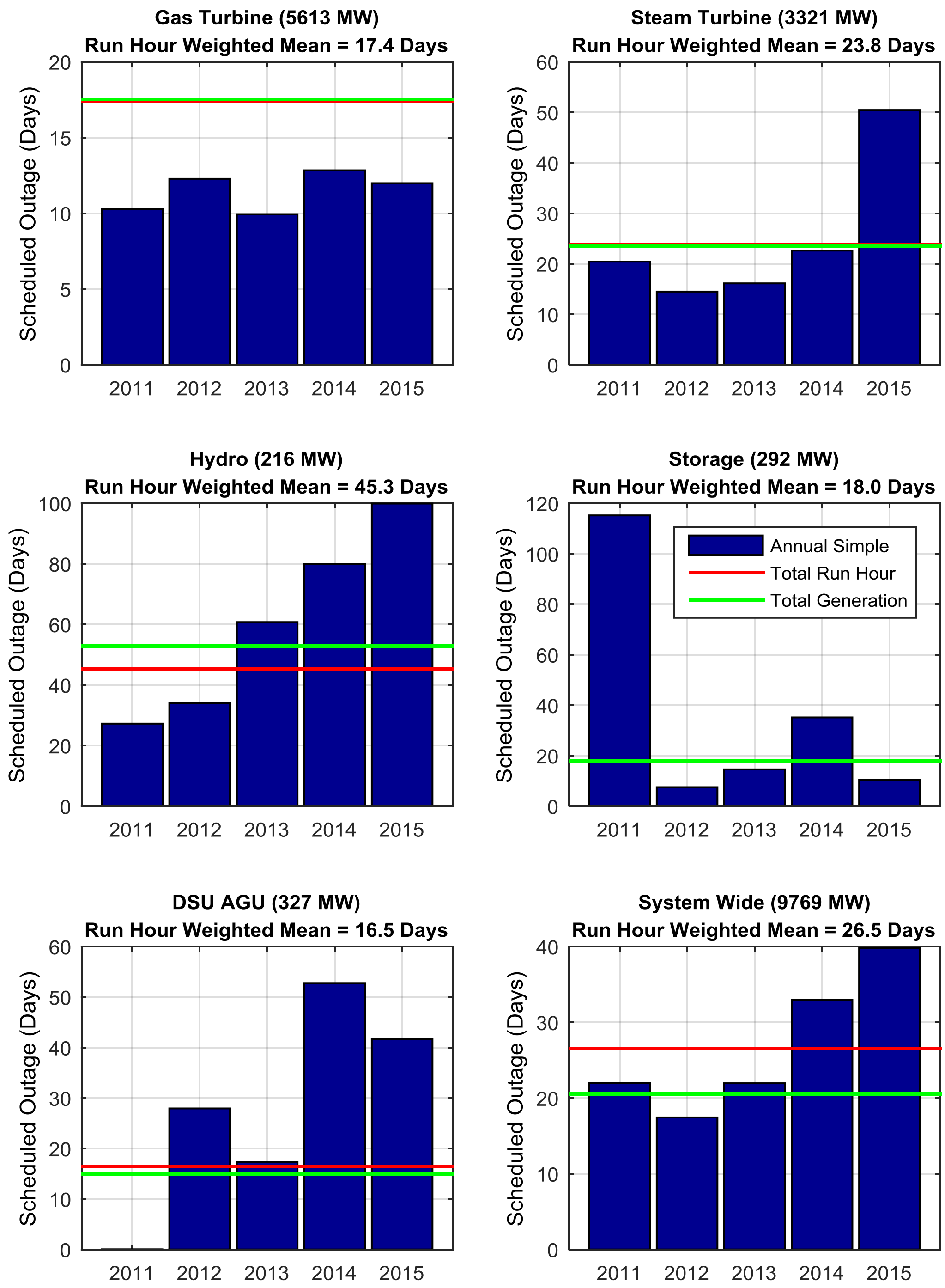

Figure 7: Category scheduled outage statistics. The blue bars give the annual simple average, the red line gives the run hour weighted average and the green line gives the generation weighted average.

Part C - Adequacy Analysis

6 Multi-Scenario Adequacy Assessment

6.1 Selection of Portfolios for Different Demand Scenarios

Section 3 described the demand forecasts and demand profiles to be applied in this analysis. A demand scenario is a combination of one of the demand forecasts and one of the demand profiles (with hourly demand increased by the largest infeed loss as described in Section 3). This produces an hourly sequence of demand for a year, with the same peak and annual demand as the demand forecast.

Figure 8 depicts how this method is used to generate the different demand scenarios for each capacity year. We use ds to denote one specific demand scenario within the set DS of demand scenarios.

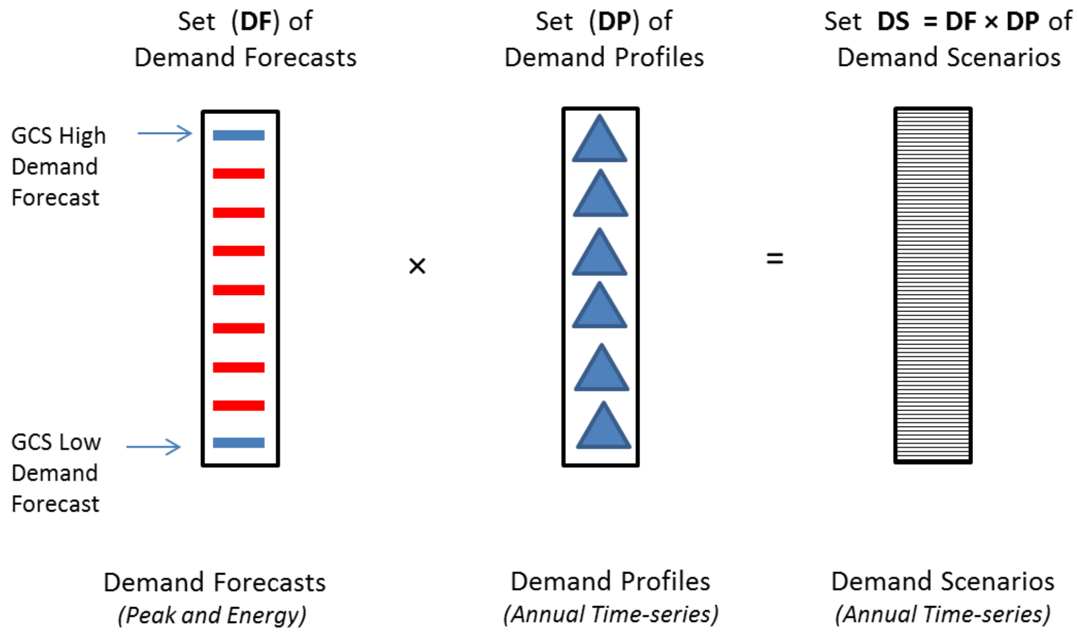

Figure 8: Formation of the Demand Scenarios

GCS data is based on a calendar year. The capacity years are based on a 12-month period beginning in October. To correct for this, the GCS data was used to generate hourly data for each calendar year to the end of 2022 with capacity year data taken from this sequence.

For each demand scenario the method determines a set of capacity adequate portfolios of generators. How this is done is illustrated in Figure 9 below. For the analysis presented in this report five different capacity adequate portfolios are simulated for each demand scenario. This is to simulate a range of possible auction outcomes.

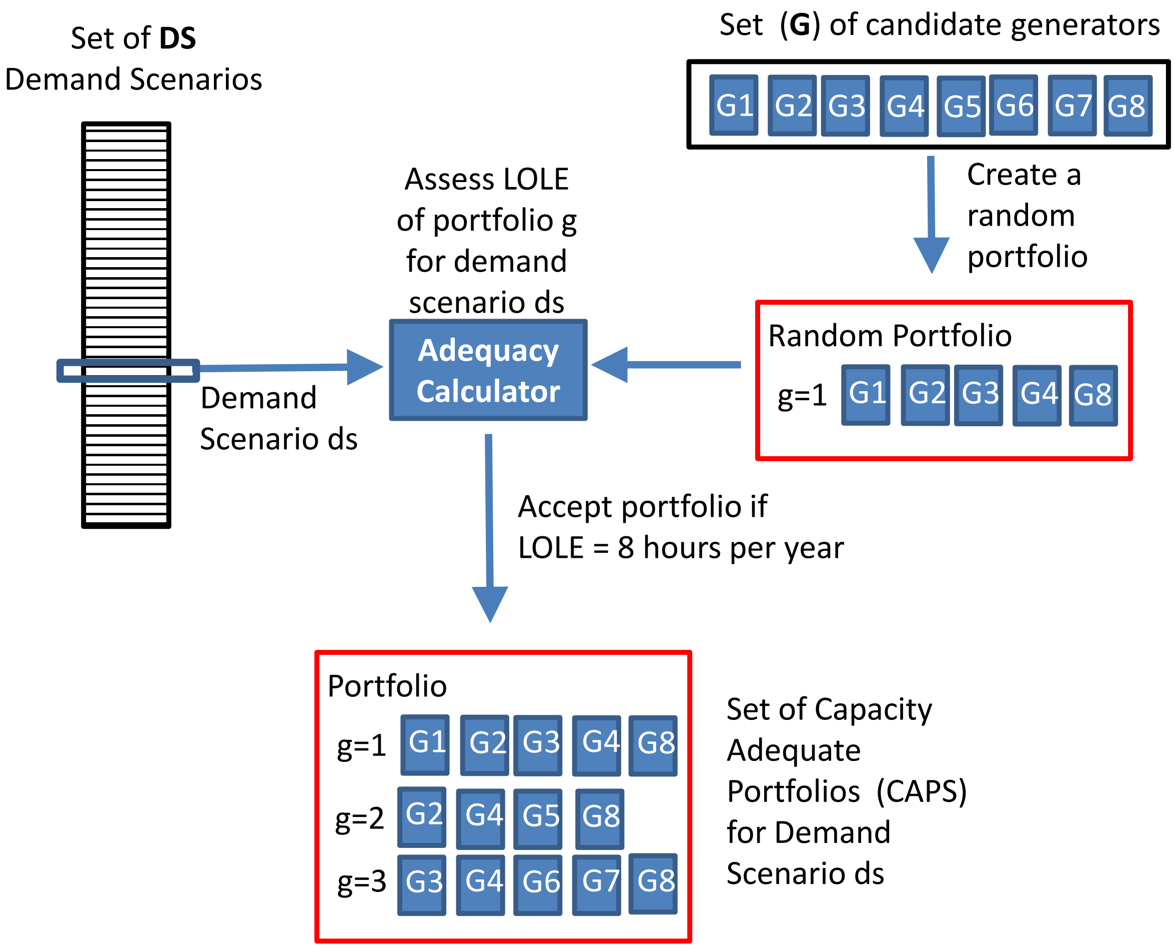

Figure 9: Determining Capacity Adequate Portfolios for each Demand Scenario

The starting point is a set (G) of capacity market units.[6] In this study this was the set of capacity market units that were operational as at 31 December 2015. For each capacity year generators that have indicated that they will have closed prior to that capacity year, as specified in GCS, are removed. It is important to understand that this set G only serves to provide a diverse set of representative capacity market units that can be drawn from in the analysis; the nature of a specific individual units in the set G has no material impact on the final de-ratings.[7]

For each demand scenario ds a set of randomly selected portfolios are each tested with an "adequacy calculator" that assesses the degree to which that portfolio achieves the LOLE standard of 8 hours per year. Those random portfolios that pass this test form the set of capacity adequate portfolios for that

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[6] For the purpose of the illustrations in this section we only show units – generators and demand-side units – within the set G that are to be de-rated, but other sources of supply such as interconnectors and non-market generation are accounted for and are assumed to contribute energy in serving demand.

[7] If the Set G of existing generators was capacity deficient then additional notional capacity would be added to the set to ensure that it could cover the requirements. This additional capacity would comprise a set of units with the properties of each category but of different sizes such that the aggregate pool of units has the same average availability as the existing generators.

demand scenario. The analysis produced 5 randomly generated capacity adequate portfolios per demand scenario. A capacity credit for wind is calculated for each of the demand scenarios using the approach described in section 6.2 and this capacity credit is used in the formation of the portfolios.

Figure 10 show how the Adequacy Calculator processes CAPs portfolio g given demand scenario ds. The hourly demand from demand scenario ds and how the scheduled outages and ambient outages are distributed across time are shown.

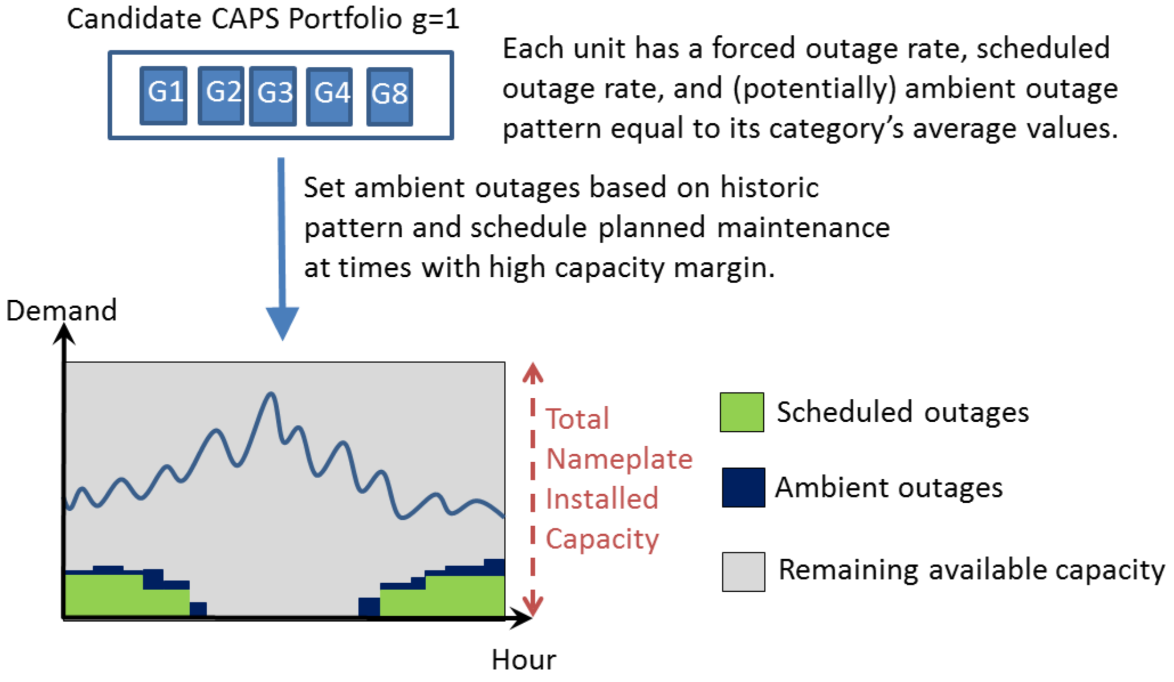

Figure 10: Allowing for ambient outages and scheduled outages in the Adequacy Calculator

The Adequacy Calculator schedules ambient outages are in months where they historically occur. These simply reduce the capacity available from individual generating units.

The Adequacy Calculator schedules when a unit undergoes a scheduled outage. The availability statistics imply the number of days per year that the unit is on scheduled outage. The scheduled outage for a unit occurs as one continuous outage (though the length of the outage is rounded to the nearest five days to reduce the complexity of the problem). The Adequacy Calculator schedules each outage at the time of the greatest surplus of available generation over demand given the outages already scheduled (i.e. maximises the minimum margin for each outage). Outages are scheduled in order of decreasing size (measured in terms of the product of unit size and outage duration). The grey shaded area indicates the remaining available installed capacity before forced outages are applied.

Scheduled outages do not significantly affect the de-rating factors, but the cumulative impact of the scheduled outages can affect the capacity requirement. It may be possible to further optimise the scheduling of outages within the calculation, but in the real system, scheduled outages are unlikely to align to this theoretically optimal schedule. There will be further testing of the outage scheduling approach during the consultation process.

This processing of ambient and scheduled outages leaves a set of available generating units in each hour with a capacity that has been adjusted for ambient effects and for scheduled outages.

The Adequacy Calculator then simulates forced outages of capacity market units independently for each individual hour to assess the level and probability of unserved load in that hour.[8]

For each hour there is a set of capacity market units that are not on scheduled outage and which have had their capacities adjusted for ambient outages. Each of these units has a forced outage rate, so given that scheduled and ambient outages have already been addressed, its expected availability is one less its forced outage rate.

The Adequacy Calculator determines the level of unserved energy for every permutation of forced outage that could occur in an hour. This allows a loss of load probability (LOLP) and Expected Unserved Energy (EUE) value to be determined for that hour. A detailed example of this is presented in the Appendix.

Repeating this process for each hour of the year in demand scenario ds gives the annual total LOLP and EUE for portfolio g. If the LOLE is within a set tolerance of the adequacy standard then the portfolio is accepted as capacity adequate.

6.2 Marginal De-Rating Process

The Marginal De-Rating process involves adding a single notional unit to a capacity adequate portfolio for a given demand scenario and determining the de-rating of the notional unit. The notional unit will have the outage statistics of one of the technology categories and will be of a specific MW capacity. To build up a curve of de-rating factors as a function of unit size for just one technology category it is necessarily to repeatedly solve this problem with notional units of different capacities. This process needs to be repeated independently for each technology category to build up a full set of curves.

Figure 11 shows how the de-rated capacity for a notional unit is deduced.

[8] This approach is based on established methods used in the production of the GCS. The European Network of Transmission System Operators - Electricity (ENTSO-E) is in the process of testing approaches that simulate the actual operation of the market within a dispatch model.

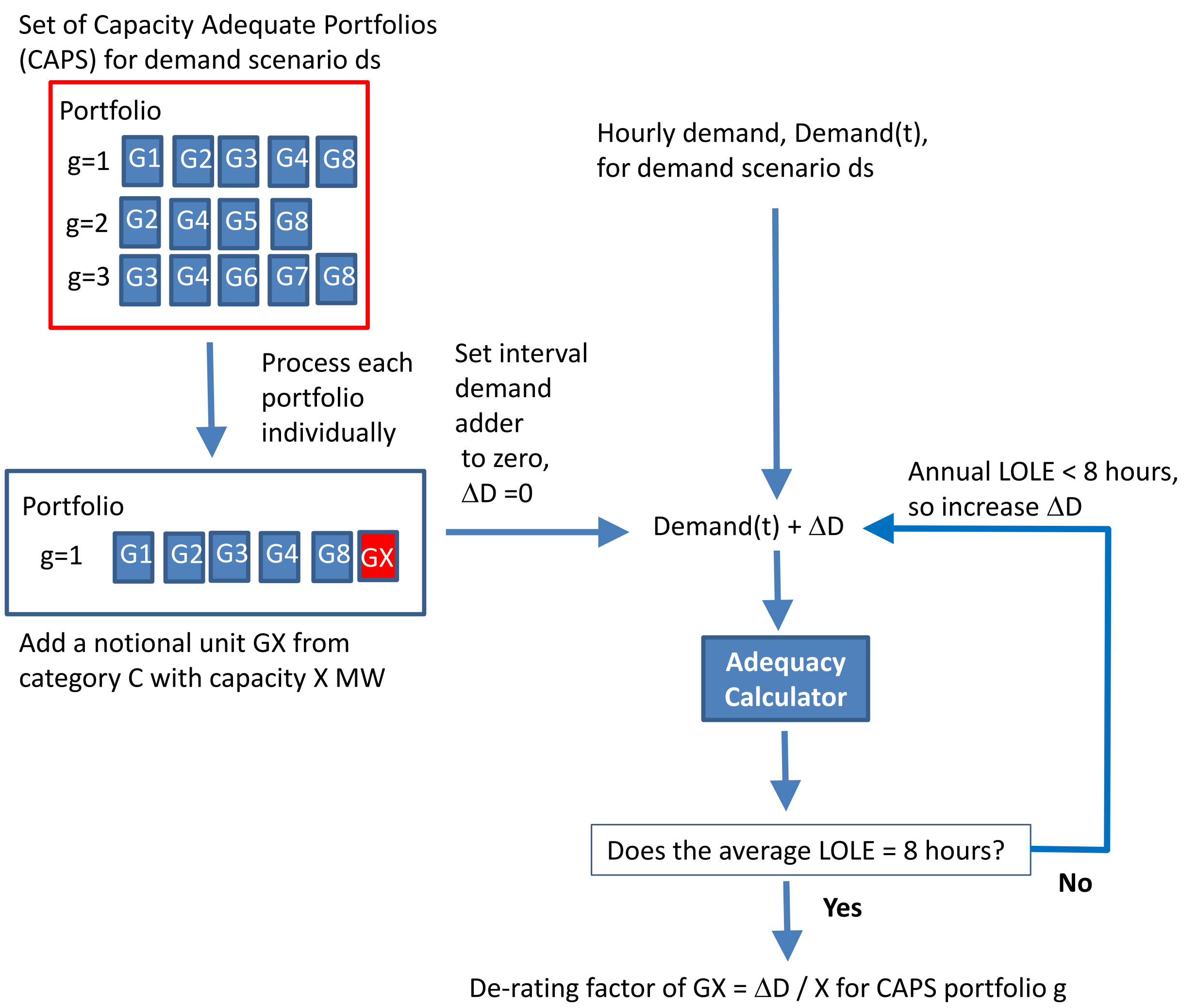

Figure 11: Schematic of the Marginal De-Rating Approach

The notional unit (GX) is added to each capacity adequate portfolio for demand scenario ds. Each updated portfolio is then processed individually. Figure 11 shows the processing of profile g=1. The Adequacy Calculator is run again but with the demand in all hours increased by some amount ΔD. With $\Delta D = 0$ the demand is exactly the demand against which the original portfolio g=1 satisfied the 8 hour LOLE Standard. With the additional capacity of unit GX the portfolio will now give an LOLE of less than 8 hours. The value of ΔD is increased until the LOLE of the new portfolio equals 8 hours again. The de-rating factor of unit GX is then defined as the ratio of ΔD to the capacity X of unit GX.

If unit GX is totally reliable then the LOLE will rise to 8 hours only when ΔD=X and the de-rating factor will be 1. This means that the de-rated capacity of GX will be its installed capacity of X. However, if GX is less reliable then the de-rating factor will be less than 1.

By repeating this process for each technology category and by varying the capacity of unit GX it is possible to determine a set of de-rated availabilities for any unit of any size belonging to a category.

The de-rating factor for wind is calculated by the same process as outlined above. The change in surplus caused by adding/removing the wind generation profile to the portfolio is calculated for each demand-wind profile pair (using eight annual profiles in the current analysis). These changes in the surplus are then divided by the total installed capacity of wind to give a de-rating factor for each demand-wind profile pair. In the current analysis, the final de-rating factor for wind is given as the average of these de-rating factors.

It is expected that the de-rating factors curves will be applied to the lesser of the registered capacity of the generating unit and the maximum export capacity specified in the connection agreement. For example, for an autoproducer the de-rating factor would be applied to its maximum export capacity and not to its installed capacity.

The marginal de-rating of storage units is complex as both the storage and generation component can vary in size. For the indicative results presented in this document the marginal de-rating approach to storage is specific to the existing pumped storage unit in the SEM. The generation component is treated as a load modifier (i.e. it reduces the peak demand until the associated reservoir is depleted). Further work will be required during the consultation process to finalise the marginal de-rating approach to storage.

6.3 Determining the De-Rated Capacity Requirements for each Demand Scenario

The process described thus far produces for a given demand scenario:

- A set of capacity adequate portfolios, each having:
    - A curve of de-rating factors as a function of unit size for each technology category.

By applying the de-rating curves to each unit within a capacity adequate portfolio we can deduce the de-rated capacities for those units. The de-rated capacity requirement for that portfolio is set to the sum of these unit de-rated capacities.

For each demand scenario, a different de-rated capacity requirement will be determined for each capacity adequate portfolio. Only the capacity adequate portfolio with the largest de-rated capacity requirement can be sure of satisfying the LOLE standard for any combination of potential portfolios that could result from an auction. In consequence, the De-rated capacity requirement for a demand scenario will be set to the largest de-rated capacity requirement for any capacity adequate portfolio produced for that scenario. While lower choices for the de-rated capacity requirement may still satisfy the LOLE standard for some mix of units, there is no guarantee that the auction will produce that mix of units.

For each demand scenario, a different set of de-rating factor curves will also be generated for each capacity adequate portfolio. The methodology defines a single set of de-rating curves for each demand scenario, with the de-rating factor for a unit of a given MW size and technology being the average de-rating factor across all capacity adequate portfolios for that demand scenario for a unit of that size and technology.

Part D - Final Scenario Selection

7 Selecting the Capacity Requirement and De-rating Factors to be used for Qualification

7.1 Selection of the Optimal Demand Scenario

The analysis thus far has determined capacity adequate profiles for each demand scenario and has determined a de-rated capacity requirement and de-rating curves for each demand scenario. However, we do not know which demand scenario will actually transpire.

If the de-rated capacity requirement for the lowest demand scenario is implemented then the capacity adequate portfolios associated with it may fall significantly short of meeting the 8 hour LOLE standard if the highest demand scenario actually occurs. This could result in load shedding at times where there is inadequate capacity to serve the higher than expected demand. The cost of each unit of shortage is equal to the Value of Lost Load. Hence the market faces a high cost if it fails to procure enough capacity.

If the de-rated capacity requirement for the highest demand scenario is implemented then the capacity adequate portfolios associated with it may significantly exceed the 8 hour LOLE standard if the lowest demand scenario actually occurs. The market would have paid for capacity which it turns out not to require. Hence the market faces a high cost in the form of idle capacity that must be funded by the capacity auction.

The SEM Committee has decided that a Least-Worst Regrets approach should be used to find a de-rated capacity requirement that seeks to minimise the combined cost of over-procuring capacity and incurring high demand curtailment costs (beyond those implied by the LOLE standard).

7.2 Description of the Least-Worst Regrets Analysis

Figure 12 illustrates the scenarios of capacity shortfall and capacity surplus that can arise if the de-rated capacity requirement is set based on demand scenario ds when a different demand scenario k occurs.

To perform this analysis, it is necessary to determine for each demand scenario:

- The excess expected unserved energy beyond the 8 hour standard if another demand scenario occurs.
- The capacity surplus, being the amount by which the de-rated capacity requirement for the demand scenario exceeds the capacity required if another demand scenario occurs.

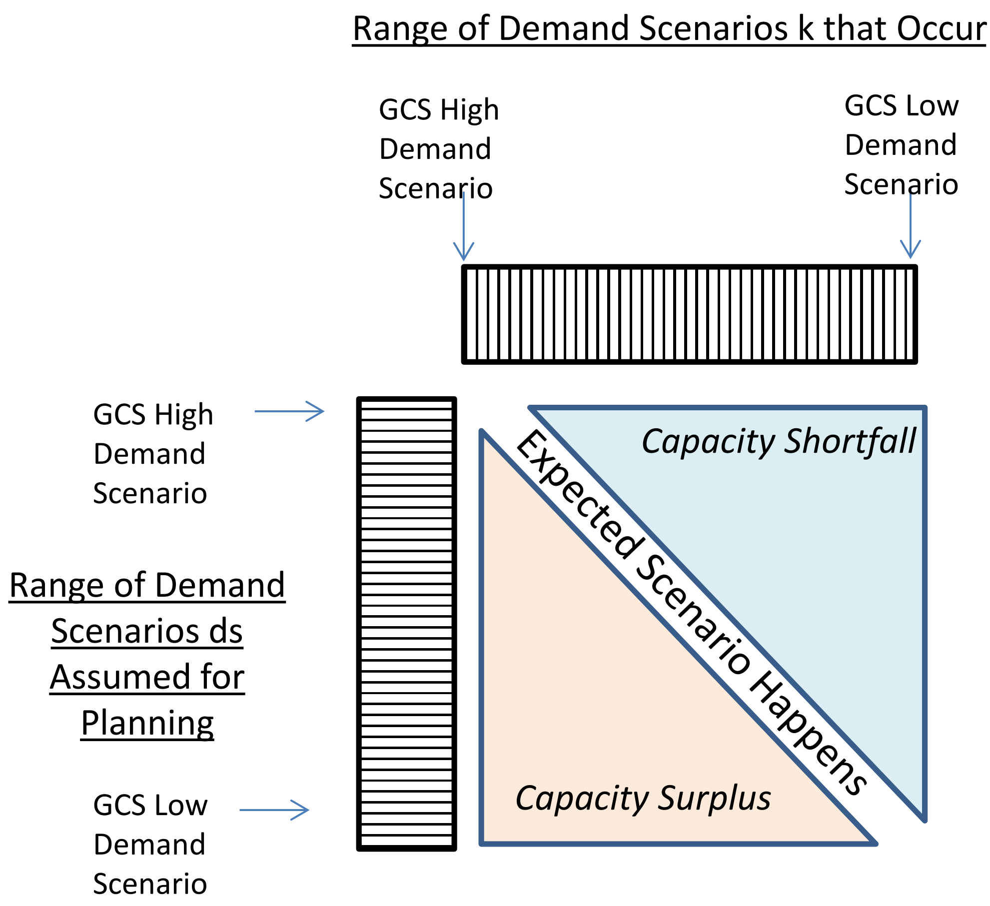

Figure 12: Least-Worst Regrets Analysis

Figure 14 illustrates the process for determining the excess EUE for each combination of demand scenarios. Each capacity adequate portfolio for demand scenario ds is simulated with the Adequacy Calculator for every demand scenario k in the set of demand scenarios DS. In each case the EUE value is determined.[9] However, as some unserved energy would have occurred if demand scenario ds had applied, we must subtract this EUE to get the excess EUE.

Unserved energy in the I-SEM is priced at the Value of Lost Load. Averaging the excess EUE across all the capacity adequate portfolios for demand scenario ds and multiplying this average by the Value of Lost Load (VoLL) places a value on the Regret Cost of Capacity Shortfall for demand scenario ds if demand scenario k occurs.

[9] While it may seem intuitive that the EUE value should only increase for demand scenarios with higher forecast demand than demand scenario k, this is not necessarily the case. How demand is profiled across the year can differ between demand scenarios and these different profiles can result in an increased EUE even if the peak demand does not exceed that in the base demand scenario k.

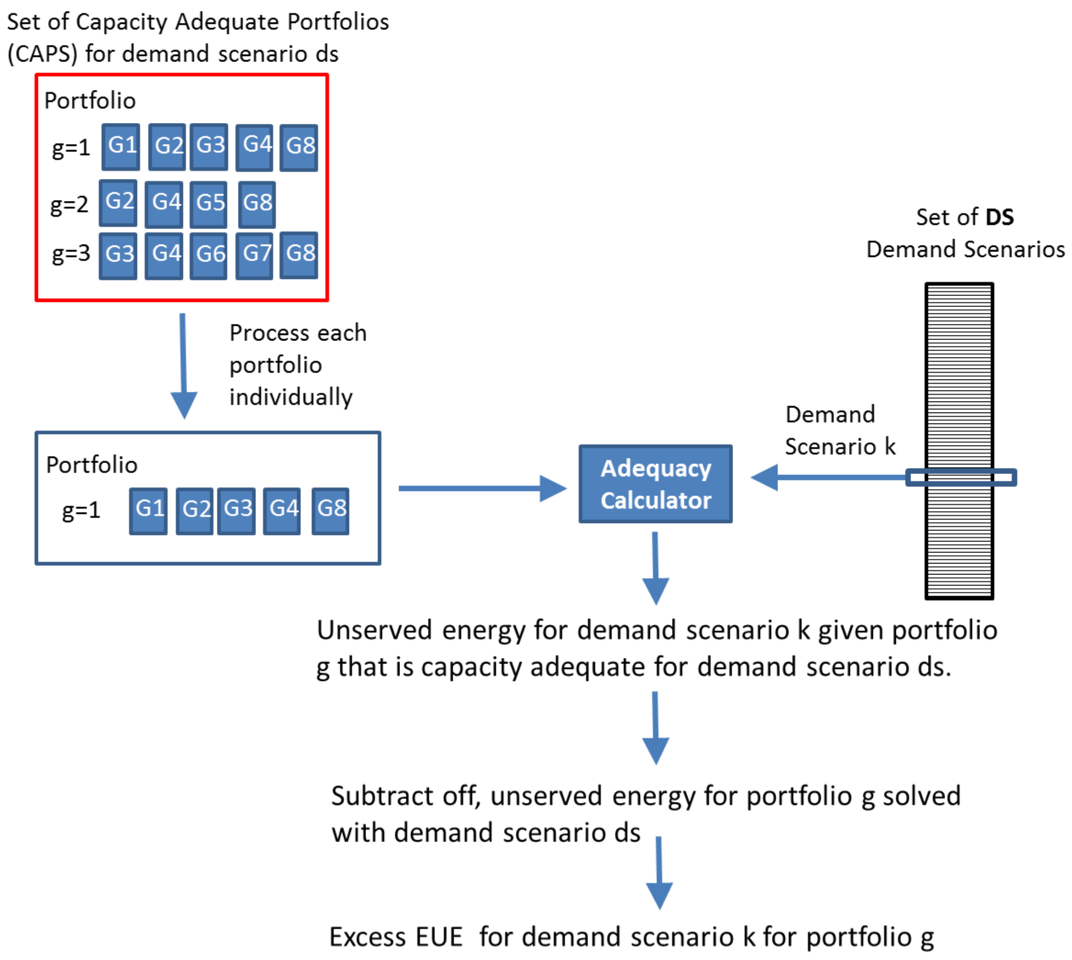

Figure 13: Determination of the annual EUE for each alternative demand scenario that could occur

The de-rated capacity requirement for each demand scenario ds is defined in section 6. If demand scenario k occurs, and corresponds to a lower capacity requirement then the amount of surplus capacity procured is the difference between the de-rated capacity requirements for these demand scenarios. This capacity is assumed to be priced at the price of the best new entrant (BNE). In the absence of a Net CONE value for the current analysis the current proposed BNE value[10] is used. Multiplying the BNE by the surplus capacity places a value on the Regret Cost of Capacity Surplus for demand scenario ds if demand scenario k occurs.

The key final step in this analysis is to identify the preferred demand scenario, i.e. the demand scenario that defines the de-rated capacity requirement and de-rating factors resulting from this analysis. Under the least-worst regrets approach the selected demand scenario is that for which the sum of the Regret Cost of Capacity Surplus and the Regret Cost of Capacity Shortfall is lower than for any other demand scenario.

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[10] https://www.semcommittee.com/news-centre/fixed-cost-bne-peaking-plant-capacity-requirement-and-acps-2017-consultation-published

The following gives an illustrative example of the least-worst regrets analysis. Note that these are for illustrative purposes only and are not the values used for the indicative results given in Section 9.

7.3 Illustrative Example of Least-Worst Regrets Analysis

The example uses 5 demand forecasts and 3 demand profiles (giving a total of 15 demand scenarios). As outlined above there are 3 main steps to the least-worst regrets analysis.

Step 1: Calculate Regret Cost of Excess Capacity

If the outturn demand is lower than that in the scenario being evaluated, using that scenario would lead to the purchase of more capacity than is required. The regret costs are calculated by multiplying the excess capacity MW value by net-CONE (or in this case BNE) and are given in figure 14.

Scenario	F1P1	F1P2	F1P3	F2P1	F2P2	F2P3	F3P1	F3P2	F3P3	F4P1	F4P2	F4P3	F5P1	F5P2	F5P3
F1P1 - 6754 MW	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0
F1P2 - 6766 MW	1	0	4	0	0	0	0	0	0	0	0	0	0	0	0
F1P3 - 6715 MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
F2P1 - 6848 MW	7	6	10	0	0	2	0	0	0	0	0	0	0	0	0
F2P2 - 6864 MW	8	7	11	1	0	3	0	0	0	0	0	0	0	0	0
F2P3 - 6826 MW	5	4	8	0	0	0	0	0	0	0	0	0	0	0	0
F3P1 - 6944 MW	14	13	17	7	6	9	0	0	2	0	0	0	0	0	0
F3P2 - 6973 MW	16	15	19	9	8	11	2	0	5	0	0	0	0	0	0
F3P3 - 6911 MW	11	11	14	5	3	6	0	0	0	0	0	0	0	0	0
F4P1 - 7065 MW	23	22	25	16	15	17	9	7	11	0	0	4	0	0	0
F4P2 - 7088 MW	24	23	27	17	16	19	10	8	13	2	0	5	0	0	0
F4P3 - 7013 MW	19	18	22	12	11	14	5	3	7	0	0	0	0	0	0
F5P1 - 7151 MW	29	28	32	22	21	24	15	13	17	6	5	10	0	0	2
F5P2 - 7196 MW	32	31	35	25	24	27	18	16	21	10	8	13	3	0	5
F5P3 - 7124 MW	27	26	30	20	19	22	13	11	16	4	3	8	0	0	0

Figure 14: Regret cost of excess capacity (values in € millions)

Step 2: Calculate Regret Cost of excess EUE (too little capacity):

If the outturn demand is higher than that in the scenario being evaluated, using that scenario would lead to the purchase of less capacity than is required. This, in turn would increase the MWh level of expected unserved energy. The regret costs are calculated by multiplying the excess expected unserved energy MWh value by VoLL and are given in figure 15.

Scenario	F1P1	F1P2	F1P3	F2P1	F2P2	F2P3	F3P1	F3P2	F3P3	F4P1	F4P2	F4P3	F5P1	F5P2	F5P3
F1P1 - 6754 MW	0	3	0	11	15	6	28	35	20	52	64	41	88	106	72
F1P2 - 6766 MW	0	0	0	8	11	3	22	28	16	44	54	34	77	92	62
F1P3 - 6715 MW	4	7	0	17	22	11	37	45	28	66	79	52	108	129	88
F2P1 - 6848 MW	0	0	0	0	3	0	11	15	6	28	35	20	52	63	41
F2P2 - 6864 MW	0	0	0	0	0	0	8	11	3	22	28	16	44	54	34
F2P3 - 6826 MW	0	0	0	4	7	0	17	22	11	36	45	27	65	78	52
F3P1 - 6944 MW	0	0	0	0	0	0	0	2	0	11	15	6	28	35	20
F3P2 - 6973 MW	0	0	0	0	0	0	0	0	0	8	11	3	22	28	16
F3P3 - 6911 MW	0	0	0	0	0	0	4	7	0	17	22	11	36	45	28
F4P1 - 7065 MW	0	0	0	0	0	0	0	0	0	0	3	0	11	15	6
F4P2 - 7088 MW	0	0	0	0	0	0	0	0	0	0	0	0	7	11	3
F4P3 - 7013 MW	0	0	0	0	0	0	0	0	0	4	7	0	17	22	11
F5P1 - 7151 MW	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0
F5P2 - 7196 MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
F5P3 - 7124 MW	0	0	0	0	0	0	0	0	0	0	0	0	4	7	0

Figure 15: Regret cost of excess EUE (values in € millions)

Step 3: Calculate total regret cost and select the Least Worst Regret:

The two components of regret cost are summed and combined into a single table, and the worst regret cost for each is determined. The scenario that has the lowest worst regret cost is selected as being the optimal scenario for the auction. In this instance it is the capacity requirement that is associated with demand forecast 4 and demand profile 3.

Scenario	F1P1	F1P2	F1P3	F2P1	F2P2	F2P3	F3P1	F3P2	F3P3	F4P1	F4P2	F4P3	F5P1	F5P2	F5P3	Max Regret	Least-Worst Regret
F1P1 - 6754 MW	0	3	3	11	15	6	28	35	20	52	64	41	88	106	72	106	
F1P2 - 6766 MW	1	0	4	8	11	3	22	28	16	44	54	34	77	92	62	92	
F1P3 - 6715 MW	4	7	0	17	22	11	37	45	28	66	79	52	108	129	88	129	
F2P1 - 6848 MW	7	6	10	0	3	2	11	15	6	28	35	20	52	63	41	63	
F2P2 - 6864 MW	8	7	11	1	0	3	8	11	3	22	28	16	44	54	34	54	
F2P3 - 6826 MW	5	4	8	4	7	0	17	22	11	36	45	27	65	78	52	78	
F3P1 - 6944 MW	14	13	17	7	6	9	0	2	2	11	15	6	28	35	20	35	
F3P2 - 6973 MW	16	15	19	9	8	11	2	0	5	8	11	3	22	28	16	28	
F3P3 - 6911 MW	11	11	14	5	3	6	4	7	0	17	22	11	36	45	28	45	
F4P1 - 7065 MW	23	22	25	16	15	17	9	7	11	0	3	4	11	15	6	25	
F4P2 - 7088 MW	24	23	27	17	16	19	10	8	13	2	0	5	7	11	3	27	
F4P3 - 7013 MW	19	18	22	12	11	14	5	3	7	4	7	0	17	22	11	22	22
F5P1 - 7151 MW	29	28	32	22	21	24	15	13	17	6	5	10	0	3	2	32	
F5P2 - 7196 MW	32	31	35	25	24	27	18	16	21	10	8	13	3	0	5	35	
F5P3 - 7124 MW	27	26	30	20	19	22	13	11	16	4	3	8	4	7	0	30	

Figure 16: Total regret cost, worst regret for each scenario and least-worst regret cost (values in € millions)

The analysis highlights that significant under procurement leads to higher costs than the same level of over-procurement. This results in the selected demand scenario tending towards the high demand forecast.

8 Process

Once a methodology and set of results is determined for the first auctions, there is a question of how frequently the de-rating factors are updated (e.g. annual, every two or three years).

9 Indicative Results

Please note that these values are indicative and have been calculated using a test version of the analysis tools.

9.1 Indicative De-rating Factors

The following table contains indicative de-rating factors for the different technology categories and sizes calculated using the test version of the analysis tools. Here, the size classes are divided into 100 MW divisions. The midway point in the size class is used to calculate the de-rating factor to be applied to that size class. The merits and feasibility of using smaller size divisions will be tested further. However, given the current limitations of the analysis tools this is considered to be the most appropriate and feasible size division.

Marginal de-rating factors have been calculated for the interconnectors using the indicative results of the RA Interconnector de-rating methodology (described in the accompanying paper to this report). These are a forced outage rate of 6% and a scheduled outage rate of 2.25% and Effective Interconnector

Capacities of 392 MW and 435 MW for Moyle and EWIC, respectively. These are then treated the same as other technology types in the marginal de-rating process. The differences between the marginal de-rating factors for Moyle and EWIC is due to the fact that they fall into two different size classes.

De-rating Factors (%)								
Size Class (MW)	Gas Turbine	Steam Turbine	Hydro	Storage	DSU	Wind	EWIC	Moyle
001-100	95.8	91.8	95.4	86.0	73.0	12.5	85.6	88.0
101-200	95.0	90.3	94.6	82.7	68.8			
200-300	94.0	88.3	93.4	74.4	64.1			
301-400	92.6	85.9	92.0	64.3	59.3			
401-500	91.1	83.1	90.3	54.2	54.4			

Table 4: Indicative de-ratings for different technology categories and size classes

9.2 Indicative Capacity Requirements

The table below gives the indicative capacity requirements that have been calculated using the test version of the analysis tools for the 2017/18 to 2020/21 capacity years. These values represent the forecasted capacity requirement to satisfy the 8hr LOLE adequacy standard for the unconstrained all-island system.

	2017	2018	2019	2020
Indicative Capacity Requirement	7,312	7,321	7,401	7,498

Table 5: Indicative Capacity Requirements for 2017/18 to 2020/21

The question may be asked as to how the indicative capacity requirements presented here compare to the capacity requirement that is calculated for the current capacity payment mechanism (CPM). The proposed methodology determines a de-rated capacity requirement whereas the CPM uses an installed capacity requirement. As such, in order to compare the two, it is necessary to convert the indicative figures included above into an installed capacity requirement. To enable this, we have estimated the level of installed capacity that would be required to satisfy the indicative de-rated capacity requirement set out above for 2017/18. This is estimated by finding the average total installed capacity for capacity adequate portfolios that correspond to the chosen demand scenario and results in a value of 8,012 MW. The current value for the CPM for 2017 is 7,267 MW, which leaves a difference of 745 MW.

There are a number of reasons why the two values would be different including:

- This methodology includes a provision for reserve whereas the CPM does not. This is the most significant and accounts for approximately two thirds of the difference.
- This methodology uses a range of demand forecasts and allows the least worst regrets analysis to select the preferred demand scenario whereas the CPM uses the median demand forecast.
- This methodology uses multiple matching wind and demand profile pairs whereas the CPM uses one matching pair.
- The two methodologies use different techniques for calculating and applying outage statistics.
- This methodology is based on the capacity year whereas the CPM is based on calendar year.

The first three differences above reflect the emerging approaches to adequacy assessment and capacity requirements being considered at a European level through ENTSO-E and the need to consider the increasingly dynamic nature of the power system in establishing a capacity requirement. The final two reflect changes that relate more to the design of the new arrangements (e.g. the calculation of marginal de-rating factors based on technology class and size). It should also be noted that whereas the differences due to the inclusion of reserve with the demand results in a larger capacity requirement, the other factors can serve to increase or decrease the capacity requirement.

10 Operational Considerations

The indicative de-rated capacity requirements presented in this document reflect the aggregate de-rated capacity required to satisfy the unconstrained All-Island LOLE adequacy standard. This approach treats all de-rated capacity as equivalent and makes no allowance for network considerations, such as ensuring that there is adequate capacity available in specific regions allowing for transmission limitations and the risk of transmission outages impacting on available generation.

It is possible therefore that the loss of load expectation could be higher than predicted if the theoretically available capacity from a portfolio of generators cannot be delivered due to transmission or security limitations. These situations cannot be resolved simply by increasing the capacity requirement without consideration of where that capacity is located. In the market today, the power system may have significantly more capacity than is theoretically required to meet peak demand, but operationally situations do arise where combinations of planned outages and transmission limitations can mean that the supply and demand situation in specific regions is very tight.

It follows that a CRM auction result that satisfies the de-rated capacity requirement will not necessarily allow the TSOs to operate the power system within its operational limits while still satisfying the LOLE standard.

The RAs are seeking to address locational issues in another consultation that is due to be published on the 23rd of August 2016. The TSOs agree that further consideration should be given to the management of locational issues, both with respect to longer term operation of the CRM and during the transitional period.

11 Glossary

Terminology	Meaning
Adequacy Calculator	A process that determines the LOLE associated with a demand scenario and a portfolio of units.
Auction Capacity Requirement	The aggregate de-rated capacity targeted to be supplied from generating units and demand side units in the capacity auction.
Capacity Market Unit	One or more generating units or demand side units eligible to participate in the capacity auction.
Capacity Year	A 12-month period commencing 1 October and associated with a de-rated capacity requirement.
Demand Forecast	A level of forecast demand for a year, comprising a peak value (MW) and a cumulative value (MWh). This includes transmission and distribution losses and is net of generation on the demand site that is not separately metered.
Demand Profile	An hourly set of MWh demand levels for a historic year. This includes transmission and distribution losses and is net of generation on the demand site that is not separately metered.
Demand Scenario	An hourly set of MWh demand levels, net of embedded generation, derived from a demand forecast and a net demand profile such as to produce the same peak and annual consumption as the demand forecast. A reserve level to cover the largest single infeed is then applied.
De-Rated Capacity	The capacity expected to be available from a capacity market unit after allowing for forced, scheduled and ambient outages.
De-rated capacity requirement	The aggregate de-rated capacity targeted to be supplied from generating units and demand side units required to satisfy the LOLE Standard
De-Rating Factor	The proportion of a unit's capacity that is deemed to be capable to contribute to the Capacity Requirement
Expected Unserved Energy (EUE)	The LOLP probability weighted level of unserved energy. This may be calculated by hour or accumulated over a year.
Generation Capacity Statement (GCS)	An annual EirGrid and SONI planning report projecting future All Island demand growth and system capacity adequacy.
LOLE Standard	This is the level of LOLE required to be satisfied by the de-rated capacity requirement. It is set to 8 hours per year.
Loss of Load Expectation (LOLE)	The accumulative total LOLP for a year to give the expected number of hours per year in which there is inadequate capacity to meet demand.

Loss of Load Probability (LOLP)	The probability that there is inadequate capacity to meet demand for an hour.
Portfolio	A set of generating units and demand side units that represent those available in the I-SEM at a particular time and which are eligible for inclusion in the auction.
Qualification	A process for qualifying a generating unit, demand side unit or interconnector for participation in a capacity auction.
Technology Classes	Groupings of generator and demand-side unit technologies used for the purposes of averaging availability data

Appendix I - LOLP Example

This appendix presents an example of how the Adequacy Calculator determines the loss of load probability and expected unserved energy for an hour.

Suppose that from portfolio g=1 only units G1, G2 and G8 were available in a given hour *t* and had the properties in Table 6. The demand in hour *t* is 160 MWh.

Unit	Available Capacity (MW)[11]	Forced Outage Rate	Probability Unit Available
G1	200	0.05	0.95
G2	100	0.15	0.85
G8	50	0.10	0.90

Table 6: Example unit data

If all three units are available, they have a combined capacity of 350 MW. The probability of this occurring is the product of the probabilities of each unit being available, or 0.95×0.85×0.90=0.72675. There is no shortage as the available capacity far exceeds the demand.

The Adequacy Calculator assesses every permutation of potential generator availabilities. For example, if only G2 and G8 are available there is only 150 MW of capacity in service. This implies a shortage of 10 MW. The probability of this occurring is the probability that G1 has had a forced outage (0.05) multiplied by the probability that G2 and G8 are available (0.85×0.90). This outcome occurs with a probability of 0.03825. The expected unserved energy is 10 MW × 0.03825 = 0.3825 MW.

In Service	Capacity (MW)	Probability	Shortage (MWh)	LOLP	EUE (MWh)
G1, G2, G8	350	0.95×0.85×0.90=0.72675	0	0	0
G1, G2	300	0.95×0.85×0.10=0.08075	0	0	0
G1, G8	250	0.95×0.15×0.90=0.12825	0	0	0
G1	200	0.95×0.15×0.10=0.01425	0	0	0
G2, G8	150	0.05×0.85×0.90=0.03825	10	0.03825	0.3825
G2	100	0.05×0.85×0.10=0.00425	60	0.00425	0.255
G8	50	0.05×0.15×0.90=0.00675	110	0.00675	0.7425
None	0	0.05×0.15×0.10=0.00075	160	0.00075	0.12
Total		**1.0000**		**0.0500**	**1.5000**

Table 7: Determining LOLP

[11] After allowing for ambient outages and scheduled outages

Table 7 shows all the potential states of these three generators, the capacity available in that state, the probability of that state, and the level of shortage if any. The LOLP is the sum of the probabilities of all states with shortage while the Expected Unserved Energy (EUE) is the expected volume of energy curtailed determined as the LOLP multiplied by the shortage. This shows that for this single hour t the LOLP is 0.05 and EUE is 1.5 MWh.