ROBINSON BOWMAKER PAUL

AUSTRALIAN ENERGY MARKET OPERATOR

FINAL REPORT: ASSESSMENT OF SYSTEM RELIABILITY (EXPECTED UNSERVED ENERGY) AND DEVELOPMENT OF THE AVAILABILITY CURVE FOR THE SOUTH WEST INTERCONNECTED SYSTEM

1 JUNE 2017

Prepared by: Richard Bowmaker, Sue Paul

Document version: FINAL 4.0

Robinson Bowmaker Paul
Level 8, 104 The Terrace
Wellington 6011
New Zealand
www.robinsonbowmakerpaul.com

CONTENTS

1 - Executive Summary

Australian Energy Market Operator (AEMO) has engaged Robinson Bowmaker Paul (RBP) to:

- Undertake the Reliability Assessment and Development of the Availability Curve for the Southwest Interconnected System (SWIS)
- Forecast the Expected DSM Dispatch Quantity (EDDQ) in accordance with WEM Market Rule (MR) 4.5.14A and the Market Procedure: Determination of the Expected DSM Dispatch Quantity and the DSM Activation Price.

This report contains the details and results of our analysis.

1.1 Context

AEMO is responsible for operating a Reserve Capacity Mechanism to ensure that adequate supply is available over the long term. To assess the amount of reserve capacity that will be required the AEMO undertakes a Long-term Projected Assessment of System Adequacy (LT PASA). The results of the LT PASA analysis feed into the AEMO's Statement of Opportunities (SOO) report which forecasts:

- The Reserve Capacity Target (MR 4.5.10(b)) for each year in the LT PASA study and the reserve capacity requirement (MR 4.6.1). The Reserve Capacity Target is set so as to meet the Planning Criterion which is defined in MR 4.5.9. The Planning Criterion comprises two components:
  - A forecast peak component to ensure that adequate supply is available to meet a one in ten-year peak (MR 4.5.9(a)) and
  - A reliability component to ensure expected energy shortfalls are limited to 0.002% of annual demand (MR 4.5.9(b)).
- Generation capacity and Demand Side Management (DSM) requirements in the form of the Availability Curve, which is defined by MR 4.5.12.

Additionally, MR 4.5.14A and 4.5.13(h) require AEMO to calculate and publish the Expected DSM Dispatch Quantity (EDDQ) for each Capacity Year in the LT PASA study.

The purpose of this report is to:

- Undertake a Reliability Assessment to ensure the Reserve Capacity Target is compliant with MR 4.5.9(b) and
- Develop the Availability Curve defined by MR 4.5.12.
- Forecast the EDDQ defined by MR 4.5.14A

1.2 Scope of work

We have:

- Undertaken the Reliability Assessment for two Reserve Capacity Cycles:
  - The 2016 Reserve Capacity Cycle covering Capacity Years 2016/17 to 2025/26
  - The 2017 Reserve Capacity Cycle covering Capacity Years 2017/18 to 2026/27
- Calculated the Availability Curve for the second and third year of each Reserve Capacity Cycle:
  - This covers 2017/18 and 2018/19 for the 2016 Reserve Capacity Cycle
  - This covers 2018/19 and 2019/20 for the 2017 Reserve Capacity Cycle
- Forecasted the EDDQ for the ten years comprising the LT PASA study for the 2017 Reserve Capacity Cycle (2017/18 to 2026/27).

1.3 Methodology

There are four main components to the analysis undertaken in this report as follows:

- Developing forecasted load duration curves (LDC) for each year in the LT PASA horizon (given a 50% POE peak forecast and an annual demand forecast)
- Performing the Reliability Assessment by undertaking probabilistic simulations of the Wholesale Electricity Market
- Developing the Availability Curve
- Forecasting the EDDQ

Each component is described further below.

1.3.1 Development of Load Profiles

Hourly load profiles (or LDCs) were forecasted by:

- First developing a base-year load duration curve averaging historical data over the past five years and
- Second, scaling the base year load profile up to match both the 50% peak forecast and the total expected demand in each year.

For more details on our load development methodology refer to Section 2.2.

1.3.2 Reliability Assessment

The Reliability Assessment was undertaken using a combination of fundamental market modelling and Monte Carlo analysis.

In brief, using the forecasted load profiles developed above, the Wholesale Electricity Market was simulated (using random load and forced outages). The probabilistic simulations were then used to derive the expected unserved energy (EUE), and to check that the EUE was less than or equal to 0.002% as a proportion of annual demand (as required by **MR 4.5.9(b)**).

For more details on our market modelling methodology refer to Section 2.3.

1.3.3 Availability Curve

The Availability Curve was developed in three phases as per **MR 4.5.10(e)**, **MR 4.5.12(b)** and **MR 4.5.12(c)** by:

- Developing a two-dimensional duration curve of the forecast minimum capacity requirements (**MR 4.5.10(e)**). This was undertaken by scaling the base year load profile up to the relevant forecast peak and demand quantity (consistent with **MR 4.5.10(e)(i)**), and then adding the Reserve Margin and Load Following Ancillary Services requirement (as required by **MR 4.5.10(e)(ii)**).
- Forecasting the minimum capacity (Availability Class 1) required such that if all available DSM (Availability Class 2) were activated and System Management's outage evaluation criteria (as defined in **MR 3.18.11**) were to apply, then the Planning Criterion would still be met (**MR**

4.5.12(b)). This was undertaken by repeating the modelling exercise described above with four differences:

- First, DSM is modelled in greater detail to take into account the constraints around the availability of DSM facilities. We have allocated DSM throughout the year using an optimisation model that dispatches DSM so as to minimise the peak and subject to scheduling and availability constraints. See Section 2.4.1 for further details on our approach to modelling DSM.
- Second, we have specified a Reserve Requirement of 520 MW[1] in the market model to represent the Ancillary Services requirement of **MR 3.18.11(a)**. This will ensure that there is always a capacity margin of 520 MW in any given hour.
- Third, forced outages are taken out of the model, and the only stochastic component of the simulation is random load. The reason for the removal of forced outages is that the specification of a 520 MW reserve requirement on top of forced outages effectively over-estimates the capacity margin. The purpose of the 520 MW margin is to cover unforeseen events such as forced outages. As such, if there were a forced outage in a given period, the operating reserve would be used to generate to prevent unserved energy. Hence, including forced outages ***and*** maintaining the 520 MW capacity margin (for reserve only) could lead to expected unserved energy exceeding 0.002% of annual demand.
- Finally, for each year of the relevant Reserve Capacity Cycle, we iterated the model so as to reallocate the amount of DSM and generating capacity (keeping the total capacity capped at the Reserve Capacity Target level) until the EUE requirement in **MR 4.5.9(b)** was violated.
- The level of generation capacity at which the EUE equals 0.002% of expected demand sets the *minimum capacity* prescribed in **MR 4.5.12(b)**.

* Deriving the capacity associated with Availability Class 2 (as defined in **MR 4.5.12(c)**).

For more details on the development of the Availability Curve refer to Section 2.4.

1.3.4 EDDQ

We have forecasted the EDDQ using the following approach:

---

[1] Source: AEMO.

1. **Forecast Expected Unserved Energy when DSM is dispatched for zero hours ($EUE_{t,0}$)**. This involves repeating the Reliability Assessment as described in Section 2.3 but setting the available capacity of all DSM facilities to zero. Hence, only generation capacity is available to meet demand as described in **MR 4.5.14C(a)**.
2. **Forecast Expected Unserved Energy when DSM is dispatched for 200 hours ($EUE_{t,200}$)**. This involves repeating the Step 1 above but with the forecasted LDC adjusted to take into account DSM dispatch for exactly 200 hours. The optimised DSM dispatch is deducted off the forecasted LDC, and it is this adjusted LDC that becomes an input into the market model. Hence, generation capacity plus exactly 200 hours of DSM dispatch is available to meet demand as described in MR 4.5.14C(b).
3. Calculate EDDQ in year t as follows:

$$EDDQ_t = \frac{EUE_{t,0} - EUE_{t,200}}{Expected\ DSM\ Capacity\ Credits_t}.$$

1.4 Results

1.4.1 Reliability Assessment

The Reliability Assessment indicated that for all years of the LT PASA forecast horizon (2016/17 to 2026/27) the Reserve Capacity Targets will be set by the forecast peak quantity determined by **MR 4.5.9(a)**.

The EUE as a percentage of annual demand when total capacity is capped at the forecast peak component given by **MR 4.5.9(a)** (first column) is summarised in Table 1. Here we see that the peak forecast component is sufficient to limit expected energy shortfalls to 0.002% of annual demand in all years.

Table 1. Results of reliability assessment

Capacity Year	10% POE + Reserve Margin +LFAS requirement	50% POE Peak Load (MW)	Expected demand (MWh)	EUE (MWh)	EUE as % of load
2016/17	4,480	3,670	18,644,378	23.87	0.00012804%
2017/18	4,576	3,927	18,864,529	0.33	0.00000175%
2018/19	4,620	3,968	19,006,485	3.53	0.00001855%
2019/20	4,660	4,009	19,163,479	20.26	0.00010574%

Capacity Year	10% POE + Reserve Margin +LFAS requirement	50% POE Peak Load (MW)	Expected demand (MWh)	EUE (MWh)	EUE as % of load
2020/21	4,733	4,076	19,381,777	0.68	0.00000351%
2021/22	4,812	4,133	19,602,334	0.77	0.00000391%
2022/23	4,882	4,201	19,834,865	-	0.00000000%
2023/24	4,962	4,267	20,076,908	-	0.00000000%
2024/25	5,054	4,338	20,352,464	0.23	0.00000113%
2025/26	5,141	4,414	20,660,445	26.33	0.00012742%
2026/27	5,240	4,505	20,995,596	0.08	0.00000036%

It is notable in these results that the EUE is significantly higher in the 2016/17, 2019/20 and 2025/26 capacity years (but still well short of the 0.002% target). The common cause in these three years is a major plant outage occurring over the summer peak. For the 2016/17 year, the cause is the outage of the Bluewaters 2 plant (BW2_BLUEWATERS_G1) that is currently occurring. For the 2019/20 and 2025/26 years, there is a planned outage of a major facility over the summer months that is causing this result.

1.4.2 Availability Curve

The Availability Curves for years 2017/18, 2018/19 and 2019/20 are summarised in Table 2 below.

Table 2: Availability Curve, 2017/18 - 2019/20.

	2017/18	2018/19	2019/20
MR 4.5.12(b): Minimum capacity required to be provided by Availability Class 1			
Minimum capacity	3,701	3,955	3,823
MR 4.5.12(c): Capacity associated with Availability Class 2			
DSM	875	665	837

Table 7 in Section 3.2 compares the Availability Curve results obtained last year (for the 2016 LT PASA) with the LT PASA 2017 results.

The minimum capacity (Availability Class 1) in 2017/18 has decreased, and in 2018/19 has increased since last year’s LT PASA.

The maximum amount of DSM (Availability Class 2) is higher than the level reported for the 2016 LT PASA for 2017/18, and is lower for 2018/19.

These changes are the result of multiple changes in input assumptions, including:

- The available DSM facilities has been reduced from 27 facilities with capacity credits of 560.182 MW to 6 facilities with capacity credits of 106 MW. This results in the DSM optimisation model having less flexibility in allocating DSM capacity, so will result in a different optimal allocation of DSM.
- Available generation data has been updated
- Peak demand and annual energy forecasts have been updated
- Planned outage data has been updated
- The ready reserve requirement has been revised from 515 to 520 MW.

1.4.3 EDDQ

The EDDQ results are summarised in Table 3 below. This also provides the resulting DSM Reserve Capacity Price (RCP) assuming an interim Value of Lost Load (VoLL) of $33,460[2].

Table 3. EDDQ results

Capacity Year	EUE(t,0)	EUE(t,200)	CC(t)	EDDQ(t)	DSM RCP based on $33,460 VoLL (MR 4.5.14F)
2017/18	1.22	0.21	106	0.009556	$17,049.74
2018/19	9.25	2.93	106	0.059683	$18,726.99
2019/20	69.08	14.11	106	0.518606	$34,082.56
2020/21	8.84	1.90	106	0.065507	$18,921.86
2021/22	1.45	0.00	106	0.013714	$17,188.87
2022/23	0.00	0.00	106	0.000000	$16,730.00
2023/24	0.58	0.00	106	0.005510	$16,914.36
2024/25	0.77	0.00	106	0.007238	$16,972.18
2025/26	68.48	22.37	106	0.435054	$31,286.91
2026/27	2.00	0.00	106	0.018862	$17,361.12

It is notable in these results that the EUE values and resulting EDDQ and DSM RCP are significantly higher in the 2019/20 and 2025/26 capacity years. As for the reliability results, this is caused by a planned outage of a major facility over the summer months of these years.

[2] As specified in Market Rule 4.5.14F

2 - METHODOLOGY

This chapter details our methodology.

2.1 MODELLING APPROACH

We have undertaken the modelling for this project in four phases as follows:

- *Phase 1: Forecast load profile over the LT PASA Study Horizon*. This involves forecasting the Load Duration Curve (LDC) over the LT PASA study horizon, taking into account the 50% Probability of Exceedance (POE) peak forecast and the expected annual demand forecast[3] (see Section 2.2). The forecasted LDCs are a key input for Phases 2, 3 and 4.
- *Phase 2: Undertake Reliability Assessment*. This involves applying the second component of the Planning Criterion (MR 4.5.9(b)) to determine the amount of reserve capacity required to limit energy shortfalls to 0.002% of forecast annual demand for each year in the LT PASA Study Horizon. This will enable AEMO to determine the Reserve Capacity Target for each year in the LT PASA Study Horizon. We have approached this task using a combination of fundamental market modelling and Monte Carlo (probabilistic) simulations to determine the percentage of forecast demand that would not be met due to unserved energy over the LT PASA Study Horizon (see Section 2.3).
- *Phase 3: Determine Availability Curve* for the second and third years of the LT PASA Study Horizon. This phase is described in more detail in Section 2.4 and involves:
  - Determining MR 4.5.12(b) and MR 4.5.12(c) and
  - Developing the two-dimensional duration curve required under MR 4.5.10(e).
- *Phase 4: Forecast EDDQ* for ten years comprising LT PASA study horizon for the 2017/18 Reserve Capacity Cycle. This is described further in section 2.5; our approach here is similar to the Reliability Assessment (using a combination of Monte Carlo simulations and fundamental market modelling). However, DSM dispatch is modelled more comprehensively to minimise the peak while meeting availability restrictions.

[3] Provided by AEMO.

2.2 Phase 1: Forecast load profile over the LT PASA Study Horizon

One of the key inputs to Phases 2, 3 and 4 is the forecasted load profile over the LT PASA study horizon. Our approach to forecasting the load profile includes two components:

- Developing the base year load profile: First, a load duration curve is developed using historical data. This is the load profile on which all forecasted load duration curves will be based.
- Scaling the base year load profile to forecasted values: Forecasted load duration curves for each year in the LT PASA study horizon are developed by scaling up the base load profile to match the 50% POE peak and expected energy forecast for the respective year.

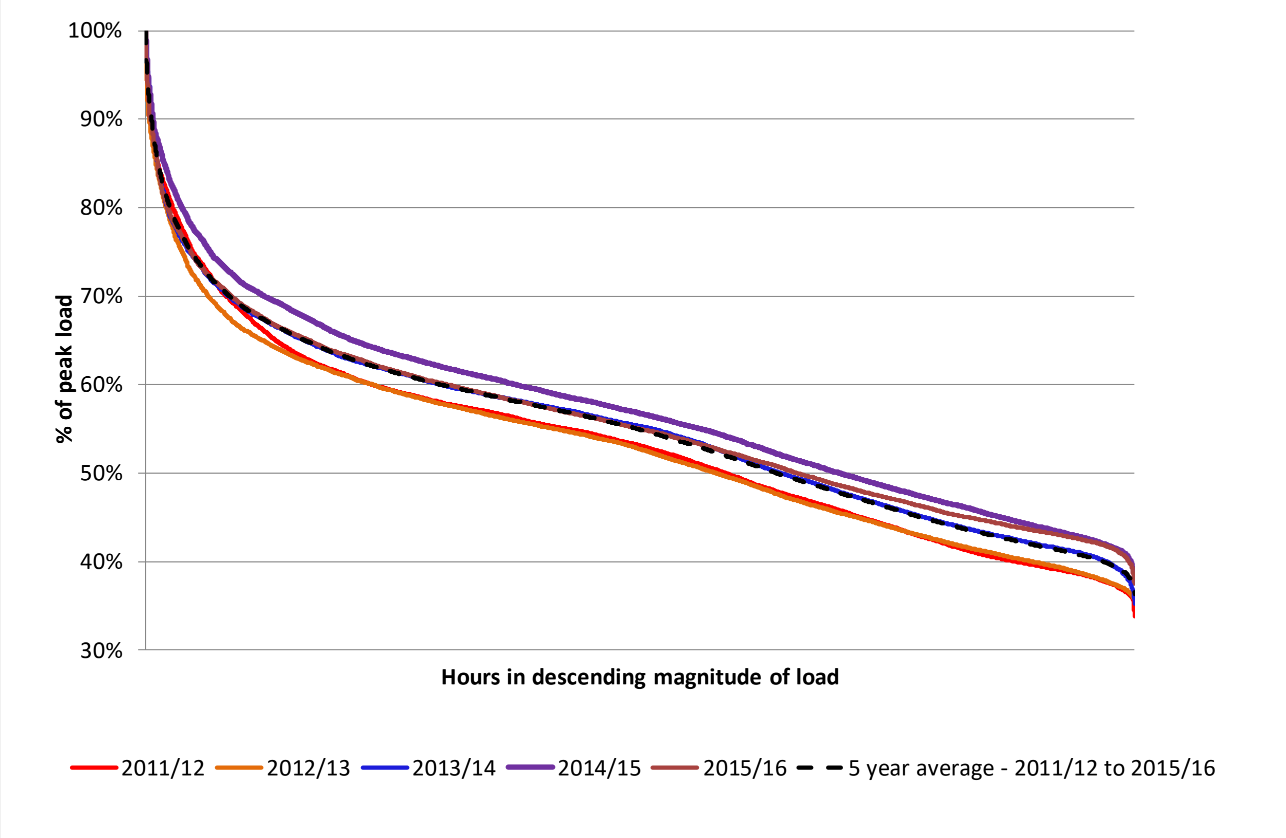
Each of the above bullets is described in more detail in the sections below.

2.2.1 Developing the base load profile

We have developed the base year load curve by averaging load duration curves over the last five capacity years (2011/12-2015/16). The advantage of this approach is that the averaging ensures that the base profile will be representative of recent history, while at the same time ensuring that more recent trends are captured with more recent data.

Figure 1 below summarises the historical LDCs alongside the average LDC (denoted by the dotted line).

Figure 1: Historical and average LDC for the Wholesale Electricity Market (2011/12-2015/16)



2.2.2 Scaling the base year load profile to forecasted values

Having developed a base year profile, we then scaled the base year profile to match the 50% POE peak forecast and expected demand in any given year.

In other words, for each year of the LT PASA forecast horizon we require a forecasted LDC such that:

- The peak of the LDC equals the 50% POE profile
- The load allocated across all hours sums to the expected demand forecast and
- The shape of the LDC is similar to the base year profile developed above.

Before describing the LDC forecasting methodology it is important to note the following:

- First, the peak and energy demand forecasts are developed separately by AEMO's Forecasting Consultant. As such, there is no explicit relationship between the peak and energy demand forecasts
- Second, the historical ratio of peak to average energy (approximately 1.8 in the last ten years) and forecasted peak to average energy ratio can be starkly different. For example, the forecasted ratios from 2012-2014 were in the region of 1.95-2.2, while in 2015 ranged from 1.7-1.9.
- Hence, the "peakiness" envisaged by the forecasts may not necessarily be consistent with recent history. This means that based on these forecasts it is not possible to derive a forecasted LDC that exactly matches the base profile (as the base profile represents a peak to average energy ratio of around 1.8).

Given the above, we have defined a function F(h) (h ∈ hours of the year), such that the forecasted LDC for a given year t ($L\widehat{D}C(h)$) can be derived by multiplying the average LDC ($\overline{LDC}(h)$) by this function. That is:

- $L\widehat{D}C(h) = F(h)\times \overline{LDC}(h)$, such that:
  - $Max\left(L\widehat{D}C(h)\right)$ = 50% POE peak forecast in year t and
  - $\sum_{h=1}^{8760} L\widehat{D}C(h)$ = Expected demand forecast in year t.

The function is defined so as to ensure that the shape of the LDC varies with differing peak/energy ratios in a way that is consistent with the historical LDCs of the last five years. Thus, we have defined F(h) as follows:

$$F(h) = \begin{cases} \dfrac{p-z}{m^2}(m-h)^2 + z \; if \; h \leq m \\ \dfrac{e-z}{(n-m)^2}(h-m)^2 + z \; if \; h > m. \end{cases}$$

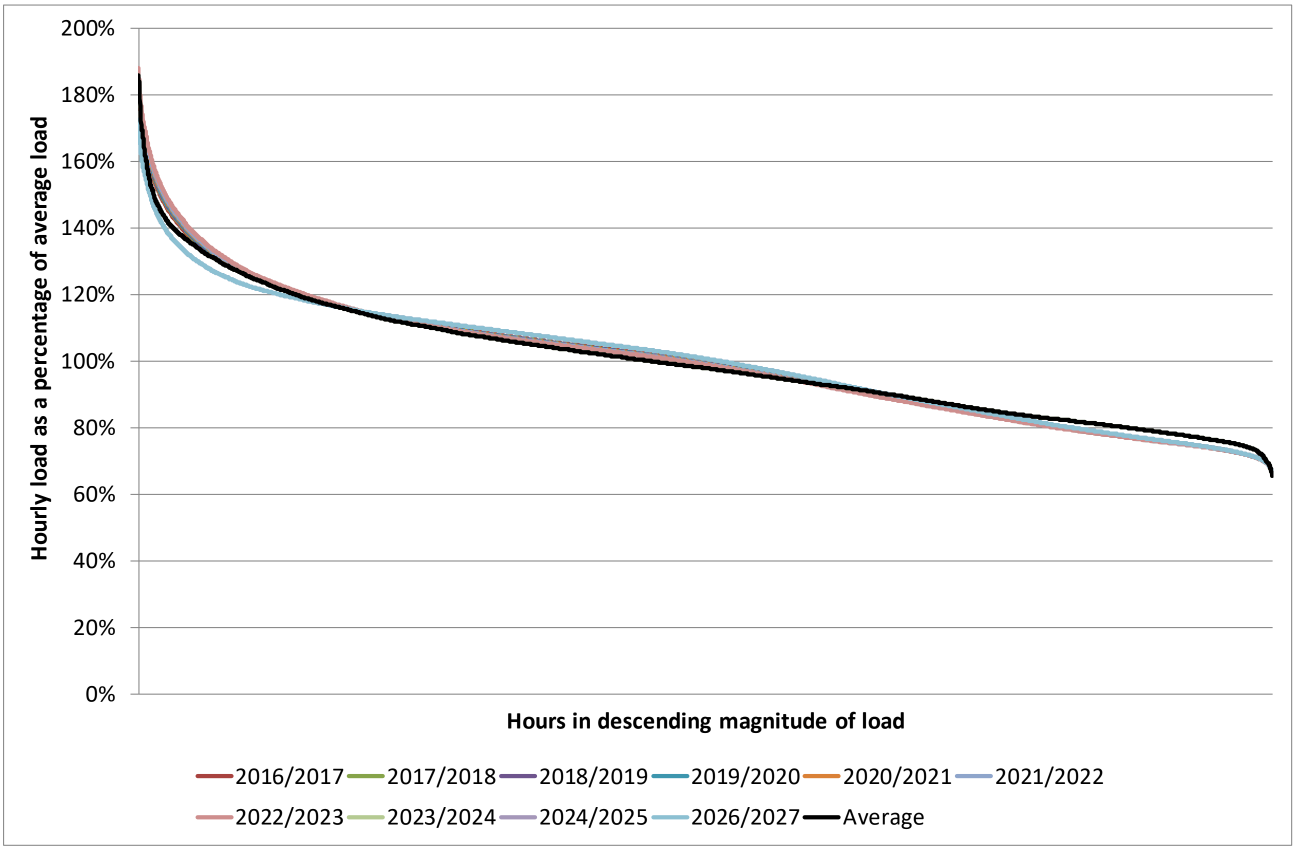
Where:

- p denotes the ratio of the 50% POE peak forecast to the five-year average peak demand
- e denotes the ratio of the expected demand forecast to the five-year average hourly demand
- m denotes the position in the LDC in which the curve flattens, as has been observed in the historical years. m is set to 3,000 hours from the observation of historical years
- n denotes the total number of hours in a year and

- z represents a curvature constant that is adjusted to achieve the expected demand forecast in the resulting LDC.

Figure 2 summarises the forecasted LDCs for the years 2016/2017 to 2026/2027 scaled up to the respective 50% POE peak forecasts and the expected demand forecasts.

Figure 2: Forecasted LDCs (2016/17-2026/27)



The scaled load profiles are key inputs into Phases 2, 3 and 4. Specifically:

- They are used to project the hourly load in a forecast year to be used for the market modelling component of:
  - Determining the expected unserved energy for the Reliability Assessment
  - Determining the minimum capacity (MR 4.5.12(b)) which is an input for the Availability Curve
  - Determining expected unserved energy for the EDDQ forecasts
- They are also used to derive the two-dimensional duration curve defined in MR 4.5.10(e), which is developed by adjusting further the scaled profiles (in Figure 2) to incorporate the

requirements of MR 4.5.10(e). This is addressed in further detail in Section 2.4 (Determine MR 4.5.10(e)).

2.3 PHASE 2: UNDERTAKE RELIABILITY ASSESSMENT

To assess the amount of reserve capacity required to limit energy shortfalls to the reliability criterion set by MR 4.5.9(b) (0.002% of annual demand) we use a combination of fundamental market modelling and probabilistic Monte Carlo simulations as follows:

1. For each year of the LT PASA study horizon, we assume reserve capacity (generating capacity and DSM) equals the forecast peak quantity plus reserve margin and Load Following Ancillary Services (LFAS) quantity determined by MR 4.5.9(a).
2. Given our forecasted load profile (based on a 50% POE peak and expected demand growth, see Section 1.1.1), assumptions on the availability of intermittent generation (see below) and randomised outages (see below) we simulate the Wholesale Electricity Market using our proprietary modelling tool (WEMSIM - see below) over a large number of iterations. Each iteration yields an estimate of unserved energy.
3. We then use the N iterations above to estimate Expected Unserved Energy (EUE) as follows:
   - $\mathrm{EUE} = \frac{1}{N}\sum_{i=1}^{N} Unserved\ Energy_i$
4. We next calculate EUE as a percentage of annual demand.
5. If the percentage in Step 4 is less than or equal to 0.002% then we stop - the Reserve Capacity Target will be set by the first component of the Planning Criterion (MR 4.5.9(a)). Note it is highly likely that the Reserve Capacity Target will be set by the first component of the Planning Criterion as it has in the past. This trend is likely to continue as the load factor appears to be reducing over time (with increased summer air conditioning) and plant availability is improving.
6. If the percentage is greater than 0.002%, then:
   - We incrementally increase the reserve capacity (over and above the forecast peak quantity determined by MR 4.5.9(a)) and
   - Repeat steps 1 to 6 until the percentage in Step 4 is less than or equal to 0.002%.

The above steps are a high-level summary of our modelling methodology for the Reliability Assessment. In the remainder of this section we provide the details around the specifics of the modelling. Specifically, the following sections outline how Steps 2 and 3 will be implemented in practice as follows:

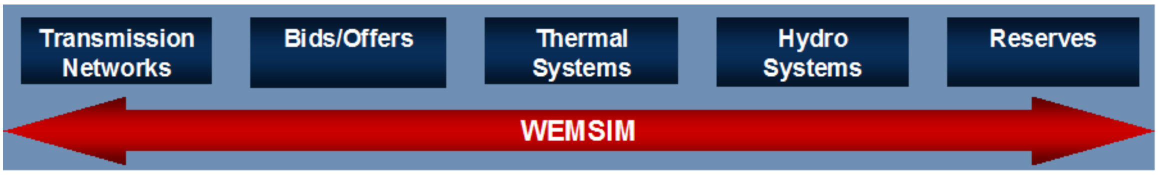
- We first describe the tool we use to undertake the fundamental modelling of the Wholesale Electricity Market
- We then describe the methodology we use to undertake Monte Carlo simulations of the Wholesale Electricity Market and
- Finally, we describe the approach we will use to treat intermittent generation and outages (which are inputs to the two components above).

2.3.1 Fundamental market modelling

The market simulation component of the Reliability Assessment is undertaken using the electricity market simulation tool (WEMSIM).

WEMSIM is an analytical dispatch planning and analysis tool that simulates the dispatch of thermal and other generation resources in a multi-regional transmission framework. WEMSIM is an optimization engine based on linear and mixed integer (MIP) programming. WEMSIM simultaneously optimises generation dispatch, reserve provision and, in MIP mode, unit commitment.

Figure 3: Overview of WEMSIM



WEMSIM requires inputs such as planting schedules, transmission information (limits, losses and outages), generator parameters (ramp rates, heat rates, outage rates, etc.) and load profiles.

In simulating the market, we run the market model a large number of times as indicated in Step 2 above (i.e. the Monte Carlo analysis), each time using a different random series for forced outages.

Our approach to undertaking the Monte Carlo analysis and treatment of outages and intermittent generation is covered in the sections below.

2.3.2 Monte Carlo simulation

To derive an estimate of Expected Unserved Energy (EUE) (as required by MR 4.5.9(b)) it is necessary to estimate a probability distribution of unserved energy for each year in the LT PASA Study Horizon. A single annual run of any fundamental market model will yield one estimate of unserved energy which is a single realisation from a probability distribution function. Hence, to estimate the EUE it is necessary to run the fundamental market model over a large number of iterations. Each one of these iterations includes probabilistically simulated forced outages and will produce one realisation of unserved energy (see Steps 2 and 3 above).

To produce a robust estimate of EUE a large number of iterations would be required. Herein lies a computational problem: running a full market model (with hourly simulation and detailed transmission representation) over a significant number of iterations is very computationally intensive, and cannot be undertaken in an efficient and timely manner.

To this end, RBP employs a methodology which combines market modelling and Monte Carlo analysis, by simulating the market in LDC blocks instead of undertaking full hourly runs.

Our approach is summarised below:

1. For each year in the LT PASA Study Horizon we decompose the forecasted LDC into five discrete blocks of varying width. For example, the forecasted LDCs could be decomposed into 5 blocks at the following breakpoints: 90%-100% of peak load, 70%-90% of peak load, 50%-70% of peak load, 25%-50% of peak load and less than 25% of peak load. As an illustrative example, see Figure 4, which represents the forecasted LDC for Western Australia for the 2016/17 Capacity Year. Here:
   - The first block is the narrowest and contains peak hours pertaining to loads between 3,337 MW and 3,760 MW. Similarly, block 5 contains off-peak hours pertaining to loads between 1,403 MW and 2,097 MW.
   - The blocks are of varying width to reflect the homogeneity of system requirements in peak, peak/shoulder, shoulder and off-peak periods and to ensure sufficient granularity in those periods where unserved energy is most likely to occur (i.e. peak and shoulder periods).

- In each block b, we randomly sample an hour N_b times (see Table 4 for illustrative sample sizes). The number of hours we sample in each block was dependent on the likelihood of encountering unserved energy in that block. In the example in Figure 4:
  - Block 1 contains the 44 hours with the highest demand.
  - We randomly sampled from this block of 43 hours 4,500 times to get a sample Sblock1 such that: $S_{block1} \in \{s_1, s_2, \ldots, s_{4500}\}$, and $S_{block1} \in \{The\ top\ 43\ hours\ with\ the\ highest\ demand\}$.
  - Unserved energy is most likely to occur in the first two selected blocks (the probability of unserved energy in the last three blocks will be negligible). For this reason, the first two blocks have the narrowest width and have the largest number of sampled hours to ensure we have greater statistical power for those hours where unserved energy is most likely.

2. We then run the market model (WEMSIM) for each sampled hour. WEMSIM dispatches plants based on load requirements (as determined by the random load pertaining to the sampled hour in the LDC), available generation (which will take into probabilistically simulated forced outages[4], availability of intermittent generation[5] by season and planned outages[6] as declared by market participants) and available DSM[7]. Each model run yields (for each sampled hour):
   - The amount generated by each plant and
   - The quantity and location of unserved energy (if any).

3. Running the market model for each one of the sampled hours in a given block will yield a sample of unserved energy estimates pertaining to that block. This will enable us to estimate the EUE for the block by averaging over this sample and multiplying by the width of the block (to get MWh). Continuing with the Figure 4 example below:

---

[4] See below for how we will model forced outages

[5] See below for details on how intermittent generation will be treated

[6] See below for details on how planned outages will be taken into account

[7] For the Reliability Assessment, DSM is modelled simplistically (as a generator of last resort with an artificially high short-run marginal cost), as the purpose here is to determine the aggregate level of Reserve Capacity required to satisfy the Planning Criterion. However, DSM will be modelled in far greater detail in the determination of the Availability Curve (MR 4.5.12(b)) and EDDQ (MR 4.5.14C), taking into account the limitations around availability (see Section 2.4).

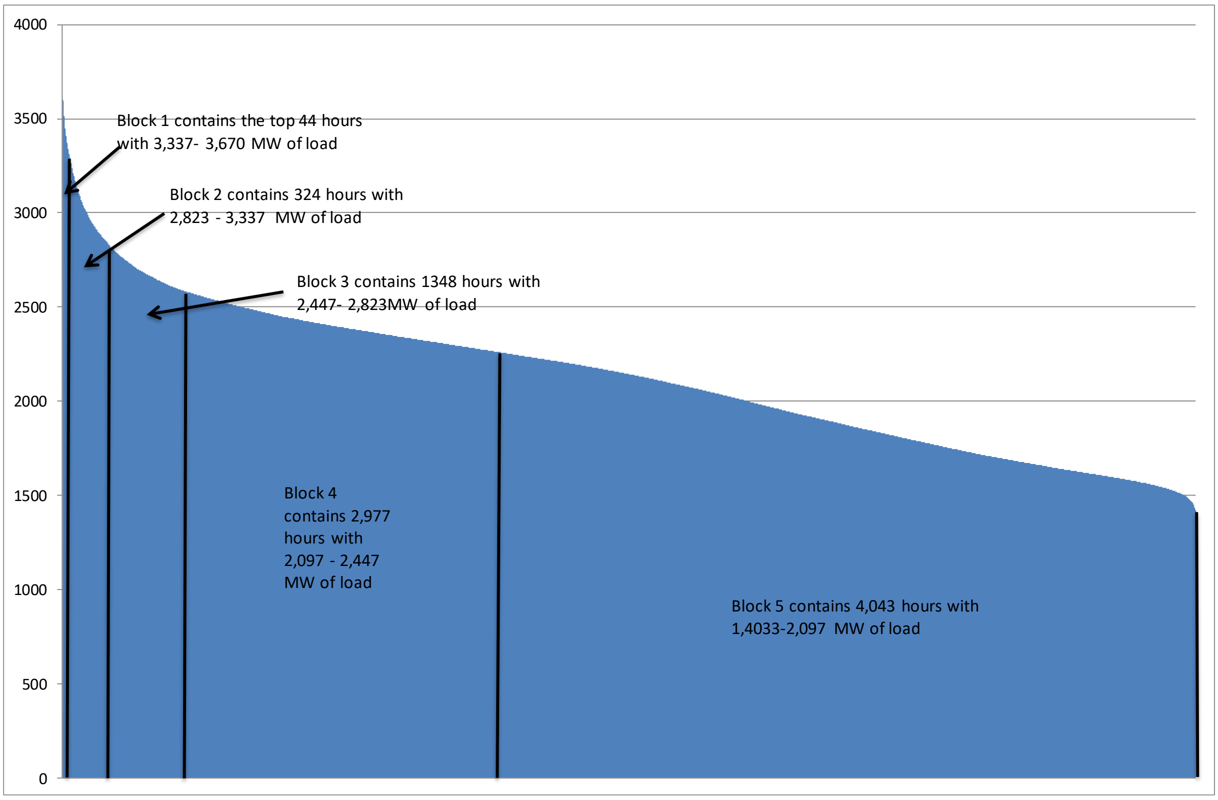
- Block 1 (with sample $S_{block1} \in \{s_1, s_2, \ldots., s_{4500}\}$,) would yield a sample of unserved energy estimates $UE_{block1} \in \{ue(s_1), ue(s_2), \ldots., ue(s_{4500})\}$.
- Block 1 has a width of 43 hours as it contains the 43 hours with the highest demand.
- Therefore, the EUE for Block 1 (in MWh) would be estimated as follows: $EUE_{block1} = \frac{1}{4500}\sum_{i=1}^{4500} ue(s_i) \times 44.$

4. Repeating Steps 1 to 3 above for each block will provide estimates for the EUE for all five blocks. We would then calculate the EUE for the entire year by summing across the blocks as follows: $EUE_{year} = \sum_{i=1}^{5} EUE_{block_i}$.
5. Steps 1 to 4 will be repeated for each year in the LT PASA Study Horizon to estimate the EUE for the relevant year.

Table 4: Illustrative sample sizes for Monte Carlo analysis

Block	Breakpoint (% of peak load forecast)	Sample size (N_b)
1	90%	4,500
2	75%	3,000
3	60%	860
4	40%	250
5	25%	126

Figure 4: Forecasted 2016/17 LDC decomposed into sampling blocks



2.3.3 Treatment of intermittent generation

Intermittent generation is modelled as follows:

- Set seasonal profiles of existing intermittent plant by reviewing historical generation (including the most recently available data).
- Set seasonal profiles of new intermittent plant based on the profiles of existing intermittent plants of similar technology and size (for example, the seasonal profile of a new wind plant would be the same as the profile of an existing wind plant of a similar size).
- Derate the intermittent plants based on the seasonal profiles above. The derated intermittent plants will be inputted into the fundamental market model in in Step 2 (Section 2.3, Monte Carlo simulation).

2.3.4 Treatment of outages

Planned outages

There are two types of planned outages that can occur in the SWIS:

- Scheduled (or long-duration) outages
- Opportunistic maintenance (or short-duration outages).

When undertaking the fundamental market modelling described in Step 2 (Section 2.3, Monte Carlo simulation) we treat outages as follows:

- *Long duration outages*:
  - Generation facilities that provided information on long duration outages will be taken out on the specified dates.
  - Generation facilities that have not provided information on long duration outages (undeclared long-duration outages) are seasonally derated based on historical planned outage information.
- *Opportunistic maintenance*. We do not model opportunistic maintenance for the following reasons:
  - Opportunistic (day-ahead and on-the-day) maintenance are subject to System Management's evaluation process, whereby an outage will not be approved (and will even be recalled) if it violates the requirements in Section 3.19 of the Market Rules; and
  - No planned outage would proceed in a period with a tight margin with a non-trivial risk of unserved energy.

Forced outages

The Monte Carlo analysis described above involves two stochastic variables:

- The load and
- The incidence of forced generation outages.

Load is randomised in the manner described in Step 1 (Section 2.3, Monte Carlo simulation).

Forced outages are randomised by:

- Determining a forced outage probability (FO_g) for each plant.
- Inputting these probabilities into the market model (in Step 2 (Section 2.3, Monte Carlo simulation)) which will then randomly assign plant outages in a sampled hour based on the specified probability.

Forced outage assumptions are developed by examining AEMO's historical outage data.

Where forced outage data is missing (e.g. for new plants) or inadequate (e.g. due to a small sample size of outages), we have made assumptions based on available forced outage data of plants of a similar size, technology and age.

2.4 Phase 3: Development of the Availability Curve

Having determined the Reserve Capacity Targets for each year, the next step involves assessing how much capacity is required for the two Availability Classes defined in the Market Rules to satisfy the targets for the second and third Capacity Years of the Long Term PASA Study Horizon as set out in Clause 4.5.12.

Additionally, clause 4.5.10(e) requires AEMO to develop a two-dimensional duration curve of the forecast minimum capacity requirements over the Capacity Year ("Availability Curve") for each of the second and third Capacity Years of the Long Term PASA Study Horizon.

In this section, we outline the approach the Availability Curve set forth in MR 4.5.12(b) and 4.5.12(c) and the two-dimensional duration curve set out in MR 4.5.10(e).

2.4.1 Determine MR 4.5.12(b)

MR 4.5.12(b) requires the determination of the minimum capacity requirement:

For the second and third Capacity Years of the Long Term PASA Study Horizon, AEMO must determine the following information:

b) the minimum capacity required to be provided by Availability Class 1 capacity if Power System Security and Power System Reliability is to be maintained. This minimum capacity is to be set at a level such that if:

- *i. all Availability Class 2 capacity (excluding Interruptible Load used to provide Spinning Reserve to the extent that it is anticipated to provide Certified Reserve Capacity), were activated during the Capacity Year so as to minimise the peak demand during that Capacity Year; and*
- *ii. the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11 were to be applied to the load scenario defined by clause 4.5.12(b)(i), then*

it would be possible to satisfy the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11, as applied in clause 4.5.12(b)(ii), using, to the extent that the capacity is anticipated to provide Certified Reserve Capacity, the anticipated installed Availability Class 1 capacity, the anticipated Interruptible Load capacity available as Spinning Reserve and, to the extent that further Availability Class 1 capacity would be required, an appropriate mix of Availability Class 1 capacity to make up that shortfall; and

RBP calculates the minimum generation requirement by repeating the modelling exercise (for the second and third years of the LT PASA Study Horizon) described in Section 2.3 with four differences:

- First, DSM is modelled in greater detail to take into account the constraints around the availability of DSM providers. In short, we will allocate DSM throughout the year using an optimisation model that dispatches DSM so as to minimise the peak and subject to scheduling and availability constraints. See below for further details on our approach to modelling DSM.
- Second, we will specify a Reserve Requirement in the market model that represents the Ancillary Services requirement of MR 3.18.11(a) (to be provided by the AEMO). We will assume that only generation facilities that nominate themselves as reserve providers will provide reserve. This ensures that there is always a capacity margin equal to the Ancillary Services Requirement in any given hour.
- Third, forced outages are taken out of the model; the only stochastic component of the simulation is load. The reason for the removal of forced outages is that the specification of a reserve requirement on top of forced outages effectively over-estimates the capacity margin. The purpose of the Ancillary Services Requirement is to cover unforeseen events such as forced outages. As such, if there were a forced outage in a given period, the operating reserve would be used to generate to prevent unserved energy. Hence, including forced outages and maintaining the Ancillary Services Requirement could lead to expected unserved energy exceeding 0.002% of annual demand.
- Finally, for each year of the relevant Reserve Capacity Cycle, we iterate the model to reallocate the amount of DSM and generating capacity (keeping the total capacity capped at the Reserve Capacity Target level) until the EUE requirement in MR 4.5.9(b) is violated.

The level of generation capacity at which the EUE equals 0.002% of expected demand sets the minimum capacity.

DSM Modelling Methodology

DSM in the Wholesale Electricity Market is subject to availability constraints. RBP forecasts hourly DSM dispatch by allocating available DSM throughout the year based on an optimisation model that takes into account the constraints above. Our approach is detailed further below:

1. Forecast sequential hourly load for the year using the methodology described in Section 2.2.
2. Use a spreadsheet based optimisation model which, given the forecasted hourly load, dispatches DSM facilities (excluding Interruptible Load as required under MR 4.5.12(b)) for each year to minimise the forecasted peak demand subject to the DSM's availability and dispatch constraints. The model performs the dispatch using a heuristic allocation method.
   - It should be noted that the nature of the problem of optimally allocating DSM is such that it would be computationally infeasible to guarantee that the result is the absolute optimum dispatch of DSM. The heuristic used will produce a dispatch that is close to optimal. We consider this to be acceptable, as the real-world dispatch of DSM is unlikely to be optimal either.
3. Adjust the LDC used in the market modelling by subtracting the forecasted DSM dispatch in the relevant hours (from Step 1 above). This adjusted LDC represents the "effective demand" and be used in the derivation of the minimum capacity contemplated by MR 4.5.12(b).

2.4.2 Determine MR 4.5.12(c)

MR 4.5.12(c) requires determining the capacity associated with Availability Class 2:

For the second and third Capacity Years of the Long Term PASA Study Horizon, AEMO must determine the following information:

c) the capacity associated with Availability Class 2, where this is equal to the Reserve Capacity Target for the Capacity Year less the minimum capacity required to be provided by Availability Class 1 capacity under clause 4.5.12(b).

This is a straightforward calculation and is computed by:

- Subtracting the minimum generation capacity, calculated above (see Section 2.4, Determine MR 4.5.12) from
- The Reserve Capacity Targets (RCT) for the relevant Reserve Capacity Cycle (determined in Section 2.3).

2.4.3 Determine MR 4.5.10(e)

Clause 4.5.10(e) requires AEMO to:

develop a two-dimensional duration curve of the forecast minimum capacity requirements over the Capacity Year ("Availability Curve") for each of the second and third Capacity Years of the Long Term PASA Study Horizon. The forecast minimum capacity requirement for each Trading Interval in the Capacity Year must be determined as the sum of:

i. *the forecast demand (including transmission losses and allowing for Intermittent Loads) for that Trading Interval under the scenario described in clause 4.5.10(a)(iv); and*

ii. *the difference between the Reserve Capacity Target for the Capacity Year and the maximum of the quantities determined under clause 4.5.10(e)(i) for the Trading Intervals in the Capacity Year.*

Our interpretation of MR 4.5.10(e)(i) and the load scenario contemplated in MR 4.5.10(a)(iv) in deriving the LDC above was undertaken in consultation with the IMO and AEMO in previous years. Particularly, the approach above is predicated on the assumption that the difference between a 10% POE peak year and a 50% POE peak year (assuming expected demand growth) would only manifest itself in the first 24 hours (i.e. the peakiest part of the LDC). Hence, we model the forecast capacity requirement as a combination of the 10% POE peak LDC and 50% POE peak LDC (where these LDCs are derived in the manner described in Section 2.2).

Our approach to determining this quantity is summarised below.

1. Forecast the LDC for a given year as specified in MR 4.5.10(e)(i). To do this:
    a. We estimate the forecast load in the first 24 hours assuming a 10% POE peak forecast and expected demand growth (i.e. the load scenario contemplated in MR 4.5.10(a)(iv)). This estimation will be undertaken using the scaling methodology described in Section 2.2.
    b. We then estimate the forecast load for the remaining hours (hours 25-8,760) hours assuming a 50% POE peak forecast and expected demand growth.
    c. We then use a smoothing function to smooth out the LDC in the first 72 hours.
2. Add the Reserve Margin and LFAS component of the MR 4.5.9(a) calculation (as provided by the AEMO) on top of the above LDC as required by MR 4.5.10(e)(ii).

2.5 PHASE 4: FORECAST EXPECTED DSM DISPATCH QUANTITY (EDDQ)

We have forecasted the EDDQ for the ten years comprising the LT PASA study horizon for the 2017/17 Reserve Capacity cycle using a combination of the approaches used to undertake the Reliability Assessment (Section 2.3) and to determine the minimum generation component of the Availability Curve (Section 2.4.1).

Our approach is summarised in further detail below:

1. Forecast Expected Unserved Energy when DSM is dispatched for zero hours ($EUE_{t,0}$). This involves repeating the Reliability Assessment as described in Section 2.3 but setting the available capacity of all DSM facilities to zero MWs. In other words, the Reliability Assessment is conducted with total reserve capacity in year t equal to
   - forecast peak quantity plus reserve margin and Load Following Ancillary Services (LFAS) quantity determined by MR 4.5.9(a) for year t minus
   - Total level of capacity credits expected to be assigned to DSM facilities in year t.

   Hence, only generation capacity is available to meet demand as described in MR 4.5.14C(a).
2. Forecast Expected Unserved Energy when DSM is dispatched for 200 hours ($EUE_{t,200}$). This involves repeating the Step 1 above but with the following difference:
   - As above, set total reserve capacity in year to the forecast peak less expected DSM Capacity Credits.
   - Adjust the forecasted LDC for year t (developed in Section 2.2) to take into account DSM dispatch for exactly 200 hours. The forecast LDC is adjusted using the DSM dispatch model described in Section 2.4.1 (DSM Modelling Methodology) with an additional constraint requiring that all DSM facilities are dispatched for exactly 200 hours. Hence, DSM is dispatched to minimise the peak (in accordance with MR 4.5.12(b)) while respecting availability constraints and the 200-hour dispatch requirement. The optimised DSM dispatch is then deducted off the forecasted LDC, and it is this adjusted LDC that becomes an input into the market model.
   - Here, generation capacity plus exactly 200 hours of DSM dispatch is available to meet demand as described in MR 4.5.14C(b).
3. Calculate EDDQ in year t as follows:

$$EDDQ_t = \frac{EUE_{t,0} - EUE_{t,200}}{Expected\ DSM\ Capacity\ Credits_t}.$$

3 - RESULTS

Our results are summarised in this chapter.

3.1 RELIABILITY ASSESSMENT

The Reliability Assessment indicated that for all years of the LT PASA forecast horizon (2016/17 to 2026/27) the Reserve Capacity Targets will be set by the forecast peak quantity determined by **MR 4.5.9(a)**.

The EUE as a percentage of annual demand when total capacity is capped at the forecast peak component given by **MR 4.5.9(a)** (first column) is summarised in Table 1. Here we see that the peak forecast component is sufficient to limit expected energy shortfalls to 0.002% of annual demand in all years.

Table 5. Results of reliability assessment

Capacity Year	10% POE + Reserve Margin +LFAS requirement	50% POE Peak Load (MW)	Expected demand (MWh)	EUE (MWh)	EUE as % of load
2016/17	4,480	3,670	18,644,378	23.87	0.00012804%
2017/18	4,576	3,927	18,864,529	0.33	0.00000175%
2018/19	4,620	3,968	19,006,485	3.53	0.00001855%
2019/20	4,660	4,009	19,163,479	20.26	0.00010574%
2020/21	4,733	4,076	19,381,777	0.68	0.00000351%
2021/22	4,812	4,133	19,602,334	0.77	0.00000391%
2022/23	4,882	4,201	19,834,865	-	0.00000000%
2023/24	4,962	4,267	20,076,908	-	0.00000000%
2024/25	5,054	4,338	20,352,464	0.23	0.00000113%
2025/26	5,141	4,414	20,660,445	26.33	0.00012742%
2026/27	5,240	4,505	20,995,596	0.08	0.00000036%

It is notable in these results that the EUE is significantly higher in the 2016/17, 2019/20 and 2025/26 capacity years (but still well short of the 0.002% target). The common cause in these three years is a major plant outage occurring over the summer peak. For the 2016/17 year, the cause is the outage of the Bluewaters 2 plant (BW2_BLUEWATERS_G1) that is currently occurring. For the 2019/20 and 2025/26 years, there is a planned outage of a major facility over the summer months that is causing this result.

3.2 Availability Curve

The Availability Curves for years 2017/18, 2018/19 and 2019/20 are summarised in Table 6 below. The load duration curves used to estimate **MR 4.5.10(e)** are illustrated in Figure 5, Figure 6 and Figure 7.

Table 6: Availability Curve, 2017/18 - 2019/20.

	2017/18	2018/19	2019/20
MR 4.5.12(b): Minimum capacity required to be provided by Availability Class 1			
Minimum capacity	3,701	3,955	3,823
MR 4.5.12(c): Capacity associated with Availability Class 2			
DSM	875	665	837

Figure 5: Forecast capacity required, 2017/18

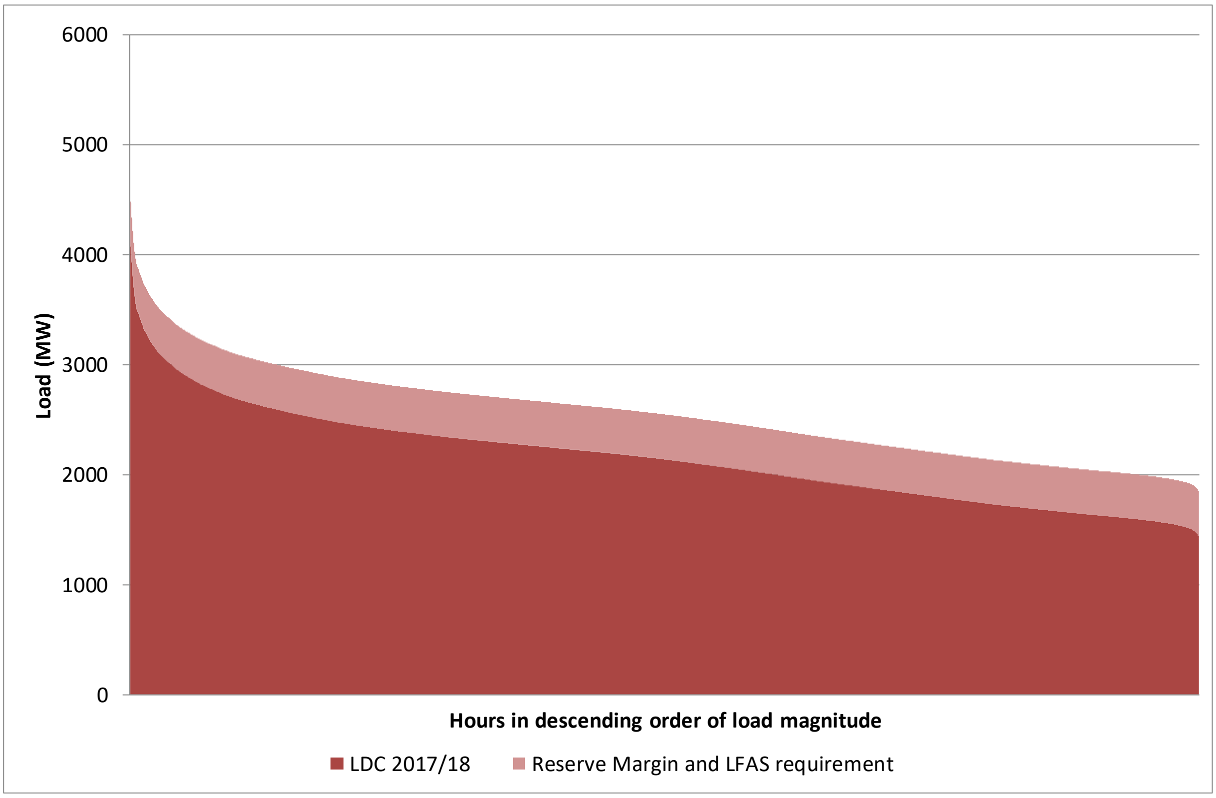


Figure 6: Forecast capacity required, 2018/19

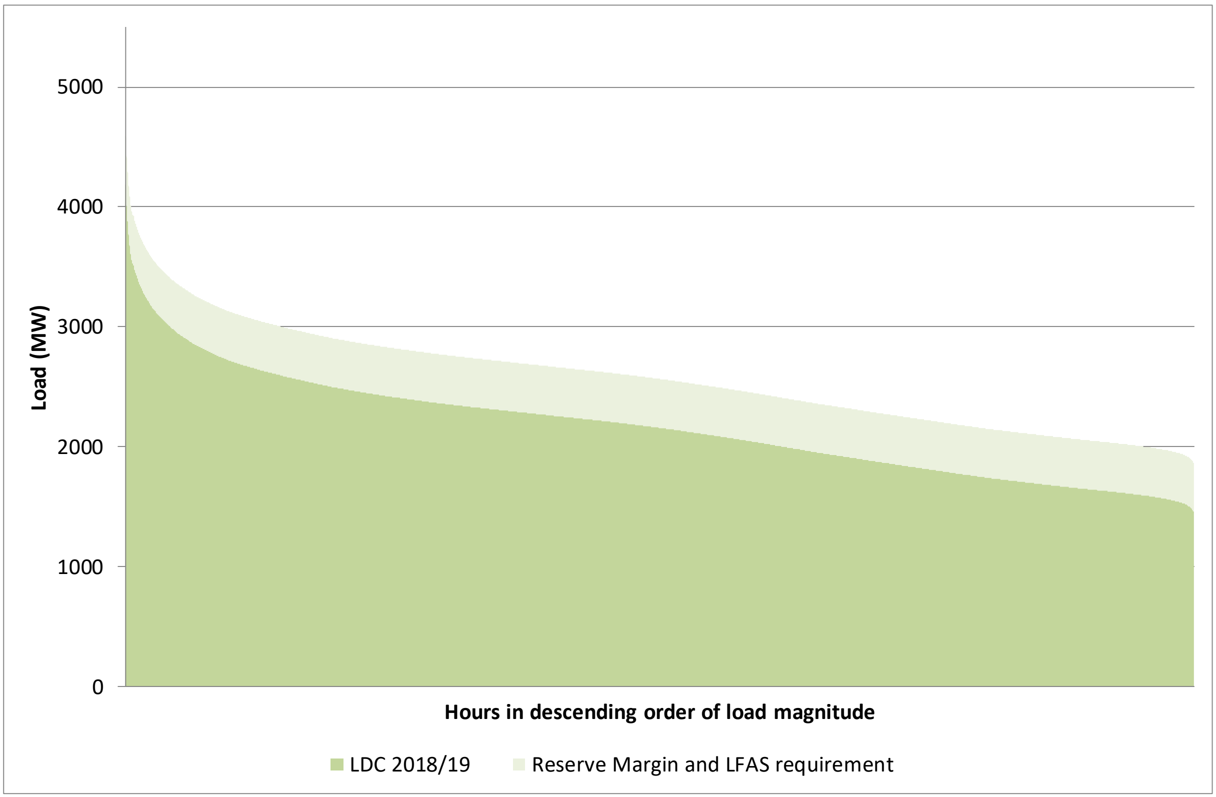


Figure 7: Forecast capacity required, 2019/20

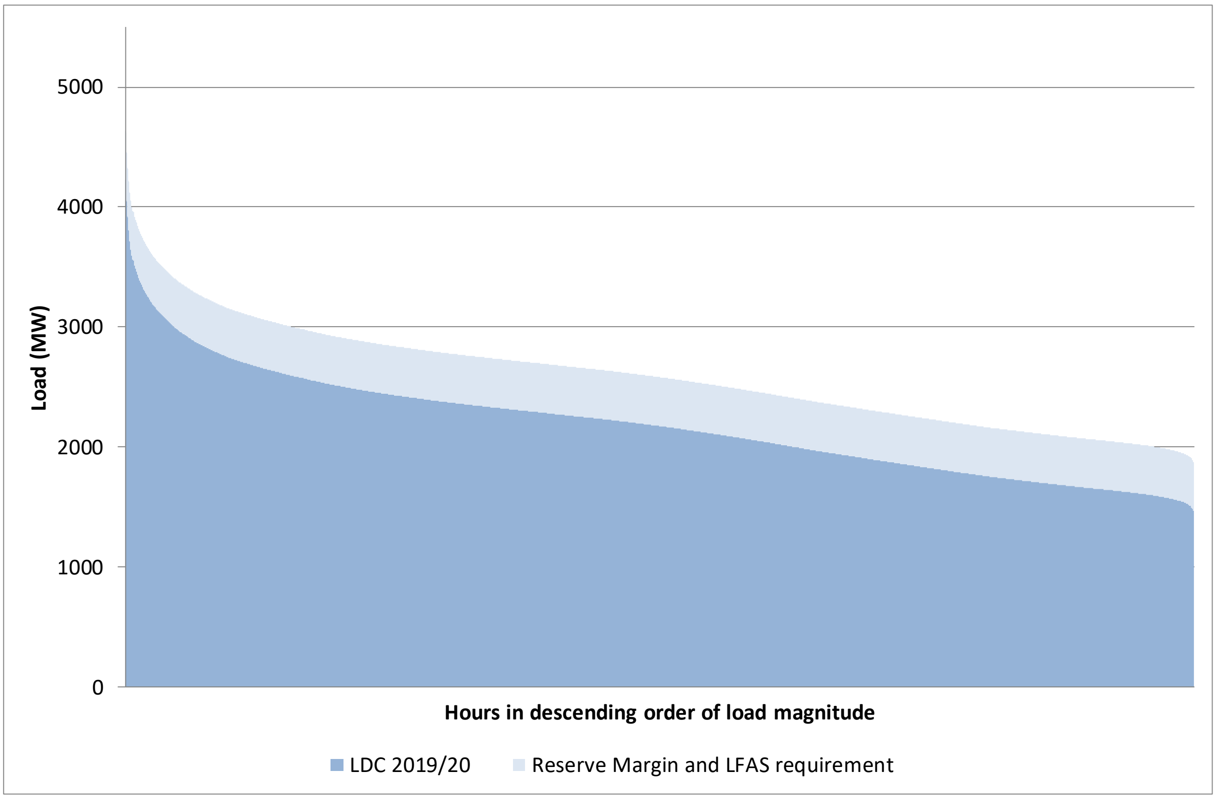


Table 7 compares the Availability Curve derived for the 2016 LT PASA. The 2016 LT PASA values are provided in parentheses.

Table 7: Comparing LT PASA 2017 Availability Curve to LT PASA 2016 Availability Curve (2016 results in parentheses)

	2017/18	2018/19	2019/20
MR 4.5.12(b): Minimum capacity required to be provided by Availability Class 1			
Minimum capacity	3701 (3792)	3955 (3861)	3823
Reserve Capacity Target			
Reserve Capacity Target	4576 (4552)	4620 (4616)	4660
MR 4.5.12(c): Capacity associated with Availability Class 2			
DSM	875 (760)	665 (755)	837

The minimum capacity (Availability Class 1) in 2017/18 has decreased, and in 2018/19 has increased since last year's LT PASA.

The maximum amount of DSM (Availability Class 2) is higher than the level reported for the 2016 LT PASA for 2017/18, and is lower for 2018/19.

These changes are the result of multiple changes in input assumptions, including:

- The available DSM facilities has been reduced from 27 facilities with capacity credits of 560.182 MW to 6 facilities with capacity credits of 106 MW. This results in the DSM optimisation model having less flexibility in allocating DSM capacity, so will result in a different optimal allocation of DSM.
- Available generation data has been updated
- Peak demand and annual energy forecasts have been updated
- Planned outage data has been updated
- The ready reserve requirement has been revised from 515 to 520 MW.

3.3 Forecast EDDQ

The EDDQ results are summarised in Table 3 below. This also provides the resulting DSM Reserve Capacity Price (RCP) assuming an interim Value of Lost Load (VoLL) of $33,460[8].

[8] As specified in Market Rule 4.5.14F

Table 8. EDDQ results

Capacity Year	EUE(t,0)	EUE(t,200)	CC(t)	EDDQ(t)	DSM RCP based on $33,460 VoLL (MR 4.5.14F)
2017/18	1.22	0.21	106	0.009556	$17,049.74
2018/19	9.25	2.93	106	0.059683	$18,726.99
2019/20	69.08	14.11	106	0.518606	$34,082.56
2020/21	8.84	1.90	106	0.065507	$18,921.86
2021/22	1.45	0.00	106	0.013714	$17,188.87
2022/23	0.00	0.00	106	0.000000	$16,730.00
2023/24	0.58	0.00	106	0.005510	$16,914.36
2024/25	0.77	0.00	106	0.007238	$16,972.18
2025/26	68.48	22.37	106	0.435054	$31,286.91
2026/27	2.00	0.00	106	0.018862	$17,361.12

It is notable in these results that the EUE values and resulting EDDQ and DSM RCP are significantly higher in the 2019/20 and 2025/26 capacity years. As for the reliability results, this is caused by a planned outage of a major facility over the summer months of these years.

4 - ASSUMPTIONS

The assumptions underlying our market modelling are detailed in this section.

4.1 FACILITY ASSUMPTION

4.1.1 Capacity credit assumptions

The amount of capacity credits assumed by facility is summarised in this section. The capacity credits (provided by the AEMO and Market Participants) for each facility were pro-rated so that the total number of capacity credits in a given year summed to the forecast peak component given by **MR 4.5.9(a)** for that year as follows:

$$CC_{i_{adjusted}} = CC_i \times \frac{10\%\ POE\ peak + Reserve\ Margin + LFAS}{\sum_{j \in all\ facilities} CC_j}$$

Capacity credits assumptions have been made based on the AEMO's request for information under market rule 4.5.3.

4.1.2 Seasonal profiles for intermittent generation

Seasonal production profiles were analysed for existing intermittent facilities.

Seasonal profiles for existing intermittent facilities are based on historical seasonal averages over the last six years.

Seasonal profiles for new intermittent facilities are based on capacity factors of existing intermittent generators of similar technology and size.

Seasonal profile assumptions have been made based on the AEMO's request for information under market rule 4.5.3.

4.1.3 Forced outage assumptions

The forced outage rate assumptions for generating facilities were set by:

- Examining historical forced and consequential outage rates for existing generation facilities since market start[9]
- Analysing forced outage rates for generation facilities of similar technologies using other data sources including:
  - The North American Reliability Council's (NERC) Generation Availability Database
  - Forced outage rate assumptions used for planning purposes by the Australian Energy Market Operator (AEMO)
  - Forced outage rate assumptions used by the Electricity Authority in New Zealand to update their Electricity Generation Database.

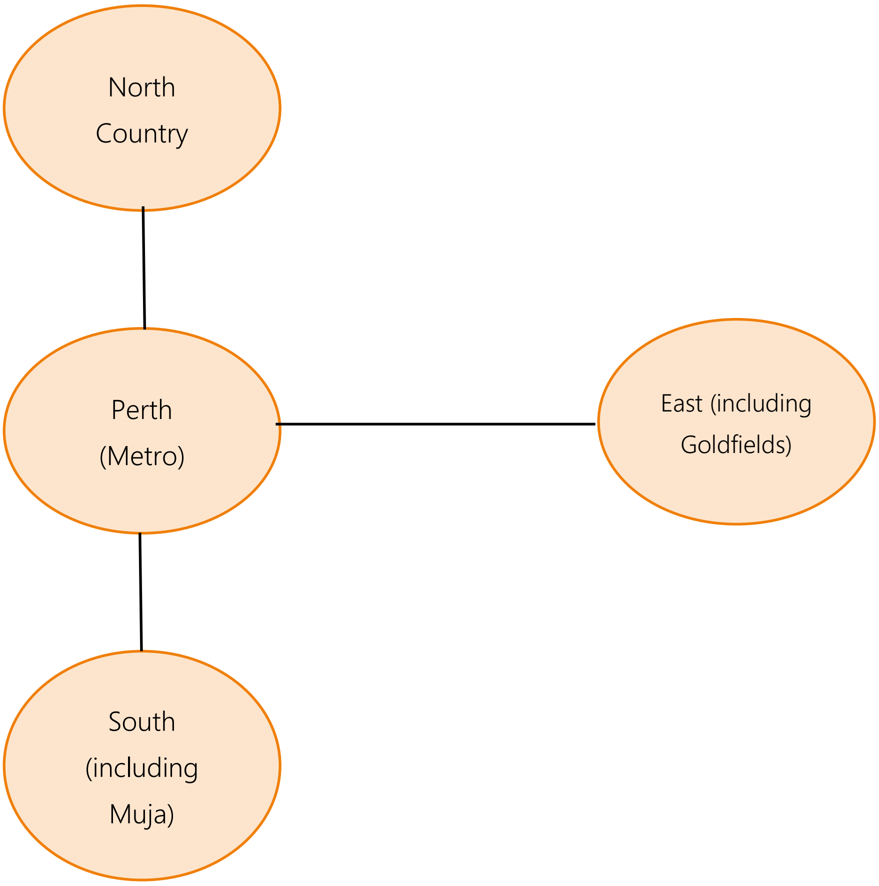
[9] Historical forced outage rates were weighted by the amount of generation on outage (to take into account partial outages).

4.2 TRANSMISSION ASSUMPTIONS

4.2.1 Network topography

Four regions (or nodes) were represented in the market model as illustrated in Figure 8 below.

Figure 8 Network topography



4.2.2 Network constraints

No line constraints were modelled on instruction from the AEMO as Western Power has implemented various measures to manage localised constraints, outside of the Reserve Capacity Mechanism, such as:

- Offering curtailable access to new loads that wish to connect to the grid in "constrained" regions. For example, any new load wishing to connect in the Goldfields will be provided an access contract that mandates that the load be curtailed under certain conditions and
- Network Control Services (NCS). Western Power is currently seeking to procure NCS capacity as an alternative to, or to allow deferral of, network investment.

4.2.3 Losses

No losses were modelled for transmission lines as peak and total demand forecasts were calculated on a "generation sent-out basis". The inclusion of losses in the demand forecasts were such that they were difficult to extricate from the final forecasts. As such line losses were not included in the model.

4.2.4 Nodal load participation factors

Load participation factors for the four regions in Figure 8 were calculated using Western Power's estimates of forecasted peak load by region.

4.3 DEMAND ASSUMPTIONS

Demand forecasts used to develop the forecast LDCs are summarised in Table 9.

Table 9: Summary of peak and total demand forecasts (expected growth), 2016/17 - 2027/28

Capacity Year	50% POE peak forecast, MW	10% POE peak forecast, MW	Annual demand, TWh
2016/17	3,670	4,073	18,644
2017/18	3,927	4,169	18,865
2018/19	3,968	4,213	19,006
2019/20	4,009	4,253	19,163
2020/21	4,076	4,326	19,382
2021/22	4,133	4,401	19,602
2022/23	4,201	4,466	19,835
2023/24	4,267	4,541	20,077
2024/25	4,338	4,626	20,352
2025/26	4,414	4,707	20,660
2026/27	4,505	4,799	20,996
2027/28	4,591	4,904	21,330

4.4 Reserve Capacity Target

The Reserve Capacity Targets used in the reliability assessment and availability curve development are summarised in Table 10.

Table 10: Reserve Capacity Targets 2016/17 - 2027/28

	Maximum Demand	Intermittent Loads	Reserve Margin	Load Following	Reserve Capacity Target
2016/17	4,073	4	331	72	4,480
2017/18	4,169	4	331	72	4,576
2018/19	4,213	4	331	72	4,620
2019/20	4,253	4	331	72	4,660
2020/21	4,326	4	331	72	4,733
2021/22	4,401	4	335	72	4,812
2022/23	4,466	4	340	72	4,882
2023/24	4,541	4	345	72	4,962
2024/25	4,626	4	352	72	5,054
2025/26	4,707	4	358	72	5,141
2026/27	4,799	4	365	72	5,240
2027/28	4,904	4	373	72	5,353

4.5 Demand side programme assumptions

The DSM programme information is used to optimise load curtailment in the Availability Curve calculations (see Section 2.4.1). Assumptions have been made based on the AEMO's request for information under market rule 4.5.3.