ROBINSON BOWMAKER PAUL

AUSTRALIAN ENERGY MARKET OPERATOR

Final Report: 2020 Assessment of System Reliability, Development of Availability Curve and DSM Dispatch Quantity Forecasts for the South West Interconnected System

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EXECUTIVE SUMMARY

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

- Undertake the reliability assessment and development of the Availability Curve and Availability Classes for the South West interconnected system (SWIS)
- Forecast the Expected DSM Dispatch Quantity (EDDQ) in accordance with clause 4.5.14A of the Wholesale Electricity Market Rules (WEM Rule 4.5.14A) and the Market Procedure: Determination of the Expected DSM Dispatch Quantity and the DSM Activation Price.

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, AEMO undertakes a Long Term Projected Assessment of System Adequacy (LT PASA). The results of the LT PASA analysis feed into AEMO's Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO). The LT PASA forecasts:

- The Reserve Capacity Target (RCT) for each year in the LT PASA study (WEM Rule 4.5.10(b)) and the Reserve Capacity Requirement (WEM Rule 4.6.1). The RCT is set to meet the Planning Criterion which is defined in WEM Rule 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 (WEM Rule 4.5.9(a)) and
  - A reliability component to ensure expected energy shortfalls are limited to 0.002% of annual energy consumption (WEM Rule 4.5.9(b)).
- Generation capacity and Demand Side Management (DSM) requirements in the form of the Availability Classes, which is defined by WEM Rule 4.5.12.
- The Availability Curve to determine the minimum capacity requirement for each Trading Interval in the Capacity Year, which is defined by WEM Rule 4.5.10(e).

Additionally, WEM Rule 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 modelling exercise is to:

- Undertake a reliability assessment to ensure the RCT is compliant with WEM Rule 4.5.9(b)
- Determine the minimum capacity required to be provided by Availability Class 1[1] and the capacity associated with Availability Class 2[2], defined by WEM Rule 4.5.12.
- Develop the Availability Curve defined by WEM Rule 4.5.10(e).
- Forecast the EDDQ defined by WEM Rule 4.5.14A.

Scope of Modelling

Our modelling covers:

- The reliability assessment for the 2020 LT PASA Study Horizon covering Capacity Years 2020-21 to 2029-30
- The Availability Curve for the second and third year of the 2020 Reserve Capacity Cycle (2021-22 and 2022-23).
- The Availability Classes for the second and third year of the 2020 Reserve Capacity Cycle (2021-22 and 2022-23).
- The EDDQ covering Capacity Years 2020-21 to 2029-30.

Methodology[3]

Our modelling has five phases:

- Phase 1: Hourly Load Forecasting. Forecasting the hourly underlying load trace over the LT PASA study horizon, taking into account the annual 50% Probability of Exceedance (POE) summer peak forecast, expected annual energy consumption forecasts and hourly DER contribution.

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[1] The minimum generation capacity required if all DSM were activated to meet the reliability component of the Planning Criterion (WEM Rule 4.5.9(b)) and ensure the outage scheduling requirements set by WEM Rule 3.18.11 are met.

[2] Capacity not expected to be available for dispatch for all trading intervals (i.e. DSM).

[3] The peak demand and energy consumption forecasts applied for all phases of the modelling are developed under the expected demand growth scenario.

- **Phase 2: Reliability Assessment.** Simulating expected unserved energy (EUE) over the LT PASA Study horizon to apply the second component of the Planning Criterion (WEM Rule 4.5.9(b)) and determine the amount of Reserve Capacity required to limit expected energy shortfalls to 0.002% of forecast annual energy consumption. This will enable AEMO to determine the RCT for each year in the LT PASA Study Horizon.
- **Phase 3: Availability Class Requirements.** Determining the Availability Class requirements contemplated by WEM Rules 4.5.12(b)[4] and 4.5.12(c)[5] and
- **Phase 4: Availability Curves**. Developing the two-dimensional duration curves required under WEM Rule 4.5.10(e)
- **Phase 5: EDDQ**. Determining the EDDQ for each Capacity Year of the LT PASA Study Horizon.

Phase 1: Hourly Load Forecasting

This year, we have updated our load forecasting methodology to capture ongoing and expected future changes in load shapes and the timing of peak periods (load chronology) in the SWIS, caused by increasing distributed energy resources (DER) penetration, including behind-the-meter (BTM) PV and battery storage uptake[6]. To achieve this, we have developed forecasts of the operational load shape and chronology for each individual Capacity Year. This is done by creating hourly underlying demand forecasts[7], and subtracting hourly forecasts of BTM PV and battery storage contribution to create preliminary hourly operational forecasts, which is converted into a load profile. This load profile is then scaled to ensure alignment with the forecast operational 50% POE summer peak and annual sent-out energy consumption forecasts provided by AEMO.

Our new approach to forecasting the load profile has five steps:

i. Create the underlying load profile: The underlying load shape has been developed using historical sent out generation data[8] (adding historical BTM PV generation to get underlying load) to derive an average load shape; this has been applied to the 2018-19 load chronology (i.e. the hour with the largest underlying load in 2018-19 is the hour with

[4] The capacity associated with Availability Class 1.

[5] The capacity associated with Availability Class 2.

[6] This does not include the impact of electric vehicles consumption.

[7] Based on historical data and AEMO's underlying peak/energy consumption forecasts.

[8] Based on the Total Sent Out Generation data provided by AEMO.

the largest underlying load in our forecasts and likewise for the 2nd, 3rd - 8760th hour) to create the underlying reference load profile.

ii. Scale the underlying load profile to forecasted values: Hourly underlying load forecasts for each year in the LT PASA Study Horizon have been developed by scaling up the underlying reference load profile to match the underlying 50% POE peak and expected energy forecasts for the respective Capacity Year.

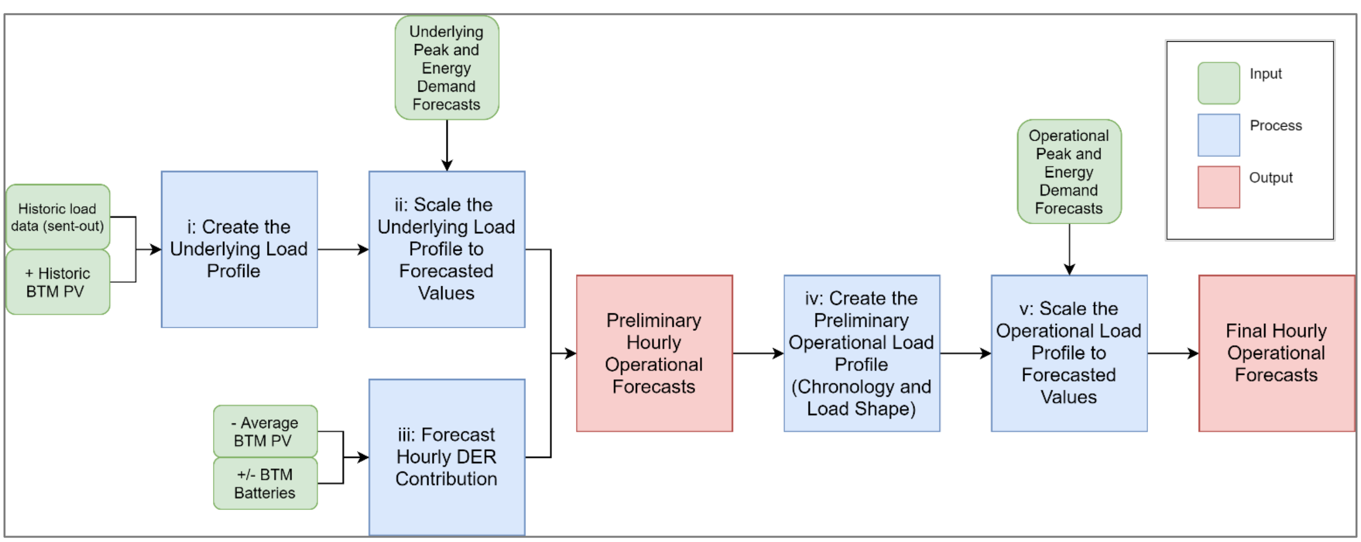
iii. Forecast hourly DER contribution: Using DER data provided by AEMO, we forecast hourly BTM PV generation (averaged across five 'outage sequences' reflecting stochastic weather and cloud cover), and battery charge/discharge, for each Capacity Year.

iv. Create the preliminary operational load profile (chronology and load shape): The hourly underlying load forecasts and hourly DER contribution forecasts have been combined and adjusted for losses to create hourly operational load forecasts. These are processed into an operational load profile for each Capacity Year.

v. Scale the operational load to forecasted operational demand and consumption values: To ensure that our hourly operational load forecasts align with the operational peak demand and annual energy consumption forecasts provided by AEMO we have scaled the operational load profile to forecasted values, producing the final hourly operational load forecasts to be used in the modelling.

Figure 1 provides an overview of the load forecasting process. Boxes in green reference inputs, boxes in blue reference each step in the process (described in more detail in Sections 2.2.1 - 2.2.5), while red boxes refer to outputs.

Figure 1: Overview of load forecasting process



Phase 2: Reliability Assessment

We have used our bespoke model, CAPSIM[9] to conduct the reliability assessment. CAPSIM simulates the capacity gap (a simple arithmetic calculation subtracting load from available generation capacity) for every hour of every year, sequentially, given a specific generation mix, load forecast, planned outage schedule and random forced outages. Generator Interim Access (GIA)[10] constraints have been modelled to ensure available GIA generation is constrained down when a constraint is binding.

The purpose of this phase is to assess the amount of Reserve Capacity required to limit expected energy shortfalls to the Planning Criterion set by WEM Rule 4.5.9(b) (0.002% of annual energy). In doing this we follow the subsequent steps:

1. For each year of the Long Term PASA Study Horizon, we assume Reserve Capacity (generating capacity and DSM) equals the forecast peak quantity plus the reserve margin, Intermittent Load (IL) allowance and Load Following Ancillary Services (LFAS) quantity determined by WEM Rule 4.5.9(a).
2. For the hourly load forecast (see Section 2.2), based on assumptions of the availability of intermittent generation (see Section 2.3.3), planned outages (see Section 2.3.4) and randomised forced outages (see Section 2.3.5), we simulate the capacity gap (the difference between available capacity and load) in CAPSIM. Each iteration yields an estimate of unserved energy.
3. We then use the N iterations above to estimate EUE as follows:

$$\mathrm{EUE}_{\mathrm{loadforecast}_t} = \frac{1}{N}\sum_{i=1}^{N} Unserved\ Energy_{i,t}$$

$\mathrm{EUE}_{\mathrm{loadforecast}_t}$ denotes the estimate of EUE simulated by CAPSIM, hourly load forecast for year t.

4. We then calculate this average EUE as a percentage of annual energy consumption.
5. If the percentage in Step 4 is less than or equal to 0.002% then we stop; the RCT will be set by the first component of the Planning Criterion (WEM Rule 4.5.9(a)).
6. If the percentage is greater than 0.002%, then:

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[9] CAPSIM is developed in Python, utilising the open-source packages Pandas and NumPy for tabular processing and vectorised operations.

[10] The GIA arrangement was developed to facilitate new generation connections on a constrained basis. It is not scalable and was intended as an interim solution. Generators connected under the GIA arrangement will be migrated to the new security-constrained dispatch engine as part of the implementation of constrained access (to be delivered under the WA Government's Energy Transformation Strategy), and the GIA tool will be decommissioned.

a. We incrementally increase the Reserve Capacity (over and above the forecast peak quantity determined by WEM Rule 4.5.9(a)) and
b. Repeat steps 1 to 6 until the percentage in Step 4 is less than or equal to 0.002%.

CAPSIM has been run over 250 forced outage iterations (N = 250) to generate a probability distribution of unserved energy and to estimate EUE.

Phase 3: Availability Class Requirements

The forecast Availability Class requirements are developed in accordance with WEM Rule 4.5.12(b) and WEM Rule 4.5.12(c) by 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 WEM Rule 3.18.11) were to apply, then the Planning Criterion would still be met (WEM Rule 4.5.12(b)).

RBP has calculated the minimum generation requirements by simulating unserved energy (for the second and third years of the LT PASA Study Horizon) by repeating the methodology used for the reliability assessment with four differences:

1. First, DSM has been modelled in greater detail to take into account the constraints around the availability of DSM providers[11]. In short, we allocate DSM throughout the year using an optimisation model that dispatches DSM to minimise the peak and subject to scheduling and availability constraints.
2. Second, we specify a planning margin in the model that represents the Ancillary Services Requirement and the Ready Reserve Standard contemplated under WEM Rule 3.18.11 We have modelled a planning margin that varies based on the scaled[12] Capacity Credits of the two largest units.
3. Third, forced outages are taken out of the model. The reason for the removal of forced outages is that the specification of a planning margin on top of forced outages effectively over-estimates the capacity margin[13]. The purpose of the Ancillary Services Requirements and the Ready Reserve Standard is to cover unforeseen events such as forced outages. As such, if there were a

[11] Availability restrictions for DSM are not modelled in the reliability assessment as it is assumed that DSM will be dispatched in any 'last resort' situation, i.e. when there is risk of EUE.

[12] We have used a scaled planning margin as the capacity of the largest unit and the second largest unit will be scaled to meet the RCT in each modelled Capacity Year. The use of an unscaled planning margin, with scaled capacity, would overestimate the contingency implied by the planning margin.

[13] A capacity margin level is an amount of available capacity over demand.

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 Requirements and the Ready Reserve Standard could lead to the overestimation of EUE in a modelled Capacity Year.

4. Finally, for each year of the second and third years of the LT PASA Study Horizon, we iterate the model to reallocate the amount of DSM and generating capacity (reducing the generating capacity as DSM increases, keeping the total capacity capped at the RCT level) until the EUE requirement in WEM Rule 4.5.9(b) is violated.

The level of generation capacity at which the EUE equals 0.002% of expected annual energy consumption then sets the minimum generation capacity.

Phase 4: Availability Curves

The Availability Curves are developed in accordance with WEM Rule 4.5.10(e) by developing a two-dimensional duration curve of the forecast minimum capacity requirements for the second and third Capacity Years of the LT PASA horizon (2021-22, 2022-23). This provides a breakdown of the forecast capacity requirement by Trading Interval and shows the relationship between the RCT and how much capacity is actually required over the relevant Capacity Year.

This is undertaken by scaling the operational profile created in the hourly load forecasting up to the relevant forecast peak demand quantity (consistent with WEM rule 4.5.10(e)(i)), we then convert this hourly demand into the demand for each Trading Interval, assuming that the MW demand in any given half-hourly Trading Interval is the same as the associated hour. Finally, we add the reserve margin, IL allowance and LFAS requirement (as required by WEM rule 4.5.10(e)(ii)).

Phase 5: EDDQ

We forecast the EDDQ using the following approach:

1. First, forecast EUE when DSM is dispatched for zero hours (EUEt,0). This involves repeating the simulation of unserved energy but setting the available capacity of all DSM Facilities to zero. Hence, only generation capacity is available to meet demand as described in WEM Rule 4.5.14C(a).

2. Second, forecast EUE when DSM is dispatched for 200 hours ($EUE_{t,200}$). This involves repeating 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 WEM Rule 4.5.14C(b).

3. Finally, calculate EDDQ in year t as follows:

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

Results

Reliability Assessment

The reliability assessment indicates that for all Capacity Years of the Long Term PASA Study Horizon (2020-21 to 2029-30) the RCT will be set by the forecast peak quantity determined by WEM Rule 4.5.9(a).

Table 1 summarises the results of the reliability assessment. Here we see that the peak forecast component is sufficient to limit expected energy shortfalls to 0.002% of annual energy consumption in all years. Furthermore, the absolute value of EUE is well short of the reliability threshold specified in WEM Rule 4.5.9(a). The EUE estimates from the previous year's modelling are included for comparison.

Table 1: Results of reliability assessment

Capacity Year	RCT (MW)[14]	50% POE peak forecast (MW)	Expected Annual energy consumption (MWh)	0.002% of Expected annual energy consumption (MWh)	EUE (MWh)	EUE as % of expected annual energy consumption	EUE – 2019 ESOO (MWh)
2020-21	4,427	3,774	17,935,419	358.71	0.00	0.0000000%	0.16
2021-22	4,437	3,782	17,539,137	350.78	0.00	0.0000000%	0.02
2022-23	4,421	3,758	17,253,793	345.08	0.00	0.0000000%	0.64
2023-24	4,332	3,707	16,986,658	339.73	0.15	0.0000009%	0.43
2024-25	4,342	3,684	16,828,732	336.57	2.22	0.0000132%	0.14
2025-26	4,383	3,727	16,746,365	334.93	0.00	0.0000000%	0.22

[14] Set by WEM Rule 4.5.9(a) 10% POE + reserve margin +LFAS requirement + IL Allowance

2026-27	4,361	3,719	16,743,152	334.86	0.00	0.0000000%	0.02
2027-28	4,378	3,733	16,793,621	335.87	1.06	0.0000063%	0.80
2028-29	4,327	3,683	16,888,850	337.78	1.45	0.0000086%	0.20
2029-30	4,356	3,720	17,033,731	340.67	1.92	0.0000113%	N/A

Total EUE in this year's modelling is higher than the previous year but remains low. EUE in earlier years is comparable to last year, with a noticeable increase from 2024-25 onwards. This is due to two factors:

- The retirements of Muja_G5 and Muja_G6 (from the start of 2022-23 and 2024-25 respectively) lead to a higher proportion of intermittent generation in the remaining generation mix (note that the total capacity remains the same as total capacity is scaled to meet the RCT, see Appendix A.2). This leads to a lower capacity margin (the difference between total available capacity and hourly load) in winter periods (where most intermittent generation is unavailable) and increases the likelihood of unserved energy in those months, especially in later years with higher loads in winter (see Appendix A.4.5).
- The forced outage rates (FORs) for many large thermal units are materially higher than in the previous year (See Appendix A.3.2). This means that a higher proportion of generation may be on outage when the capacity margin is low, increasing the likelihood of unserved energy.

Availability Class Requirements

The Availability Class Requirements for Capacity Years 2021-22 and 2022-23 are summarised in Table 2 below:

Table 2: Availability Curve, 2021-22 and 2022-23 (MW)

	2021-22	2022-23
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1		
Minimum capacity	3,557	3,371
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2		
DSM	880	1050
RCT	4,437	4,421

Availability Curves

The Availability Curves are illustrated in Figure 2 and Figure 3:

Figure 2: 2021-22 Capacity Year Availability Curve

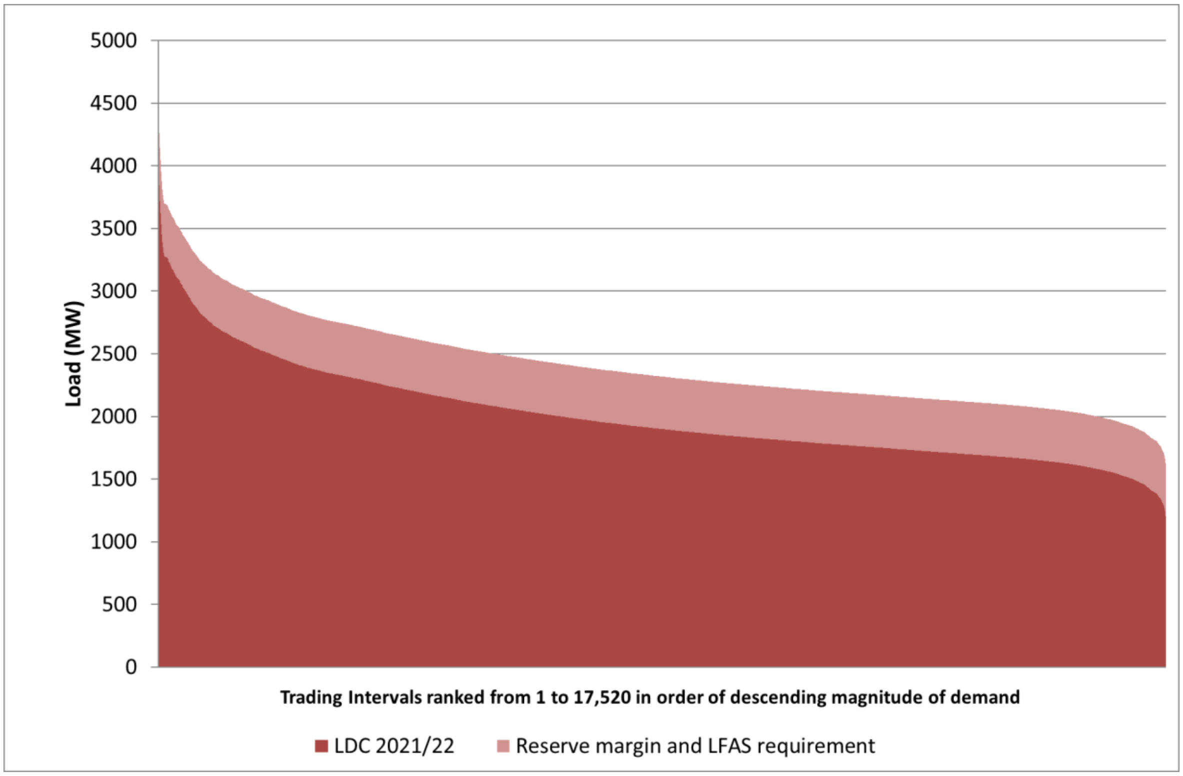
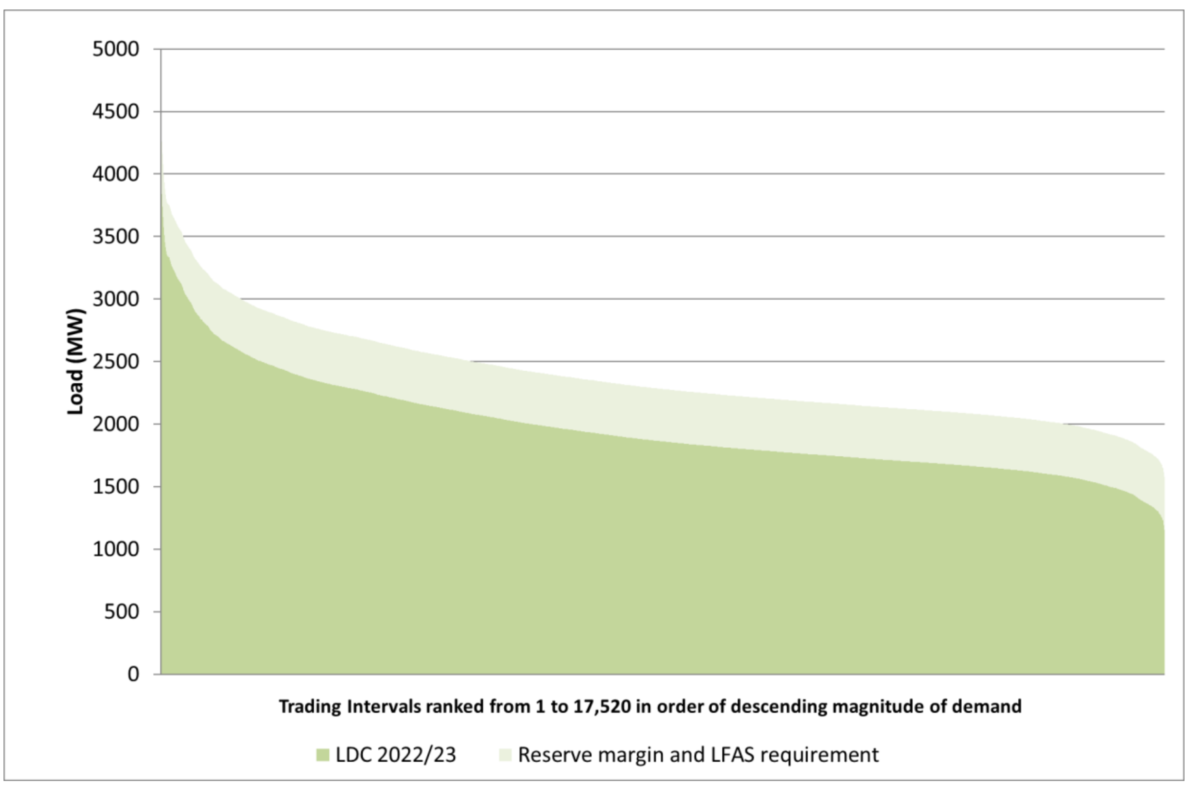


Figure 3: 2022-23 Capacity Year Availability Curve



EDDQ

The EDDQ results are summarised in Table 3. This also provides the resulting DSM Reserve Capacity Price (RCP) calculated based on the DSM Activation Price of $33,460/MWh[15].

Table 3: EDDQ results

Capacity Year	EUE (t,0) (MWh)	EUE (t,200) (MWh)	DSM Capacity Credits (t) (MW)	EDDQ (t) (MWh)	DSM RCP ($/MW)	DSM RCP (2019) ($/MW)
2020-21	0.000	0.000	66	0.000	$16,730.00	$16,820.85
2021-22	0.000	0.000	84.5	0.000	$16,730.00	$16,842.34
2022-23	0.060	0.000	86	0.001	$16,753.53	$16,942.12
2023-24	0.662	0.161	86	0.006	$16,924.99	$16,964.42
2024-25	5.136	2.444	86	0.031	$17,777.33	$16,846.40
2025-26	0.312	0.000	86	0.004	$16,851.49	$16,930.76
2026-27	1.290	0.149	86	0.013	$17,173.69	$16,755.15
2027-28	4.179	1.068	86	0.036	$17,940.42	$17,363.10
2028-29	5.364	1.508	86	0.045	$18,230.26	$16,822.07
2029-30	8.143	2.089	86	0.070	$19,085.14	N/A

[15] As specified in WEM Rule 4.5.14F; the DSM Activation Price represents the Value of Customer Reliability (VCR) for a given Capacity Year. A VCR study is yet to be undertaken, so AEMO has determined the DSM Activation Price to be $33,460/MWh in accordance with clause 4.5.14F of the WEM Rules, based on the VCR in the NEM.

TABLE OF CONTENTS

1 INTRODUCTION

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

- Undertake the reliability assessment and development of the Availability Curve and Availability Classes for the South West interconnected system (SWIS)
- Forecast the Expected DSM Dispatch Quantity (EDDQ) in accordance with clause 4.5.14A of the Wholesale Electricity Market Rules (WEM Rule 4.5.14A) and the Market Procedure: Determination of the Expected DSM Dispatch Quantity and the DSM Activation Price.

This report contains our:

- Modelling methodology and assumptions.
- Draft results.

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 AEMO undertakes a Long Term Projected Assessment of System Adequacy (LT PASA). The results of the LT PASA analysis feed into AEMO's Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) report. The LT PASA forecasts:

- The Reserve Capacity Target (RCT) for each year in the LT PASA study (WEM Rule 4.5.10(b)) and the Reserve Capacity Requirement (WEM Rule 4.6.1). The RCT is set to meet the Planning Criterion which is defined in WEM Rule 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 (WEM Rule 4.5.9(a)) and
  - A reliability component to ensure expected energy shortfalls are limited to 0.002% of annual energy consumption (WEM Rule 4.5.9(b)).
- Generation capacity and Demand Side Management (DSM) requirements in the form of the Availability Classes, which is defined by WEM Rule 4.5.12.
- The Availability Curve to determine the minimum capacity requirement for each Trading Interval in the Capacity Year, which is defined by WEM Rule 4.5.10(e).

Additionally, WEM Rule 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 modelling exercise is to:

- Undertake a reliability assessment to ensure the RCT is compliant with WEM Rule 4.5.9(b)
- Develop the Availability Curve defined by WEM Rule 4.5.10(e).
- Determine the minimum capacity required to be provided by Availability Class 1[16] and the capacity associated with Availability Class 2[17], defined by WEM Rule 4.5.12.
- Forecast the EDDQ defined by WEM Rule 4.5.14A.

1.2 Scope of Modelling

Our modelling covers:

- The reliability assessment for the 2020 Reserve Capacity Cycle covering Capacity Years 2020-21 to 2029-30
- The Availability Curve and Availability Class Requirements for the second and third year of the 2020 Reserve Capacity Cycle (2021-2022 and 2022-23).
- The EDDQ covering Capacity Years 2020-21 to 2029-30.

1.3 Structure of This Report

The remainder of our report is structured as follows:

- Our modelling methodology is described in Chapter 2
- The results of the modelling are presented in Chapter 3
- The assumptions underlying our modelling can be found in APPENDIX A

[16] The minimum generation capacity required if all DSM were activated to meet the reliability component of the Planning Criterion (WEM Rule 4.5.9(b)) and ensure the outage scheduling requirements set by WEM Rule 3.18.11 are met.

[17] Capacity not expected to be available for dispatch for all trading intervals (i.e. DSM).

2 MODELLING METHODOLOGY

2.1 OVERVIEW OF MODELLING APPROACH[18]

Our modelling has five phases:

- **Phase 1: Hourly Load Forecasting**. Forecasting the hourly underlying load trace over the LT PASA study horizon, taking into account the annual 50% Probability of Exceedance (POE) summer peak forecast, expected annual energy consumption forecasts and hourly DER contribution.
- **Phase 2: Reliability Assessment.** Simulating expected unserved energy (EUE) over the LT PASA Study horizon to apply the second component of the Planning Criterion (WEM Rule 4.5.9(b)) and determine the amount of Reserve Capacity required to limit expected energy shortfalls to 0.002% of forecast annual energy consumption. This will enable AEMO to determine the RCT for each year in the LT PASA Study Horizon.
- **Phase 3: Availability Class Requirements.** Determining the Availability Class requirements contemplated by WEM Rules 4.5.12(b)[19] and 4.5.12(c)[20] and
- **Phase 4: Availability Curves**. Developing the two-dimensional duration curves required under WEM Rule 4.5.10(e)
- **Phase 5: EDDQ**. Determining the EDDQ for each Capacity Year of the LT PASA Study Horizon.

2.2 PHASE 1: HOURLY LOAD FORECASTING

In previous years we have developed a 'reference' load profile (load shape and load chronology[21]) from historical operational[22] load data and scaled that profile according to the peak demand and

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[18] The peak demand and energy consumption forecasts applied for all phases of the modelling are developed under the expected demand growth scenario.

[19] The capacity associated with Availability Class 1.

[20] The capacity associated with Availability Class 2.

[21] The chronology (periods) of a Capacity Year, indexed and ranked in descending order of load.

[22] With electrical energy supplied by behind the meter PV netted off.

annual energy forecasts from AEMO. In practice, this has meant that the load shapes varied little year from year and importantly, the load chronology did not vary over time (i.e. the day/time associated with the peak period in the historical data would be the same in all modelled Capacity Years).

In recent years, we have seen significant changes in load profiles, with lower off-peak loads and peak demand occurring later in the day. These changes have been driven by the increasing penetration of distributed energy resources (DER)[23] and in particular, behind-the-meter (BTM) PV generation. This trend is expected to continue across the modelling horizon, and we would expect further changes to the load profile in future years. This means that maintaining the same load chronology and shapes across all modelled years may not provide an accurate representation of load profiles in the future.

Reflecting this, we have updated our load forecasting methodology to explicitly forecast the load profile for each individual Capacity Year (and allowing year-on-year variation), based on AEMO's forecasts of future DER growth and underlying demand. This is done by creating hourly underlying demand forecasts[24], and subtracting hourly forecasts of BTM PV and battery storage contribution to create preliminary hourly operational forecasts, which is converted into a load profile. This load profile is then scaled to ensure alignment with the forecast operational 50% POE summer peak and annual sent-out energy consumption forecasts provided by AEMO.

Our approach to forecasting the load profile has five steps:

i. Create the underlying load profile: The underlying load shape has been developed using historical sent out generation data (adding historical BTM PV generation to get underlying load) to derive an average load shape; this has been applied to the 2018-19 load chronology (i.e. the hour with the largest underlying load in 2018-19 is the hour with the largest underlying load in our forecasts and likewise for the 2nd, 3rd - 8760th hour) to create the underlying reference load profile.
ii. Scale the underlying load profile to forecasted values: Hourly underlying load forecasts for each year in the LT PASA Study Horizon have been developed by scaling up the underlying reference load profile to match the underlying 50% POE peak and expected energy forecasts for the respective Capacity Year.

[23] This includes BTM PV and battery storage, but not electric vehicles.

[24] Based on historical data and AEMO's underlying peak/energy consumption forecasts.

iii. Forecast hourly DER contribution: Using DER data provided by AEMO, we forecast hourly BTM PV generation (averaged across five 'outage sequences' reflecting stochastic weather and cloud cover), and battery charge/discharge, for each Capacity Year.

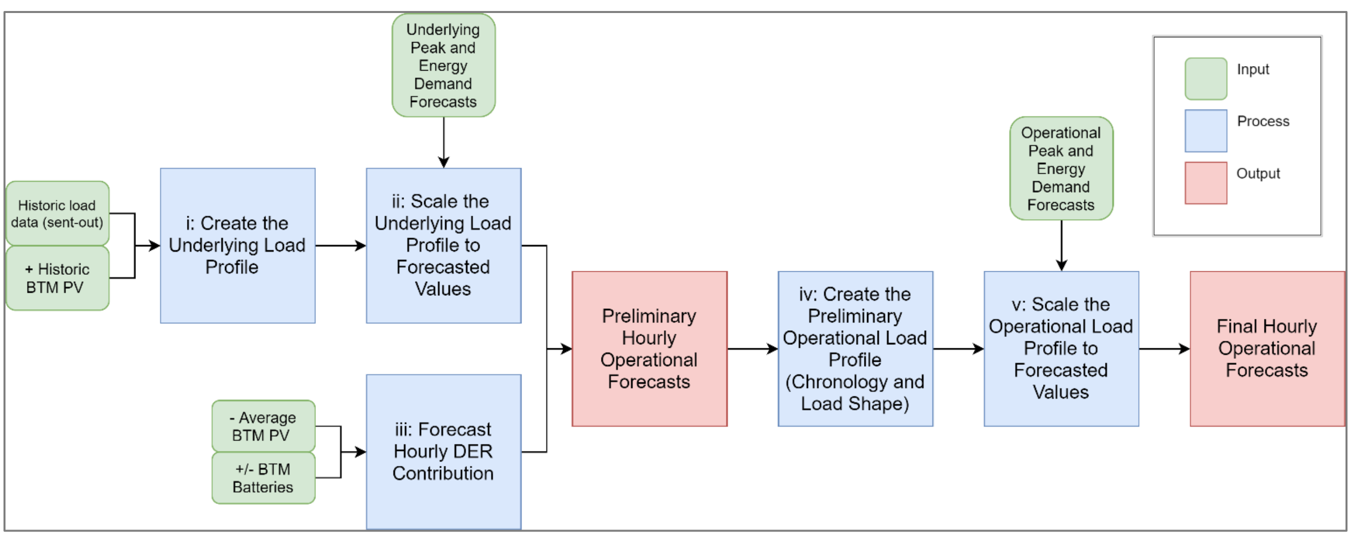
iv. Create the preliminary operational load profile (chronology and load shape): The hourly underlying load forecasts and hourly DER contribution forecasts have been combined and adjusted for losses to create hourly operational load forecasts. These are processed into an operational load profile for each Capacity Year.

v. Scale the operational load to forecasted values: In order to ensure that our hourly operational load forecasts align with the operational peak and annual energy consumption forecasts provided by AEMO we have scaled the operational load profile to forecasted values, producing the final hourly operational load forecasts to be used in the modelling.

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

Figure 4 provides an overview of the load forecasting process. Boxes in green reference inputs, boxes in blue reference each step in the process (described in more detail in Sections 2.2.1 - 2.2.5), while red boxes refer to outputs.

Figure 4: Overview of load forecasting process



These hourly load forecasts are key inputs into both Phases 2 and 3. Specifically:

- They are used as the hourly load across the modelling horizon for the modelling component of the reliability assessment
- They are also used to derive the two-dimensional duration curve defined in WEM Rule 4.5.10(e), which is developed by adjusting further the scaled profiles (in Section 2.4) to

incorporate the requirements of WEM Rule 4.5.10(e). This is addressed in further detail in Section 2.5.1.

2.2.1 Creating the Underlying Load Profile

We have developed a 'reference' underlying load profile by constructing underlying historical load duration curves (LDCs)[25] for the last five full Capacity Years (2014-15 to 2018-19), averaging across these five LDCs to construct an average load shape, and applying this underlying average load shape to the most recent underlying load chronology (2018-19). As the historical total sent-out generation from AEMO reflects operational demand and will include the effects of BTM PV generation, we add historical BTM PV generation[26] (provided by AEMO) to the historical operational load data[27] before conducting the above analysis.

We have used the average load profile to ensure that the underlying demand profile reflects a representative underlying load shape, while ensuring that more recent trends are captured[28].

2.2.2 Scaling the Underlying Load Profile to Forecasted Values

The next step in our load forecasting methodology is to scale the reference underlying load profile to match the underlying 50% POE peak forecast and expected demand in any given year.

This year, the underlying 50% POE forecasts provided by AEMO represent the underlying demand occurring at the time of the forecast operational peak, rather than the maximum underlying demand over the forecast Capacity Year.

Historically, the underlying peak demand and the operational peak demand generally occur on the same day. However, the underlying peak demand occurs earlier in the day and will be higher than the underlying demand occurring at the time of operational peak. AEMO has provided the time of operational peak for each forecast year and we have scaled up the underlying values provided by AEMO to represent the underlying 50% POE peak. This scaling is designed to represent the average historical difference between the underlying demand occurring at the time of the operational peak

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[25] A load curve ordered in order of descending demand magnitude.

[26] BTM PV generation will cause total sent generation to be lower than underlying demand.

[27] This is based on the Total Sent Out Generation data provided by AEMO.

[28] Note that our historical underlying load chronology does not include the recent 2019-20 summer peak (which was particularly high and occurred on 4 February 2020) and would lead to relatively higher summer loads in the historical load profile. This peak was primarily driven by very hot temperature conditions leading to high underlying demand (with a maximum temperature of 43°C on the peak day, after two consecutive hot days of over 35°C).

demand and the actual underlying peak demand. For more details on this process, see Appendix A.4.2.

Having scaled the underlying demand value occurring at the time of forecast operational peak to the underlying peak, for each year of the LT PASA forecast horizon we have produced a forecasted underlying load profile with a shape such that:

- The peak of the load profile equals the underlying 50% POE forecast
- The load allocated across all hours sums to the expected underlying annual energy consumption forecast and
- The shape of the profile should be "close" to the reference year underlying load profile developed above.

We have defined a function F(h) (h ∈ hours of the year), such that the shape of underlying profile for a given year t ($\widehat{PROF}(h)$) can be derived by multiplying the average load shape ($\overline{PROF}(h)$) by this function. That is:

- $\widehat{PROF}(h) = F(h) \times \overline{PROF}(h)$, such that:
  - $Max\left(\widehat{PROF}(h)\right)$ = 50% underlying POE peak forecast in year t and
  - $\sum_{h=1}^{8760} \widehat{PROF}(h) =$ underlying expected energy consumption forecast in year t.

The function is defined to ensure that the shape of the profile varies with differing peak/energy ratios in a way that is consistent with the historical load shapes 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 underlying 50% POE peak forecast to the five-year average underlying peak demand
- e denotes the ratio of the underlying expected energy consumption forecast to the five-year average underlying hourly energy consumption
- m denotes the position in the profile in which the curve flattens (1500 for this year’s modelling), as has been observed in 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 profile’s resulting load shape.

This process gives us hourly underlying demand forecasts across the modelling horizon.

2.2.3 Forecasting Hourly DER Contribution:

Our DER forecasts are the sum of the following data:

- BTM PV generation
- BTM battery charging and discharge demand

Each component has a separate methodology which is discussed below. These methodologies produce hourly forecasts which are aggregated together to produce hourly DER contribution for each Capacity Year over the modelling horizon. Note that as EVs are already included in the forecasts from AEMO, we have not modelled these separately.

Behind the Meter PV Generation and Outages

The profile of BTM PV generation is complex, with seasonal and daily variability and random intermittency caused by cloud cover. For the purpose of modelling, this can be broken down into:

- Daily generation potential profiles for each month of the year, assuming zero cloud cover (we have assumed that the 99.5% percentile generation in a given month, hour, represents a unit generating at its maximum capacity with zero cloud cover). These are deterministic (i.e. fixed and predictable) profiles and are expressed as capacity factors (i.e. fraction of installed capacity).
- BTM PV capacity forecasts (MW) over the modelling horizon.
- An outage probability distribution function (PDF), expressing the probability that a given unit of generation output will be eliminated by cloud cover. This PDF is dependent on the outage (i.e. cloud cover) in the previous hour, and this dependency needs to be factored in to avoid excessive changes in solar PV output from one period to the next. These factors have been developed from historical capacity factors, analysing actual generation compared to forecasted generation and 'adding features' to the PDF as necessary, validating it against historical generation. This dependency is also a function of the season of the year. Therefore, PDFs have been computed for a range of previous hour outage factors and each season (summer, winter and shoulder).

AEMO has provided historical BTM PV capacity factor data for each Trading Interval from 1 January 2010 to 23 February 2020[29]. Using statistical analysis (comparing actual generation to zero cloud cover generation in a period, and processing this into percentiles) of the historical data, we have

[29] Sourced from Solcast.

processed this into daily generation profiles for each month and outage PDFs, as described above. AEMO has also provided installed capacity forecasts over the modelling horizon.

These three factors have been combined to simulate a realistic solar generation profile by:

1. For each modelled hour, selecting the generation potential value.
2. For each modelled hour, randomly generating an outage factor from the PDFs. This is done by generating a random number for each modelled hour. This random number looks up the cumulative PDF for the relevant season, for the relevant previous outage factor, which gives the modelled hour's outage factor.
3. Multiplying these two factors by the forecast BTM PV capacity (MW) for the period, to obtain a MWh generation value.

We have used five outage seeds to provide a range of potential BTM PV generation sequences. In order to vary BTM PV outages, we simply change the random outage seed and regenerate the random numbers, which then selects a different outage factor (and consequent generation) for each modelled hour. This gives us five varying PV generation sequences. We then take the hourly average of these sequences.

The average PV generation sequence gives a more robust model of the peak-shifting dynamics we want to consider as the averaging will more likely reflect the underlying conditions driving the peaks shifting, rather than being determined in large part by a given trace's outage sequence.

Behind the Meter Battery Storage

BTM batteries include installations in domestic and commercial properties, but do not include grid-connected storage Facilities.

From AEMO, we have received MW capacity and MWh duration forecasts by year and month for residential and two classes of commercial batteries (up to 100kW and above 100kW).

Normalised historical charge and discharge profiles for residential and commercial batteries, by period and month of year (expressed as a fraction of the installed kW battery capacity) have also been provided by AEMO. We have taken the charge and discharge profile for each period and month of year, over the last ten years (to align with the PV historical data) to create an average profile for the modelling.

The resulting net charge/discharge for a given period in a model year is calculated as:

$$BattNetCD_{y,p} = 1000 \times \left(Charge^{Res}_{M(p),p} - Discharge^{Res}_{M(p),p}\right) \times BatMW^{Res}_{c,y,M(p)} + 1000 \times \left(Charge^{Com}_{M(p),p} - Discharge^{Com}_{M(p),p}\right) \times \left(BatMW^{ComSml}_{c,y,M(p)} + BatMW^{ComLge}_{c,y,M(p)}\right)$$

Where:

$BattNetCD_{y,p}$	is the net battery charge/discharge for period *p* in year *y*
$Charge^{Res}_{m,p}$	is the residential charge profile for month *m*, period *p*
$Discharge^{Res}_{m,p}$	is the residential discharge profile for month *m*, period *p*
$Charge^{Com}_{m,p}$	is the commercial charge profile for month *m*, period *p*
$Discharge^{Com}_{m,p}$	is the commercial discharge profile for month *m*, period *p*
$M(p)$	is the number of the month that period *p* is in
$BatMW^{Res}_{c,y,m}$	is the forecast residential battery capacity in MW
$BatMW^{ComSml}_{c,y,m}$	is the forecast small commercial battery capacity in MW
$BatMW^{ComLge}_{c,y,m}$	is the forecast large commercial battery capacity in MW

This net charge/discharge is a negative value when discharge exceeds charge demand, so reduces the total demand.

2.2.4 Creating the Preliminary Operational Load Profile

In order to create the preliminary operational load profile, we first aggregate our hourly underlying load forecasts with our hourly DER contribution forecasts to create hourly delivered (non-loss adjusted) load forecasts, such that:

$$DL_d = UL_d - DER_d$$

Where DL_d refers to the delivered load at datetime d, UL_d refers to the underlying load forecasts and DER_d refers to the hourly DER contributions. The delivered loads are then loss-adjusted by a weighted loss factor, calculated from a residential loss factor and a business loss factor provided by AEMO, and the relative proportion of forecasted underlying residential to business annual energy consumption, such that:

$$OL_d = DL_d \times \left(\left(LF_r \times \frac{L_r}{L_r + L_b}\right) + \left(LF_b \times \frac{L_b}{L_r + L_b}\right)\right)$$

Where OL_d refers to the operational load at datetime d, LF_r, LF_b refers to the residential and business loss factors (respectively), and L_r,L_b refers to total forecast underlying residential and business load/demand for a given Capacity Year.

These preliminary operational load hourly forecasts are then aggregated into the operational load profile for each Capacity Year by:

- Converting the load values into a load shape by expressing each load value as a percentage of maximum demand, ranking these in descending order (largest to smallest)
- Indexing the load shape by its associated date in the hourly forecasts to create a load chronology

This give us a preliminary operational load profile for each forecast Capacity Year.

2.2.5 Scaling the Operational Load Profile to Forecasted Values

Analysis of the preliminary operational load forecasts created in Section 2.2.4 has shown that in some cases the derived operational peak demand and annual energy consumption from our forecasts may not exactly match the forecasts provided by AEMO. This is for three reasons:

- The 50% peak demand provided by AEMO does not necessarily match the expected annual energy consumption, as these may reflect different underlying demand conditions.
- The methodology used by AEMO to create the 50% POE forecasts relies on many iterations of BTM PV generation so the likelihood of one of our PV outage sequences exactly corresponding with AEMO's is low.
- The methodology used in forecasting battery charge/discharge by AEMO in producing their forecasts is not exactly reproducible by RBP, as it is a function of the PV simulations.

Given that the peak forecasts provided by AEMO set the RCT and consequently forms the basis of the reliability modelling, it is important that the peaks we use for our modelling match those provided by AEMO. In order to ensure this, we have re-scaled the operational load profile created in Section 2.2.4, using the function described in Section 2.2.2. This give us hourly load forecasts that capture year-on-year variation in load shape and chronology, while maintaining alignment with the 50% POE operational peak demand and expected annual operational consumption forecasts provided by AEMO.

2.3 Phase 2: Reliability Assessment

We have used our bespoke model, CAPSIM[30] to conduct the reliability assessment. CAPSIM simulates the capacity gap (a simple arithmetic calculation subtracting load from available generation capacity) for every hour[31] of every year, sequentially, given a specific generation mix, load profile, planned outage schedule and random forced outages. Generator Interim Access (GIA)[32] constraints have been modelled to ensure available GIA generation is constrained down when a constraint is binding.

The purpose of this phase is to assess the amount of Reserve Capacity required to limit expected energy shortfalls to the Planning Criterion set by WEM Rule 4.5.9(b) (0.002% of annual energy), in doing this we follow the subsequent steps:

1. For each year of the Long Term PASA Study Horizon, we assume Reserve Capacity (generating capacity and DSM) equals the forecast peak quantity plus the reserve margin, Intermittent Load (IL) allowance and Load Following Ancillary Services (LFAS) quantity determined by WEM Rule 4.5.9(a).
2. For the hourly load forecast (see Section 2.2), based on assumptions of the availability of intermittent generation (see Section 2.3.3), planned outages (see Section 2.3.4) and randomised forced outages (see Section 2.3.5), we simulate the capacity gap (the difference between available capacity and load) in CAPSIM. Each iteration yields an estimate of unserved energy.
3. We then use the N iterations above to estimate Expected Unserved Energy (EUE) as follows:

$$\mathrm{EUE}_{\mathrm{loadforecast}_t} = \frac{1}{N}\sum_{i=1}^{N} Unserved\ Energy_{i,t}$$

   $\mathrm{EUE}_{\mathrm{loadforecast}_t}$ denotes the estimate of EUE simulated by CAPSIM, using the underlying peak energy and DER forecasts for year t.

4. We then calculate this average EUE as a percentage of annual energy consumption.

---

[30] CAPSIM is developed in Python, utilising the open-source packages Pandas and NumPy for tabular processing and vectorised operations.

[31] Note that CAPSIM does not consider intra-hour demand variability as very short-term fluctuations in demand will be covered by the dispatch of Ancillary Services.

[32] The GIA arrangement was developed to facilitate new generation connections on a constrained basis. It is not scalable and was intended as an interim solution. Generators connected under the GIA arrangement will be migrated to the new security-constrained dispatch engine as part of the implementation of constrained access (to be delivered under the WA Government's Energy Transformation Strategy), and the GIA tool will be decommissioned.

5. If the percentage in Step 4 is less than or equal to 0.002% then we stop; the RCT will be set by the first component of the Planning Criterion (WEM Rule 4.5.9(a)).
6. If the percentage is greater than 0.002%, then:
   a. We incrementally increase the Reserve Capacity (over and above the forecast peak quantity determined by WEM Rule 4.5.9(a)) and
   b. Repeat steps 1 to 6 until the percentage in Step 4 is less than or equal to 0.002%.

CAPSIM has been run over 250 forced outage iterations to generate a probability distribution of unserved energy and to estimate EUE over the modelling horizon.

The above steps are a high-level summary of our modelling methodology for the reliability assessment. In the remainder of this section, we provide a more detailed description of the modelling. Specifically, the following sections outline how Steps 2 and 3 have been implemented in practice.

The rest of this section is structured as follows:

- We first provide an overview of CAPSIM in Section 2.3.1
- We then an overview of our approach to modelling GIA constraints in Section 2.3.2
- We then discuss how intermittent generation and outages have been modelled in CAPSIM in Section 2.3.3
- We then explain our methodology for developing a planned outage schedule in Section 2.3.4
- Finally, we describe our approach towards modelling forced outages in Section 2.3.5

2.3.1 Overview of CAPSIM

We have developed a bespoke model (CAPSIM) in Python to complete the reliability assessment. This model compares the total available capacity in each hour across the Long Term PASA modelling horizon and compares it to the corresponding load.

Total available capacity takes into account planned outages, intermittent generation, the GIA constraints and randomly sampled forced outages. Unserved energy occurs whenever load is greater than total available capacity in a period.

CAPSIM has been run over multiple iterations with varying random number seeds for forced outages, to generate a probability distribution of unserved energy and to estimate EUE.

2.3.2 Application of GIA constraints

We have implemented the full set of GIA constraints in every hour, substituting available capacity[33] into the constraint coefficients. The methodology is as follows:

- Step 1: The full set of constraints are inputted into the CAPSIM model (noting that all constraints are of a <= nature, with all GIA generation on the left hand side (LHS) and load and non-GIA generation on the right hand side (RHS).
- Step 2: CAPSIM calculates a scaling factor, for each constraint, for each period, in each iteration:

$$Scaling_{cpi} = \begin{cases} 1 - \dfrac{(LHS_{cpi} - RHS_{cpi})}{GIA_{cpi}} & if\ LHS_{cpi} > RHS_{cpi} \bigcap LHS_{cpi} - RHS_{cpi} < GIA_{cpi} \\ 0 & if\ LHS_{cpi} > RHS_{cpi} \bigcap LHS_{cpi} - RHS_{cpi} \geq GIA_{cpi} \text{ [34]} \\ 1 & if\ LHS_{cpi} \leq RHS_{cpi} \end{cases}$$

Where:

- LHS_{cpi} refers to the constraint coefficients on the LHS applied to the relevant GIA generators' capacities
- $LHS_{cpi} = \sum_{g \in GIA\ generators\ appearing\ in\ Constraint\ c} GIAcoefficient_{g,c} \times GIACapacity_g$
- RHS_{cpi} refers to the constraint coefficients on the RHS multiplied through the applicable non-GIA generator's capacity, a load multiplier (multiplied by a period's load) and the constraint constant, summed together
- $RHS_{cpi} = \sum_{ng \in nonGIA\ generators\ appearing\ in\ Constraint\ c} nonGIAcoefficient_{g,c} \times nonGIACapacity_g + Load_p \times LoadCoefficient_c + Constant_c$
- GIA_{cpi} refers to the sum of the capacity of all GIA generators appearing in constraint c.
- $0 \leq Scaling_{cpi} \leq 1$ refers to the scaling factor for constraint *c* in period *p* in iteration *i*. In other words:

[33] The use of capacity is valid due to the implications of the must-offer rule described in the WEM Rules. In other words, unserved energy can only occur when total load is more than total available capacity. If a GIA constraint binds when generators are not generating at their full capacity, then this is irrelevant for our analysis as unserved energy would not occur under these conditions. The only condition relevant for our analysis is where backing-off a GIA generator due to a binding GIA constraint causes unserved energy. Under such circumstances, all available non-GIA generators would have to be generating at full capacity due to the must-offer rule.

[34] This condition is applied to ensure that in the event $(LHS_{cpi} - RHS_{cpi}) > GIA_{cpi}$, we do not apply a negative scaling factor. In this circumstance, all GIA generation would need to be scaled down to 0 as the amount of generation required to meet the constraint exceeds the amount of available generation capacity.

If the LHS<=RHS, the constraint is not binding (or just binding) and we get a scaling factor of 1 (i.e. GIA generation does not need to be constrained down, as the constraint has not been violated).

If the LHS>RHS, the constraint has been violated and $0 \leq Scaling_{cpi} < 1$; this means GIA generation needs to be constrained down.

- Step 3: Finally, we determine which scaling factor should be applied to each GIA generator (in each period and iteration) by selecting the minimum scaling factor calculated for that GIA generator across all constraints it appears in. GIA generators are then de-rated by the minimum scaling factor observed across the constraints.

2.3.3 Treatment of Intermittent Generation

We have used historical generation for existing Facilities[35] and Market Participant provided estimated generation for new Facilities to develop intra-day hourly generation profiles for a given month as follows:

- For each month (Jan, Feb, ..., Nov, Dec), we assign an intra-day hourly profile to each intermittent generator.
  - This means each intermittent generator has 12 intra-day hourly profiles (one for each month of the year).
- Hence, $\overline{Gen_{h,m}} = \frac{1}{T}\sum_{Y\ (Years)=1}^{T}\left(\frac{\sum_{d\ (days)\in Month\ m} Gen_{Y,h,d}}{\#\ days\ in\ month\ m\ of\ Year\ Y}\right)$
- For a given intermittent generator:
  - $\overline{Gen_{h,m}}$ denotes the average generation (MW) in hour h of month m (based on T years of historical or Market Participant provided generation values)
  - $Gen_{Y,h,d}$ denotes the historical or estimated generation value in hour h or day d (in month m) of Year Y.

This approach captures both intra-day and seasonal variation, while ensuring the average hourly generation values are based on a sample size large enough (at least five years of data) to yield robust generation estimates.

Note that the $\overline{Gen_{h,m}}$ value for a given intermittent generator has been scaled to reflect the ratio of the RCT to total Capacity Credits.

[35] Based on their non-loss adjusted metered quantities

2.3.4 Planned Outages

For planned outage scheduling, we have used Market Participant provided scheduled outage dates[36] as a starting point but have then evaluated these outages to ensure that the planning margin contemplated under WEM Rule 3.18.11 would be met if all proposed planned outages were allowed to proceed[37].

We have compared weekly peak load forecasts derived from the final operational hourly load forecast described in Section 2.2 to the Medium Term (MT) PASA second deviation weekly peak load forecasts[38] (which is used by System Management to approve outages), where the horizons[39] for these two forecasts overlap. This allows us to develop scaling factors reflecting the average difference between the LT PASA and MT PASA forecasts, by year and season.

We have then scaled up our weekly peak load forecasts as follows:

- For Capacity Years that match up with the MT PASA horizon (2020-21, 2021-22 and early 2022-23), we have scaled the hourly operational load forecasts created in 2.2.5 using the seasonal and annual scaling factors described above.
- For Capacity Years outside of the MT PASA horizon (late 2022-23 onwards) we have used the scaling factors derived for the latest season for which MT PASA forecasts are available (i.e. Q3, Q4 - 2022-23, and Q1, Q2 - 2023-24).

The purpose of this scaling is to ensure that we use a weekly peak load forecast for planned outage scheduling that is sufficiently conservative. As our load forecasting process focuses on correctly determining peak demand over the entire year, weekly peaks in our load forecasts (and in particular, during weeks with lower demands) tend to be slightly lower than that in the MT PASA. Table 4 shows the average percentage difference between the two forecasts[40]:

[36] The information was collected by AEMO through the information request process in accordance with WEM Rule 4.5.3.

[37] Note that this approach is not designed to exactly replicate the process System Management uses to approve planned outages under WEM Rule 3.18.11; instead it is intended to remove concurrent planned outages which would not be allowed under real operating conditions.

[38] https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/projected-assessment-of-system-adequacy-pasa/medium-term-pasa-reports

[39] The MT PASA horizon is only three years from publication so this cannot be used over the entire LT PASA horizon.

[40] Note that the percentage differences are generally higher than last year. This is due to lower off-peak periods with the increasing penetration of BTM PV.

Table 4: Average percentage difference between MT PASA and 2020 WEM ESOO weekly peak load forecasts

Quarter/ Calendar Year	2020	2021	2022	2023
Jan-Mar	N/A	21.37%	24.59%	22.96%
Apr-Jun	N/A	6.64%	8.62%	16.53%
Jul-Sep	N/A	1.16%	2.08%	N/A
Oct-Dec	22.06%	25.89%	26.09%	N/A

The planned outage scheduling is conducted as follows:

1. Subtract the weekly peak load (as derived above) from available generation[41] to calculate a capacity margin reflecting the amount of generation available above needed levels.
2. If the capacity margin is greater than the planning margin, then we have used the Market Participant provided planned outage inputs (and zero out the relevant Facility's capacity on those dates).
3. If the capacity margin is less than the planning margin, we have moved the Market Participant provided planned outage inputs to meet the outage evaluation criteria, while ensuring that the timing of the outage request is similar to what the Market Participant has requested. As above, we zero out the relevant capacity on the amended dates.

Following previous years, we have not modelled opportunistic maintenance. This is because opportunistic maintenances are subject to System Management's evaluation process, whereby an outage will not be approved if it violates the requirements in Section 3.18 of the WEM Rules. Furthermore, no planned outage would proceed in a period with a tight margin and a non-trivial risk of unserved energy.

2.3.5 Forced Outages

Forced Outages have been randomised by:

- Determining a forced outage probability for each generator.
- Inputting these probabilities into CAPSIM which then randomly assigns plant outages in a sampled hour based on the specified probability for a given iteration.

[41] Total generation less capacity on planned outages (as provided by Market Participants). Intermittent generation is de-rated based on seasonal profiles to reflect available generation.

CAPSIM has generated 250 sequences of forced outages for each generator across the modelling horizon.

Our forced outage assumptions have been developed using historic forced outage data and are presented in Appendix A.3.2.

2.4 Phase 3: Availability Class Requirements

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

In this section, we outline the methodology used to determine the Availability Class requirements (WEM Rule 4.5.12(b) and 4.5.12(c))

2.4.1 Determine WEM Rule 4.5.12(b)

WEM Rule 4.5.12(b) requires the determination of the minimum generation 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;

RBP has calculated the minimum generation requirement by simulating unserved energy (for the second and third years of the LT PASA Study Horizon) as described in Section 2.3 with four differences:

1. First, DSM has been modelled in greater detail to take into account the constraints around the availability of DSM providers[42]. In short, we allocate DSM throughout the year using an optimisation model that dispatches DSM to minimise the peak subject to scheduling and availability constraints. See below for further details on our approach to modelling DSM.
2. Second, we specify a planning margin in the market model that represent the Ancillary Services requirement and Ready Reserve Standard contemplated in WEM Rule 3.18.11. We have modelled a planning margin that varies based on the scaled[43] Capacity Credits of the two largest units (see Appendix A.5).
3. Third, forced outages are taken out of the model. The reason for the removal of forced outages is that the specification of a planning margin on top of forced outages effectively over-estimates the capacity margin. The purpose of the Ancillary Services Requirement and Ready Reserve Standard 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 and Ready Reserve Standard could lead to the overestimation of EUE in a modelled Capacity Year.
4. Finally, for each year of the relevant Reserve Capacity Cycle, we iterate the model to reallocate the amount of DSM and generating capacity (reducing the generating capacity as DSM increases, keeping the total capacity capped at the RCT level) until the EUE requirement in WEM Rule 4.5.9(b) is violated.

---

[42] Availability constraints for DSM are not modelled in the reliability assessment as it is assumed that DSM will be dispatched in any 'last resort' situation, i.e. when there is risk of EUE.

[43] We have used a scaled planning margin as the capacity of the largest unit and the second largest unit will be scaled to meet the RCT in each modelled Capacity Year. The use of an unscaled planning margin, with scaled capacity, would overestimate the contingency implied by the planning margin.

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

DSM Modelling Methodology

DSM in the WEM is subject to availability constraints[44]. RBP has forecasted hourly DSM dispatch by allocating available DSM throughout the year based on an optimisation model that takes into account these constraints. Our approach is detailed further below:

1. First, forecast sequential hourly load for the year using the methodology described in Section 2.2.
2. Second, use a spreadsheet-based optimisation model which, given the forecasted hourly load, dispatches DSM Facilities (excluding Interruptible Load as that is excluded under WEM Rule 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, iteratively dispatching the DSM quantities to minimise the peak load, across all periods, each iteration is tested against the dispatch constraints, with each iteration moving towards the optimal[45] dispatch with the lowest overall peak load.
3. Finally, adjust the load profile used in the market modelling by subtracting the forecasted DSM dispatch in the relevant hours (from Step 1 above). This adjusted load profile represents the "effective demand" and is used in the modelling of the minimum generation capacity contemplated by WEM Rule 4.5.12(b).

2.4.2 Determine WEM Rule 4.5.12(c)

WEM Rule 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).*

---

[44] As specified in WEM Rules 4.10.1(f).

[45] 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 produces 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.

This is a straightforward calculation that is computed by:

1. Subtracting the minimum generation capacity, calculated above (see Section 2.4.1, Determine WEM Rule 4.5.12) from;
2. The RCT for the relevant Capacity Year (see Table 5)

2.5 Phase 4: Availability Curves

WEM Rule 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. This provides a breakdown of the forecast capacity requirement by Trading Interval and shows the relationship between the RCT and how much capacity is required in other Trading Intervals

In this section, we outline the methodology used to determine the two Availability Curves (WEM Rule 4.5.10(e)).

2.5.1 Determine WEM Rule 4.5.10(e)

WEM Rule 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 WEM Rule 4.5.10(e)(i) and the load scenario contemplated in WEM Rule 4.5.10(a)(iv) in deriving the LDC above was undertaken in consultation with 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 scenario) 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.

Our approach to determining this quantity is summarised below.

1. We use the operational peak demand and expected annual operational consumption forecasts (from AEMO) to forecast the LDC for a given year as specified in WEM Rule 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 under the expected demand growth scenario (i.e. the load scenario contemplated in WEM Rule 4.5.10(a)(iv)). This has been done using the operational load profile developed in Section 2.2.4, scaling this profile up to the 10% POE operational peak forecasts provided by AEMO using the same process described in Section 2.2.5.
   b. We then estimate the forecast load for the remaining hours (hours 25-8,760) hours assuming a 50% POE peak forecast under the expected demand growth scenario (i.e. the load forecasts created in Section 2.2.5).
   c. We then use a smoothing function[46] to smooth out the LDC in the first 72 hours.
   d. We convert the hourly LDC created above to Trading Intervals by assuming that the MW demand in any given half-hourly Trading Interval is the same as the associated hour, i.e. if the demand was 4000 MW for 8:00 A.M on 1/10/2021 it would be also be 4000 MW for 8:30 A.M.
2. Add the reserve margin, IL allowance and LFAS component of the WEM Rule 4.5.9(a) calculation (as provided by AEMO) on top of the above LDC as required by WEM Rule 4.5.10(e)(ii).

2.6 Phase 5: EDDQ

We forecast the EDDQ using the following approach:

1. First, forecast EUE when DSM is dispatched for zero hours (EUEt,0). This involves repeating the simulation of unserved energy 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 WEM Rule 4.5.14C(a).

[46] We use a quadratic approximation to smooth the LDC.

2. Second, forecast EUE when DSM is dispatched for 200 hours ($EUE_{t,200}$). This involves repeating 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 WEM Rule 4.5.14C(b).
3. Finally, calculate EDDQ in year t as follows:
   a. $EDDQ_t = \frac{EUE_{t,0} - EUE_{t,200}}{Expected\ DSM\ Capacity\ Credits_t}$.

3 Results

3.1 Reliability Assessment

The reliability assessment indicates that for all Capacity Years of the Long Term PASA Study Horizon (2020-21 to 2029-30) the RCT will be set by the forecast peak quantity determined by WEM Rule 4.5.9(a).

Table 5 summarises the results of the reliability assessment. Here we see that the peak forecast component is sufficient to limit expected energy shortfalls to 0.002% of annual energy consumption in all Capacity Years. Furthermore, the absolute value of EUE is well short of the reliability threshold specified in WEM Rule 4.5.9(a). The EUE estimates from the previous year's modelling are included for comparison.

Table 5: Results of reliability assessment

Capacity Year	RCT (MW)[47]	50% POE peak forecast (MW)	Expected Annual energy consumption (MWh)	0.002% of Expected annual energy consumption (MWh)	EUE (MWh)	EUE as % of expected annual energy consumption	EUE – 2019 ESOO (MWh)
2020-21	4,427	3,774	17,935,419	358.71	0.00	0.0000000%	0.16
2021-22	4,437	3,782	17,539,137	350.78	0.00	0.0000000%	0.02
2022-23	4,421	3,758	17,253,793	345.08	0.00	0.0000000%	0.64
2023-24	4,332	3,707	16,986,658	339.73	0.15	0.0000009%	0.43
2024-25	4,342	3,684	16,828,732	336.57	2.22	0.0000132%	0.14
2025-26	4,383	3,727	16,746,365	334.93	0.00	0.0000000%	0.22
2026-27	4,361	3,719	16,743,152	334.86	0.00	0.0000000%	0.02
2027-28	4,378	3,733	16,793,621	335.87	1.06	0.0000063%	0.80
2028-29	4,327	3,683	16,888,850	337.78	1.45	0.0000086%	0.20
2029-30	4,356	3,720	17,033,731	340.67	1.92	0.0000113%	N/A

[47] Set by WEM Rule 4.5.9(a) 10% POE + reserve margin +LFAS requirement + IL Allowance

Total EUE in this year's modelling is higher than the previous year but remains low. EUE in earlier years is comparable to last year, with a noticeable increase from 2024-25 onwards. This is due to two factors:

- The retirements of Muja_G5 and Muja_G6 (from the start of 2022-23 and 2024-25 respectively) lead to a higher proportion of intermittent generation in the remaining generation mix (note that the total capacity remains the same as total capacity is scaled to meet the RCT, see Appendix A.2). This leads to a lower capacity margin (the difference between total available capacity and hourly load) in winter periods (where most intermittent generation is unavailable) and increases the likelihood of unserved energy in those months, especially in later years with higher loads in winter (see Appendix A.4.5).
- The forced outage rates (FORs) for many large thermal units are higher than in the previous year. This means that a higher proportion of generation may be on outage when the capacity margin) is low, increasing the likelihood of unserved energy.

Table 6 shows EUE across the modelling horizon, by hour and month. We note that unserved energy (while still common in January and February) is most likely to occur in June, when a low amount of intermittent generation is available (note also that the periods with EUE in June have few or no planned outages).

Table 6: Total EUE by month/hour

Month/Hour	14:00	15:00	16:00	17:00	18:00	19:00
January	0.05	0.00	0.00	0.00	0.00	0.00
February	0.00	0.00	0.09	0.61	0.32	0.14
March	0.00	0.00	0.00	0.15	0.00	0.00
April	0.00	0.00	0.00	0.00	0.00	0.00
May	0.00	0.00	0.00	0.00	0.00	0.00
June	0.00	0.00	0.00	0.73	2.92	0.15
July	0.00	0.00	0.00	0.00	0.42	0.00
August	0.00	0.00	0.00	0.00	0.94	0.00
September	0.00	0.00	0.00	0.00	0.29	0.00
October	0.00	0.00	0.00	0.00	0.00	0.00
November	0.00	0.00	0.00	0.00	0.00	0.00
December	0.00	0.00	0.00	0.00	0.00	0.00

3.2 Availability Class Requirements

The Availability Class requirements for Capacity Years 2021-22 and 2022-23 are summarised in Table 7 below, Table 8 compares the Availability Class Requirements derived in the 2019 LT PASA to the current results:

Table 7: Availability Curve, 2021-22 and 2022-23

	2021-22	2022-23
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1		
Minimum capacity	3,557	3,371
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2		
DSM	880	1050

Table 8: Comparing 2020 Availability Curve to 2019 Availability Curve (2019 results in parentheses)

2021-2022	
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1	
Minimum capacity	3,557 (3,657)
RCT	
RCT	4,437 (4,482)
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2	
DSM	880 (825)

The capacity associated with Availability Class 2 has increased by 55 MW from the previous year. For the 2022-23 Capacity Year, we see a significant increase in allowable DSM to 1050 MW. The increase in allowable DSM capacity across both years reflects the impact of increasing behind the meter PV on load shapes.

In particular, as the capacity of BTM PV increases, we see both lower minimum demand values and lower operational loads during the shoulder season (where PV generates but underlying loads are generally low). Typically, the shoulder season is where most of the EUE in the Availability Classes modelling occur, as this is where most planned outages are scheduled to occur and the limitations of DSM availability (200 hours, deployed to minimise the peak and not the capacity margin) mean that DSM will typically be unavailable for the shoulder season. As the operational loads in these periods have decreased, the capacity margin in the shoulder season is higher. This means that more DSM is allowable before these periods start to produce unserved energy.

Continued growth in the uptake of BTM PV further reduces the operational consumption in the shoulder season for the 2022-23 Capacity Year compared to the 2021-22 Capacity Year. This further increases the capacity margin in the shoulder season, leading to an additional increase in the allowable DSM capacity for the 2022-23 Capacity Year.

3.3 Availability Curves

The Availability Curves are illustrated in Figure 5 and Figure 6:

Figure 5: 2021-22 Capacity Year Availability Curve

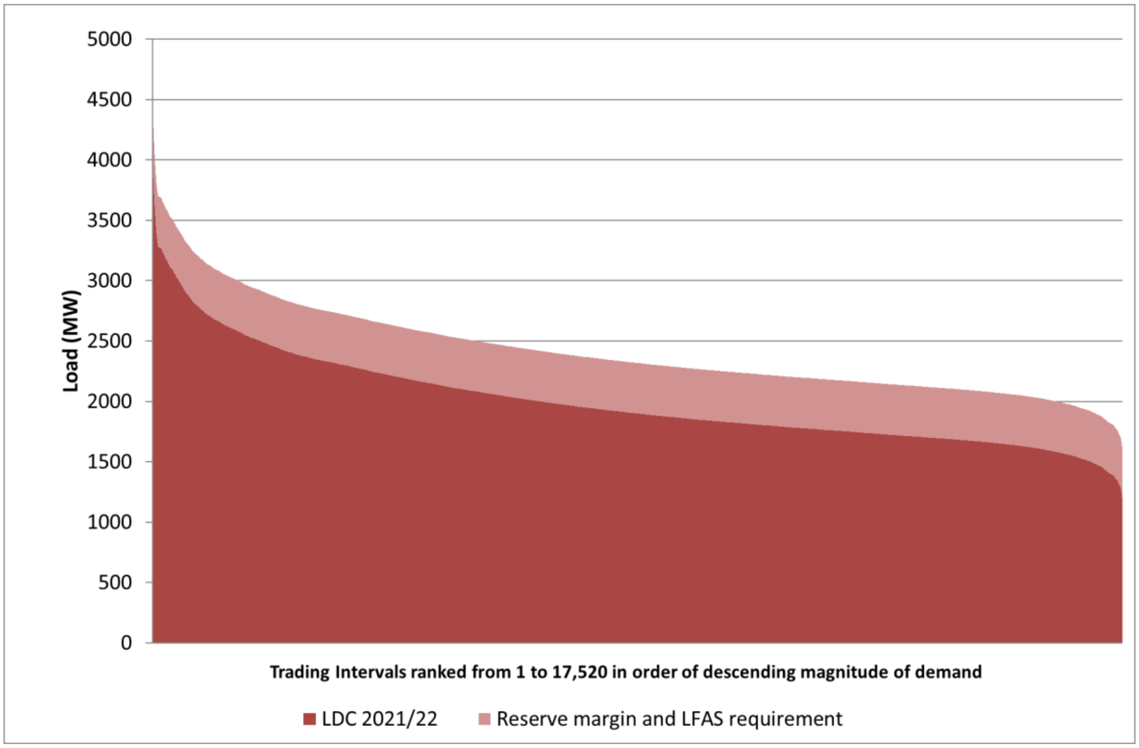
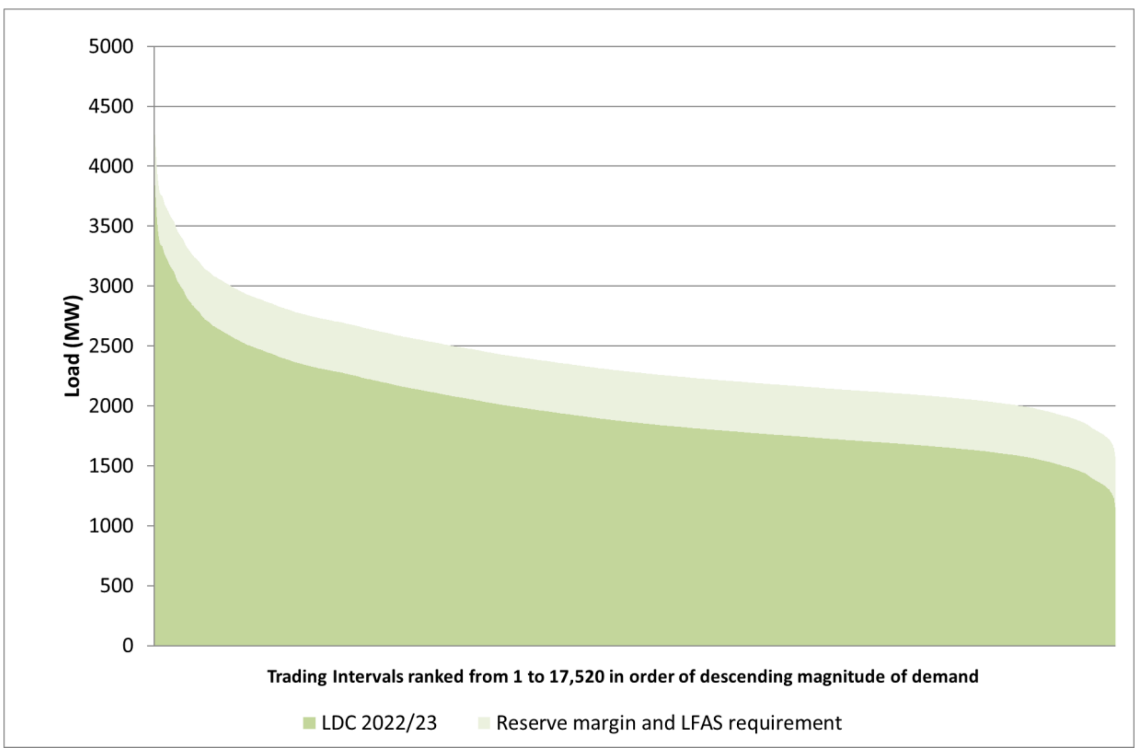


Figure 6: 2022-23 Capacity Year Availability Curve



3.4 EDDQ

The EDDQ results are summarised in Table 9. This also provides the resulting DSM Reserve Capacity Price (RCP) assuming an interim DSM Activation Price of $33,460[48].

Table 9: EDDQ results

Capacity Year	EUE (t,0)	EUE (t,200)	DSM Capacity Credits (t)	EDDQ (t)	DSM RCP ($/MW)	DSM RCP (2019) ($/MW)
2020-21	0.000	0.000	66	0.000	$16,730.00	$16,820.85
2021-22	0.000	0.000	84.5	0.000	$16,730.00	$16,842.34
2022-23	0.060	0.000	86	0.001	$16,753.53	$16,942.12
2023-24	0.662	0.161	86	0.006	$16,924.99	$16,964.42
2024-25	5.136	2.444	86	0.031	$17,777.33	$16,846.40
2025-26	0.312	0.000	86	0.004	$16,851.49	$16,930.76
2026-27	1.290	0.149	86	0.013	$17,173.69	$16,755.15
2027-28	4.179	1.068	86	0.036	$17,940.42	$17,363.10
2028-29	5.364	1.508	86	0.045	$18,230.26	$16,822.07
2029-30	8.143	2.089	86	0.070	$19,085.14	N/A

In comparison to last year's modelling, we note a moderate increase in the EDDQ and consequent DSM from 2024-25 onwards. As noted in Section 3.3, increasing BTM PV generation reduces the load values in off-peak periods. This means that the value of DSM in preventing unserved energy is increased, as more unserved energy occurs within the 200 hours of DSM availability.

[48] As specified in Market Rule 4.5.14F; the DSM Activation Price represents the Value of Lost Load (VoLL).

APPENDIX A MODELLING ASSUMPTIONS

A.1. CAPACITY CREDITS

AEMO has provided us with information on Capacity Credits by Facility.

As noted in Section 2.3, for each year of the LT PASA Study Horizon, we assume Reserve Capacity (generating capacity and DSM) equals the 10% POE operational forecast peak quantity plus reserve margin, IL allowance and the quantity determined by WEM Rule 4.5.9(a). To do this we pro-rate the Capacity Credits (provided by the AEMO and Market Participants) for each Facility so that the total number of Capacity Credits in a given year sum to the forecast peak component given by WEM Rule 4.5.9(a) for that year as follows:

$$\widehat{CC_i} = CC_i \times \frac{10\%\ POE\ peak + Reserve\ Margin + LFAS + IL\ allowance}{\sum_{j \in all\ facilities} CC_j}$$

For scheduled generators CC_i denotes the Capacity Credits the Facility is applying for. For non-scheduled (intermittent) generators, CC_i denotes the average annual Facility generation (based on historic or Market Participant provided generation data). We do not use the Relevant Level value for CC_i as this would underestimate the total available annual generation from an intermittent Facility (noting that the Relevant Level is a measure of intermittent generator performance in intervals with the highest Existing Facility Load for Scheduled Generation (EFLSG)).

A.2. RETIREMENTS AND NEW ENTRY

For new entrant generators that have a commencement date before the beginning of the first Capacity Year for which they have been assigned Capacity Credits, we have modelled the plant commencing when its capacity obligations begin.

There are two retirements during the LT PASA horizon:

- Muja_G5 retires on 01 October 2022
- Muja_G6 retires on 01 October 2024

For these retirements we zero out the capacity on the dates specified. However, we pro-rate the capacity of remaining units so that the total capacity still equals the RCT. This means that although the total level of capacity remains unchanged, the generation mix is different. In particular, a proportion of scheduled generation retires, and intermittent generation makes up a larger proportion of the remaining generation.

A.3. OUTAGES

A.3.1. Planned Outages

Planned outage assumptions have been developed using the methodology described in Section 2.3.4. In general, planned outages proceed in the modelling as provided, but we have moved two planned outages that violated our planning margin in one period (moving both a day later).

A.3.2. Forced Outages

Forced outage assumptions have been developed by analysing the 36-month historical FOR (from the most recent 36 months). We have used a 36 month average FOR to align with WEM Rule 4.11.1(h) and WEM Rule 4.11.1D, which may affect a Facility's Capacity Credit assignment if their 36 month average forced outage rate exceeds certain thresholds.

We have assumed a FOR of 0.1% for Facilities with a zero historic FOR (mainly intermittent Facilities). Assuming a FOR of 0% for these Facilities will be unrealistic as equipment is unlikely to have a zero failure rate over the ten-year modelling horizon.

We have also included a Mean Time to Repair (MTR) value which denotes the amount of time a plant will be offline following a forced outage event. This value is derived by classifying plants into short (12 hours), medium (24 hours), and long (144 hours) duration outage plants, based off their historical downtimes. For new plants we have assumed FOR and mean times to repair will be similar to current plants of a similar technology.

The majority of FOR assumptions remain similar to last year. However, there are multiple thermal generators which have seen large increases in their FORs.

A.4. DEMAND

In this section, we set out:

- The RCT and demand forecasts
- How we scale the underlying value occurring at the operational peak (provided by AEMO) to reflect the 50% POE underlying peak (See Section 2.2.2)

- The underlying reference year load shapes which are used as a basis to forecast underlying load shape and hourly load over the Long Term PASA Study Horizon
- The forecasted load shapes
- The seasonal distribution of peak periods by Capacity Year

A.4.1. RCT and Demand forecasts

The peak demand and energy consumption forecasts applied in the load forecasts include:

- The peak forecast component of clause 4.5.9(a) of the WEM Rules (which has set the RCT in every Capacity Year of the Long Term PASA Study Horizon)
- The underlying demand value occurring at the 50% POE operational peak (provided by AEMO)
- The underlying 50% POE peak, scaled from historical data and used in the modelling
- The 50% and 10% POE operational peak demand forecasts
- The annual underlying and operational energy consumption forecast under the expected demand growth scenario

A.4.2. Scaling the Underlying Load Occurring at the Operational Peak Time to the Underlying Peak

As noted in Section 2.2.2, the forecast underlying value provided by AEMO do not reflect the underlying peak demand but instead reflect the underlying demand value occurring at the time of operational peak demand in each forecast year. This means we must scale up the underlying values provided by AEMO to reflect the actual underlying peak value.

Our scaling process is as follows[49]:

1. Using the historical load curves in Section 2.2.1, for each of the five full historical Capacity Years (2014-15 to 2018-19), we identify the operational peak day.
2. For this day, we find the daily underlying peak demand.
3. For each hour in this day we convert the associated underlying load into percentage of daily underlying peak demand. For a given hour, this tells us how much lower (in percentage terms) an hour's underlying demand was than the peak.

[49] Note that this process assumes that for all forecast Capacity Years the underlying peak occurs on the same day as the operational peak.

4. We then take the average of this calculation across the five Capacity Years; this gives us an average underlying profile.
5. Using the time of forecast peak information provided by AEMO, we convert the underlying demand provided by AEMO into the underlying peak by scaling the underlying demand values up by the profile for the relevant hour.

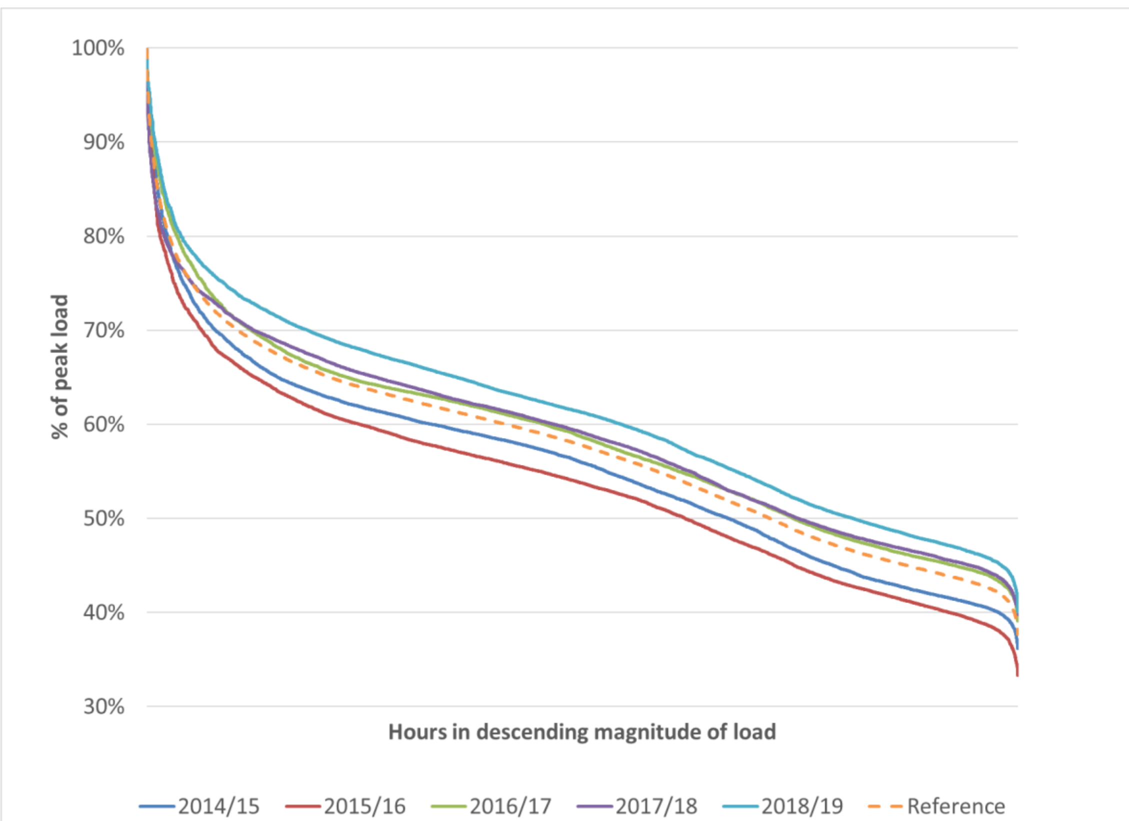
A.4.3. Reference Underlying Load Shape

We have developed the reference underlying profile using the Total Sent Out Generation dataset from AEMO to calculate historical hourly load. Additionally:

- Curtailments (due to generation shortfall) are also added on to get gross load.
- Historical BTM PV generation is added to the hourly load

This gives hourly historical underlying demand over the last five full Capacity Years (2014-15 to 2018-19). We then construct load shapes for each Capacity Year. Averaging across the load shapes for each of these Capacity Years gives the reference load shape in Figure 7 below:

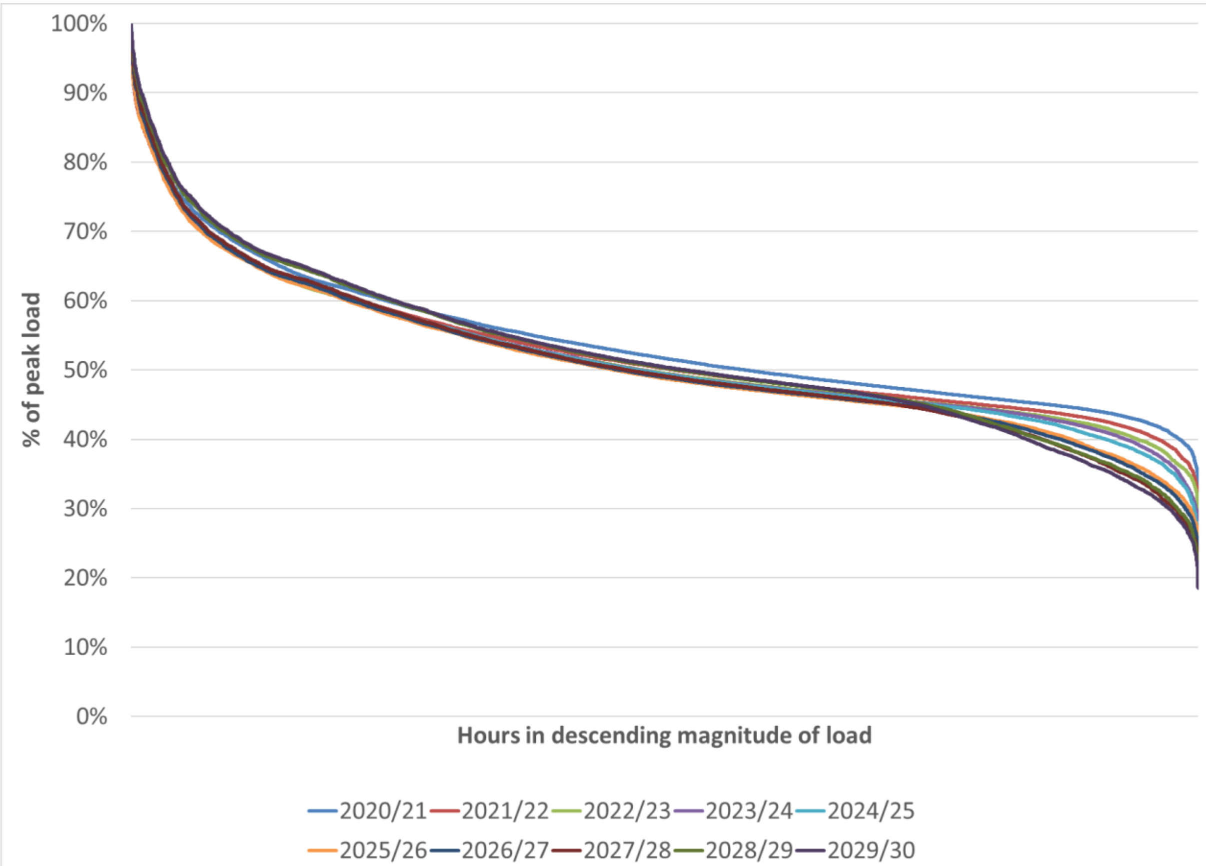
Figure 7: Underlying reference load shape



A.4.4. Forecasted Load Shape

Figure 8 shows the load shape of the forecasted operational load profiles over the modelling horizon:

Figure 8: Forecasted LDC's over the modelling horizon



A.4.5. Seasonal Distribution of Forecasted Operational Load Peak Periods

Table 10 summarises the top 50 peak periods by season by Capacity Year:

Table 10: Seasonal distribution of top 50 peak periods by Capacity Year

Capacity Year/Season	Summer	Autumn	Winter	Spring
2020-21	76.00%	12.00%	12.00%	0.00%
2021-22	72.00%	12.00%	16.00%	0.00%
2022-23	68.00%	14.00%	18.00%	0.00%
2023-24	68.00%	8.00%	24.00%	0.00%
2024-25	64.00%	8.00%	28.00%	0.00%
2025-26	60.00%	10.00%	30.00%	0.00%
2026-27	56.00%	12.00%	32.00%	0.00%
2027-28	58.00%	8.00%	34.00%	0.00%
2028-29	56.00%	8.00%	36.00%	0.00%
2029-30	46.00%	10.00%	44.00%	0.00%

A.5. Planning Margin

For the Availability Class requirements modelling (Section 2.4) and the planned outage scheduling (Section 2.3.4), we model a planning margin representing the Ancillary Services and Ready Reserve Standard contemplated under WEM Rule 3.18.11. This planning margin is calculated as the capacity of the largest current generator and 70% of the capacity of the second-largest generator, minus any interruptible loads.

The unscaled planning margin is for a given year is calculated as:

$$PM = CC_{i \in largestunit} + \left(0.7 \times CC_{i \in 2ndlargestunit}\right) + \sum_{i \in IL} CC_i$$

The current largest and second largest generators by Capacity Credits are NEWGEN_NEERABUP_GT1 and NEWGEN_KWINANA_CCG1 with a capacity of 330.6 MW and 327.8 MW respectively. Interruptible loads currently have a MW capacity of 42MW.

This gives us the following:

$$PM = 330.6 + (0.7 \times\ 327.8) - 42 = 518$$

Therefore, we have assumed a planning margin of 518 MW for the Planned Outage scheduling.

For the minimum generation capacity calculation under clause 4.5.12(b), it is necessary to scale the planning margin based on the ratio of the RCT to total Capacity Credits for a given year. This is because the capacity of the largest unit and the second largest unit for each modelling year will be based on the pro-rated capacity as follows:

$$\widehat{CC}_i = CC_i \times \frac{10\%\ POE\ peak + Reserve\ Margin + LFAS}{\sum_{j \in all\ facilities} CC_j}$$

The use of an unscaled planning margin, with *scaled* capacity, overestimates the contingency implied by the planning margin. It is therefore more appropriate to use a planning margin with the generator's capacity scaled by the RCT for each year t:

$$Planning\ Margin_t = \widehat{CC}_{t,i \in largestunit} + \left(0.7 \times \widehat{CC}_{t,i \in 2ndlargestunit}\right) + \sum_{i \in IL} \widehat{CC}_{ti}$$

Table 11 summarises the scaled planning margin assumptions for the minimum generation capacity modelling:

Table 11: Scaled Planning Margin assumptions for WEM Rule 4.5.12(b)

Capacity Year	Unscaled Planning Margin	Scaling Factor	Scaled Planning Margin
2021-22	518	0.843	436.628
2022-23	518	0.856	443.200

GLOSSARY

Table 12 presents a glossary of the terms used in this report:

Table 12: Glossary

Term	Definition
Behind-the-meter (BTM)	PV and battery storage systems that produce energy and are connected at a customer's premises. In the WEM ESOO, behind-the-meter PV capacity includes both residential and commercial rooftop PV that is less than 100 kilowatts (kW) and commercial PV systems ranging between 100 kW and 10 MW
Capacity Credit	A notional unit of Reserve Capacity provided by a Facility during a Capacity Year, where each Capacity Credit is equal to 1 MW of capacity
Capacity margin	The difference in any period between hourly load and total available capacity
Capacity Year	A Capacity Year commences in the Trading Interval starting at 8:00 AM on 1 October and ends in the Trading Interval ending at 8:00 AM on 1 October of the following calendar year.
Demand Side Management (DSM)	A type of capacity that can reduce its consumption of electricity from the SWIS in response to a dispatch instruction. Usually made up of several customer loads aggregated into one Facility.
Demand side programme (DSP)	A Facility registered in accordance with clause 2.29.5A of the WEM Rules.

Term	Definition
Intermittent generator	A generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g. wind speed).
Long Term Projected Assessment of System Adequacy (LTPASA)	A study conducted in accordance with clause 4.5 of the WEM Rules to determine the Reserve Capacity Target for each year in the Long Term PASA Study Horizon and prepare the WEM ESOO.
Long Term PASA Study Horizon	The 10 year period commencing on 1 October of Year 1 of a Reserve Capacity Cycle.
Load chronology	The chronology of a year (periods), ranked by magnitude of load (i.e. 1 is the peak period), sorted into chronological order.
Load shape	Hourly load data for a year (expressed in percentage of peak demand), in descending order of magnitude.
Operational demand	Demand (in MW) that is met by all grid-connected generation, excluding demand met by behind-the-meter PV generation
Probability of exceedance (POE)	The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded on average once in every 10 years.
Reserve Capacity Cycle	A four-year period covering the cycle of events described in clause 4.1 of the WEM Rules.
Reserve Capacity Price (RCP)	The price for capacity paid to Capacity Credit holders and determined in accordance with clause 4.29.1 of the WEM Rules.

Term	Definition
Reserve Capacity Target (RCT)	AEMO's estimate of the total quantity of generation or DSM capacity required in the SWIS to satisfy the Planning Criterion
Underlying demand	Operational demand (in MW) plus an estimation of behind-the-meter PV generation.