ROBINSON BOWMAKER PAUL

AUSTRALIAN ENERGY MARKET OPERATOR

Modelling Report - 2021 Assessment of System Reliability for the South West Interconnected System

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Executive Summary

Australian Energy Market Operator (AEMO) has engaged Robinson Bowmaker Paul (RBP) to undertake the 2021 Assessment of System Reliability for the South West Interconnected System (SWIS) (referred to as the 2021 Reliability Assessment for short). This report contains our modelling methodology, assumptions, and results.

Context

AEMO is responsible for operating a Reserve Capacity Mechanism to ensure that adequate supply is available over the long term in the SWIS. To assess the amount of Reserve Capacity that is required, AEMO undertakes a Long-term Projected Assessment of System Adequacy (Long Term PASA) as required under clause 4.5 of the Wholesale Electricity Market Rules (WEM Rule 4.5). The results of the Long Term PASA feed into the AEMO's WEM Electricity Statement of Opportunities (ESOO) report which forecasts:

- The Reserve Capacity Target (RCT) for each year in the Long Term PASA Study Horizon (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 plus a reserve margin (WEM Rule 4.5.9(a)).
  - A reliability component to ensure expected energy shortfalls are limited to 0.002% of annual demand (WEM Rule 4.5.9(b)).
- Availability Class[1] requirements which are defined by WEM Rule 4.5.12.
- The Availability Curves to determine the minimum capacity requirement for each Trading Interval in the Capacity Year, which is defined by WEM Rule 4.5.10(e).

[1] There are two Availability Classes defined in the WEM rules. Availability Class 1 is all energy producing capacity and any other capacity that is expected to be dispatched for all Trading Intervals in a Capacity year, while Availability Class 2 refers to Certified Reserve Capacity which is not expected to be available to be dispatched for all Trading Intervals in a Capacity Year.

The Reliability Assessment is a key component of the Long Term PASA analysis. The purpose of our modelling is to:

- Undertake an Expected Unserved Energy (EUE) 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 (AC1) capacity and the maximum allowable capacity associated with Availability Class 2 (AC2).
- Develop the Availability Curve defined by WEM Rule 4.5.10(e).

Scope of Modelling

Our modelling covers:

- The EUE assessment for the 2021 Long Term PASA Study Horizon covering Capacity Years 2021-22 to 2030-31.
- The Availability Curve for each of the second and third Capacity Years of the 2021 Long Term PASA Study Horizon (2022-2023 and 2023-24 Capacity Years).
- The Availability Classes for each of the second and third Capacity Years of the 2021 Long Term PASA Study Horizon (2022-2023 and 2023-24 Capacity Years).

Methodology

Our modelling approach has four phases:

- **Phase 1: Hourly Load Forecasting.** Forecasting five hourly operational[2] load traces over the Long Term PASA study horizon, taking into account the annual 50% Probability of Exceedance (POE) summer peak forecast, expected annual energy consumption forecasts and hourly distributed energy resources (DER)[3] contribution.

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[2] AEMO distinguishes between operational demand and underlying demand. Operational demand refers to network demand met by utility-scale generation and excludes demand met by behind-the-meter photovoltaics (PV) generation. Underlying demand refers to operational demand plus an estimation of behind-the-meter PV generation and the impacts of battery storage.

[3] Note that for this report our definition of DER includes behind-the-meter PV and battery storage, but not electric vehicles.

- **Phase 2: EUE Assessment.** Simulating EUE over the Long Term 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 enables AEMO to determine the RCT for each Capacity Year in the Long Term 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].
- **Phase 4: Availability Curves.** Developing the two-dimensional duration curves required under WEM Rule 4.5.10(e).

This year we have made changes to our modelling methodology in three areas:

- **Network constraints:** This year we have modelled both the network constraints for Constrained Access Facilities (partially constrained network access) in the 2021-22 Capacity Year and fully constrained network access thereafter, as fully constrained network access related rule changes are expected to commence on 1 October 2022. The increased complexity of the full constraints requires modifications to our methodology. More details for this new methodology and the rationale behind the changes are given in Section 2.4.2.
- **Intermittent generation and load forecasts:** As the share of intermittent generation grows in the SWIS, the variation or uncertainty in output of such facilities may have a more material impact on unserved energy than previously. To ensure we capture the impacts of intermittency on reliability, we have developed five sets of intra-day profiles for each intermittent generator, with each set of profiles reflecting the average intra-day generation for each month from one of five historical Capacity Years (2015-16 to 2019-20). Hourly load forecasts are also based on the DER profiles and underlying load shape of these historical Capacity Years. The load forecast and intermittent profiles based on a given historical Capacity Year are referred to as a reference year in the remainder of this report (i.e. the load forecast and intermittent profiles based on the 2015-16 Capacity Year are referred to as the 2015-16 reference year). Our model is run five times (once for each

[4] The capacity associated with AC1.

[5] The capacity associated with AC2.

reference year) and EUE is averaged across all five reference years, see Section 2.3 and Section 2.4.4.

- Electric Storage Resources (ESRs): We have extended our modelling methodologies to account for ESRs. We have updated our modelling methodology to reflect the expected availability requirements of ESRs (see Section 2.4.3). As stand-alone ESRs are considered AC2 capacity, our Availability Class requirement modelling methodology has been updated to reflect this (see Section 2.5.1).

Phase 1: Hourly load forecasting

Our approach to hourly load forecasting has five steps:

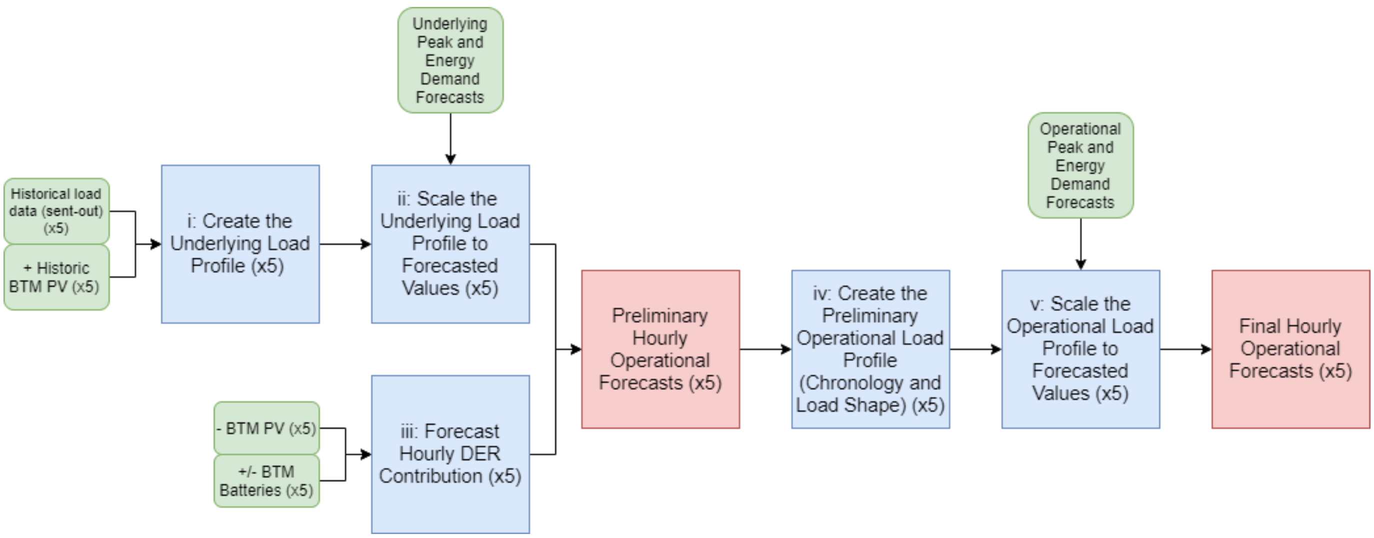
1. Create the underlying load profile: The underlying load shape is developed using historical sent out generation data (adding historical behind-the-meter PV generation to get underlying load) to derive a load shape and chronology for each reference year.
2. Scale the underlying load profile to forecasted values: Hourly underlying load forecasts for each year in the Long Term PASA Study Horizon are developed by scaling up the underlying load profile for each reference year to match the underlying 50% POE peak and expected underlying annual consumption forecasts for the respective Capacity Year.
3. Forecast hourly DER contribution: Using DER data provided by AEMO, we forecast five series (based on each reference year's behind-the-meter PV and battery capacity factors) of hourly behind-the-meter PV generation and behind-the-meter battery charge/discharge over the modelling horizon.
4. Create the preliminary operational load profiles (chronology and load shape): The hourly underlying load forecasts and hourly DER contribution forecasts for each reference year are combined and adjusted for network losses to create five hourly operational load forecasts. These are processed into an operational load profile for each Capacity Year in each of the five reference years by:
    a. 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)
    b. Indexing the load shape by its associated date in the hourly forecasts to create a load chronology.

5. 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 scale the five preliminary operational load profiles to forecasted values, producing five 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 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 2.3.1 - 2.3.5), while red boxes refer to outputs.

Figure 1: Overview of the forecasting process



The hourly load forecasts are key inputs into Phases 2, 3 and 4. Specifically:

- They are used as the hourly load across the modelling horizon in the EUE assessment for each reference year, for each Capacity Year in the Long Term PASA Study Horizon.
- They form the basis of the load forecasts used in the Availability Class Requirement modelling. We use an average load profile[6], which is then adjusted to account for AC2 dispatch. This process creates AC2 adjusted hourly load traces which are used in the modelling.

[6] This is based on the average underlying load shape (across the five reference years) applied to the chronology implied by the most recent full Capacity Year (2019-20) and also uses an average DER profile.

- They are also used to derive the two-dimensional duration curve defined in WEM Rule 4.5.10(e), which is developed into the Availability Curves by adjusting further the scaled profiles to incorporate the requirements of WEM Rule 4.5.10(e).

Phase 2: EUE assessment

We have used our bespoke model, CAPSIM[7] to conduct the EUE assessment. CAPSIM simulates the capacity gap (a simple arithmetic calculation subtracting load from available energy producing and DSM capacity) for every hour[8] of every year, sequentially, given a specific generation mix, load profile, planned outage schedule and random forced outages. This assessment is conducted for the five reference years, with intermittent profiles and load forecasts varying by reference year. Both CAF constraints (in the 2021-22 Capacity Year) and fully constrained network access (from the 2022-23 Capacity Year onwards) are modelled.

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 (energy producing[9] and DSM capacity) 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 each of the five reference years, using the associated hourly load forecast, intermittent generation profile, randomised forced outages; and using assumptions (common to all reference years) around Electric Storage Resource availability and Planned Outages, 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=50 iterations and R=5 reference years above to estimate EUE for each modelled year as follows:

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

[8] 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.

[9] Includes generation and ESR capacity.

$$\text{EUE(y)} = \frac{1}{R}\frac{1}{N}\sum_{r=1}^{R}\sum_{n=1}^{N}\sum_{h=1}^{H}\text{Unserved Energy (r, n, h)}$$

- EUE(y) is the EUE in year y, where y is one of ten Capacity Years in the Long Term PASA horizon
- Unserved Energy(r,n,h) is the unserved energy in hour h of Capacity Year y as simulated under iteration n of Reference Year r.

4. We then divide EUE(y) by forecast annual energy consumption in year y to express EUE as a percentage.
5. If the percentage in Step 4 is less than or equal to 0.002% then we stop; the RCT is 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 is run over 50 forced outage iterations for each reference year (250 iterations in total) to generate a probability distribution of unserved energy and to estimate EUE for each year of the modelling horizon.

Phase 3: Availability Class requirements

Having determined the RCTs for each year, the next phase 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. Anticipated entry of the ESR capacity as AC2 capacity over the outlook period has led to consequential changes to our methodology for modelling the dispatch of AC2 capacity.

We calculated the minimum generation requirement (AC1 capacity) by simulating unserved energy (for the second and third years of the Long Term PASA Study Horizon) as for the EUE assessment with five differences:

1. First, an average load forecast is created using the average underlying load shape[10] and the average historical hour-of-the-yearly behind-the-meter PV and battery capacity

[10] Applied to the chronology implied by the most recent full Capacity Year (2019-20)

factors. Note also that the average intermittent generational profiles (for each facility) across the five reference years are used in the modelling to align with this forecast.

2. Second, AC2 capacity is modelled in greater detail to take into account the constraints around the availability of DSM providers[11] and ESR capacity. In short, a given level of AC2 capacity is allocated between ESR and non-Interruptible Load DSM capacity according to the ratio of the expected capacity between the two in that Capacity Year. ESR is dispatched for the period from 4:00 P.M. to 8:00 P.M. each day[12] and we then allocate DSM throughout the year using an optimisation model that dispatches DSM to minimise the peak (net of ESR) subject to scheduling and availability constraints.

3. Third, we specify a planning margin in the market model that represents the Ancillary Services requirement and Ready Reserve Standard contemplated in WEM Rule 3.18.11. We model a planning margin that varies based on the scaled[13] Capacity Credits of the two largest units.

4. Fourth, 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.

5. Finally, for each year of the relevant Reserve Capacity Cycle, we iterate the model to reallocate the amount of AC2 and AC1 (reducing the AC1 capacity as AC2 capacity

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

[12] ESR capacity is required to be available for the Electric Storage Resource Obligation Intervals (ESROI). The ESROIs have not been determined by AEMO for the 2023-24 Capacity Year. For reliability assessment purposes, we assume these occur from 4:00 P.M. to 8:00 P.M. each Trading Day, as this period generally coincide with peak operational demand.

[13] We use a scaled planning margin as the capacity of the largest unit and the second largest unit are 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.

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 energy producing capacity at which the EUE equals 0.002% of expected demand then sets the minimum energy producing capacity.

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.

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 first 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 is done using the average operational load profile developed for the Availability Class Requirement modelling, by scaling this profile up to the 10% POE operational peak forecasts provided by AEMO using the same process described in Section 2.3.5.

    b. We then estimate the forecast load for the remaining hours (25-8,760 hours) assuming a 50% POE peak forecast under the expected demand growth scenario (i.e. the load forecasts created for the Availability Class Requirement)

    c. We then use a smoothing function[14] to smooth out the LDC in the first 72 hours.

    d. We then convert the hourly LDC to Trading Intervals (as required by WEM Rule 4.5.10(e)) 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 also be 4000 MW for 8:30 A.M.

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

2. We add the reserve margin, Intermittent Load (IL) allowance and LFAS component of the WEM Rule 4.5.9(a) calculation (as provided by AEMO) on top of the LDC as required by WEM Rule 4.5.10(e)(ii).

Results

EUE Assessment

The EUE assessment indicates that for all Capacity Years of the Long Term PASA Study Horizon (Capacity Years 2021-22 to 2030-31), 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 EUE 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 1: Results of EUE assessment

Capacity Year	RCT (MW) [a]	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 – 2020 ESOO (MWh)
2021-22	4,356	3,686	17,127,210	342.54	3.86	0.0000225%	0.00
2022-23	4,380	3,708	17,018,680	340.37	3.61	0.0000212%	0.00
2023-24	4,396	3,733	16,841,560	336.83	0.87	0.0000051%	0.15
2024-25	4,409	3,736	16,666,840	333.34	7.97	0.0000478%	2.22
2025-26	4,410	3,739	16,521,750	330.44	1.89	0.0000114%	0.00
2026-27	4,427	3,755	16,395,180	327.90	9.45	0.0000576%	0.00
2027-28	4,432	3,750	16,263,580	325.27	3.65	0.0000224%	1.06
2028-29	4,441	3,767	16,160,460	323.21	9.06	0.0000560%	1.45
2029-30	4,444	3,769	16,050,720	321.01	39.12	0.0002437%	1.92
2030-31	4,443	3,772	15,986,800	319.74	4.57	0.0000286%	N/A

a. Set by WEM Rule 4.5.9(a) 10% POE under the expected demand growth scenario + reserve margin +LFAS requirement + IL Allowance

EUE in this year's EUE assessment is higher across all Capacity Years than in the 2020 Reliability Assessment but remains well under the 0.002% limit. Unserved energy is higher in this year's EUE assessment due to the following:

- **The impact of modelling five reference years**: There are two reference years (2016-17 and 2018-19) with particularly high winter loads, which due to low intermittent generation over winter, decreases capacity margins and significantly increases the risk of unserved energy (UE)[15]. These two reference years are driving the majority of the UE and represent more extreme conditions (in the sense of having higher winter loads and lower intermittent generation over winter periods at risk of UE) than the approach used in the 2020 Reliability Assessment where we used a five-year average load profile and average intermittent profiles. Because of the small amount of unserved energy in the EUE

[15] We note that the 2017-18 reference year also has a large proportion of winter periods in its top 50 peak periods, but unlike the 2016-17 and 2018-19 reference years the majority of the 2017-18 reference year's winter peak periods occur in August which has generally higher intermittent generation in the evening than June or July.

assessment, a non-zero level of unserved energy in any given reference year will significantly increase our estimate of EUE in relative terms.

- **Constraints (and new entry driving congestion):** As noted above, in the 2021-2022 Capacity Year we only model the network constraints for Constrained Access Facilities (partially constrained network access) but from the 2022-23 Capacity Year onwards we model fully constrained network access. The maximum partially constraint curtailment in periods with unserved energy in 2021-22 is 86 MW whereas the maximum full constraint curtailment in periods with unserved energy is 312 MW, which is a substantial increase. This is partly due the full constraints themselves but is mainly driven by the entrance of several new generators in congested areas of the network. As total capacity is scaled down to equal the RCT, the entrance of a new Facility which is constrained down frequently reduces the modelled capacity of Facilities which are not constrained down frequently[16]. Where a constraint binds and reduces generation in periods at risk of UE, this can increase the risk of UE or increase the magnitude of UE where UE already exists.

[16] As a simplified example, consider a hypothetical Capacity Year with a RCT of 4,000 MW and total unscaled capacity of 4,000 MW, assume capacity of Facilities in non-congested areas is 3500 MW while Facilities in congested areas have a capacity of 500 MW. If new capacity of 1,000 MW enters in congested areas, then total capacity equals 5,000 MW and total capacity must be scaled down to the RCT at a scaling factor of 0.8. Applying this scaling factor to the capacity in congested areas gives a scaled capacity of 1,200 MW while in non-congested areas the scaled capacity would be 2,800 MW. This means that there is 700 MW less non-congested generation available when Facilities in congested areas are curtailed.

Availability Class requirements

Table 2: Availability Class requirements (2022-23 and 2023-24)

	2022-23	2023-24
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1	3,730	3,496
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2	650	900

Table 3: Comparing 2021 Availability Class requirements to 2020 (2020 results in parentheses)

2022-2023	
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1	
Minimum capacity	3,730 (3,371)
RCT	
RCT	4,380 (4,421)
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2	
DSM	650 (1,050)

The minimum capacity required to be provided by AC1 has increased by 359 MW for the 2022-23 Capacity Year while the maximum capacity associated with AC2 has decreased by 400 MW. From the 2023-24 Capacity Year, the maximum AC2 capacity increase to 900 MW.

The decrease in maximum AC2 capacity in 2022-23 reflects:

- Lower capacity margins in 2022-23 in general (reflected in higher unserved energy in the EUE assessment in the 2021 EUE assessment compared to 2020).
- Planned outages in the shoulder season (when DSM has been exhausted). In the first week of October 2022 (which for this Capacity Year, is where unserved energy begins to occur as we iterate up AC2 capacity), there is 819.62 MW of (scaled) capacity on Planned

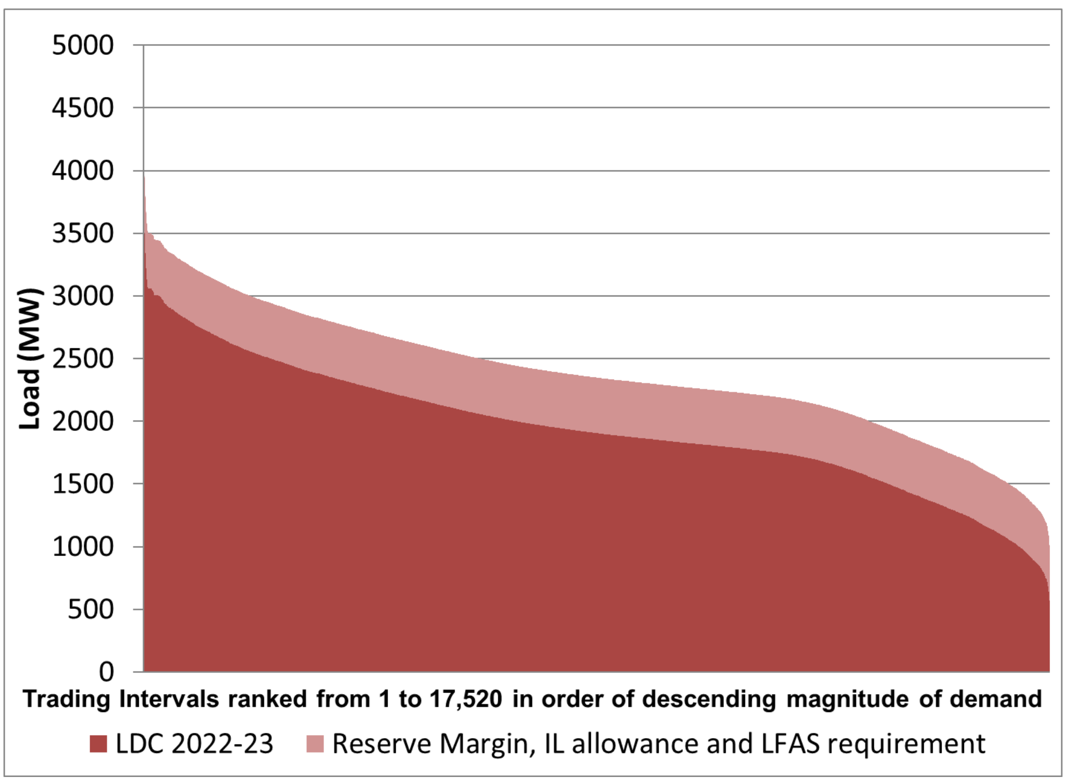
Outage[17], this leads to lower capacity margins for this period and increase the likelihood of unserved energy.

As noted above, our Availability Class requirements modelling methodology has been updated this year to account for stand-alone ESRs for the 2023-24 Capacity Year. Unlike DSM, ESR capacity is not exhausted within 200 hours. This means that ESR capacity is better able to mitigate EUE in the shoulder seasons within the assumed ESROIs (4 P.M. - 8 P.M.). Conversely, where there is a high risk of UE outside of the assumed ESROIs, ESRs are not able to be dispatched in our modelling. In this year's demand forecasts, the great majority of high load periods occur within the assumed ESROI so ESR capacity is able to mitigate UE. This combined with higher overall capacity margins in the 2023-24 Capacity Year compared to the 2022-23 Capacity Year has meant that the maximum AC2 capacity has increased.

Availability Curves

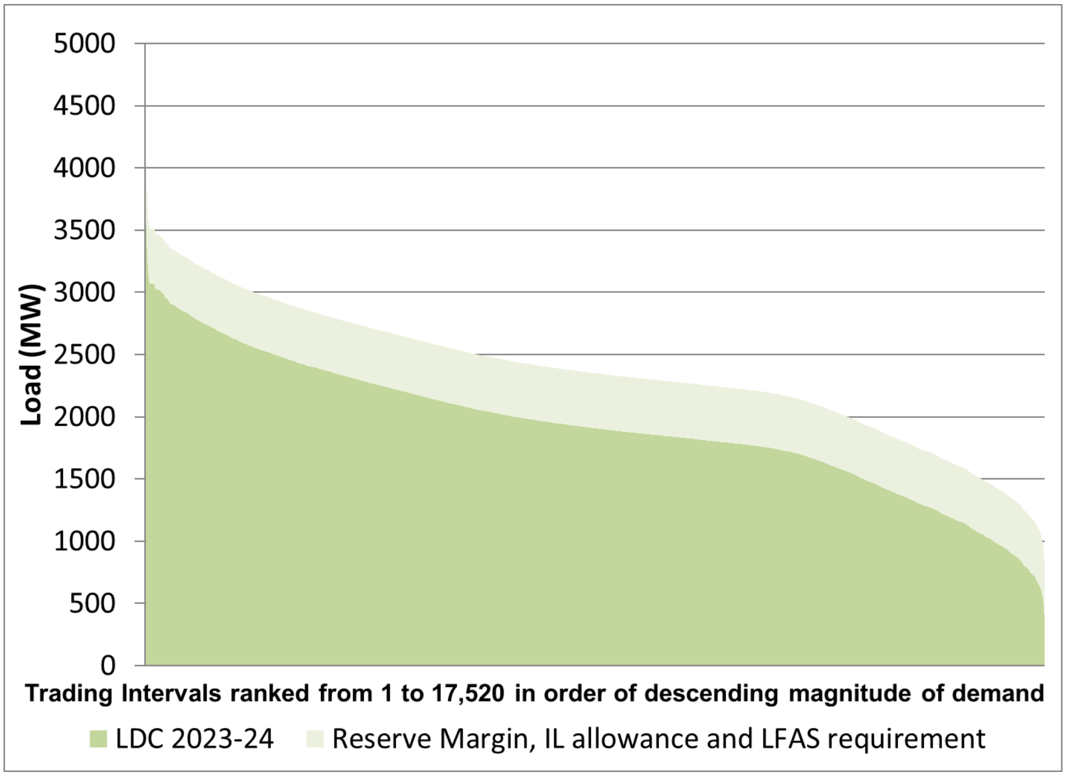
The Availability Curves (WEM Rule 4.5.10(e)) are illustrated in Figure 2 and Figure 3.

Figure 2: Availability Curve (2022-23 Capacity Year)



[17]Based on information provided by market participants under WEM Rule 4.5.3.

Figure 3: Availability Curve (2023-24 Capacity Year)



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1 INTRODUCTION

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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 is required, AEMO undertakes a Long-term Projected Assessment of System Adequacy (Long Term PASA) as required under clause 4.5 of the Wholesale Electricity Market Rules (WEM Rule 4.5). The results of the Long Term PASA feed into the AEMO's WEM Electricity Statement of Opportunities (ESOO) report which forecasts:

- The Reserve Capacity Target (RCT) for each year in the Long Term PASA Study Horizon (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 plus a reserve margin (WEM Rule 4.5.9(a)).
  - A reliability component to ensure expected energy shortfalls are limited to 0.002% of annual demand (WEM Rule 4.5.9(b)).
- Availability Class[18] requirements which are 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).

[18] There are two Availability Classes defined in the WEM rules. Availability Class 1 is all energy producing and any other capacity that is expected to be dispatched for all Trading Intervals in a Capacity year, while Availability Class 2 refers to Certified Reserve Capacity which is not expected to be available to be dispatched for all Trading Intervals in a Capacity Year.

The Reliability Assessment is a key component of the Long Term PASA analysis. The purpose of our modelling is to:

- Undertake an Expected Unserved Energy (EUE) 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 (AC1) capacity and the maximum allowable capacity associated with Availability Class 2 (AC2).
- Develop the Availability Curve defined by WEM Rule 4.5.10(e).

1.2 Scope of modelling

Our modelling covers:

- The EUE assessment for the 2021 Long Term PASA Study Horizon covering Capacity Years 2021-22 to 2030-31.
- The Availability Curve for each of the second and third Capacity Years of the 2021 Long Term PASA Study Horizon (2022-2023 and 2023-24 Capacity Years).
- The Availability Classes for each of the second and third Capacity Years of the 2021 Long Term PASA Study Horizon (2022-2023 and 2023-24 Capacity Years).

1.3 Structure of this report

The remainder of our report is structured as follows:

- Our modelling methodology is described in Chapter 2
- The modelling results are presented in Chapter 3
- Key assumptions underpinning our modelling are summarised in Appendix A

2 MODELLING METHODOLOGY

2.1 INTRODUCTION AND BACKGROUND

RBP has undertaken the Reliability Assessment since 2012. Since 2019, we have used a bespoke model (CAPSIM), which simulates the capacity gap (a simple arithmetic calculation subtracting load from available energy producing[19] and demand side management [DSM] capacity) for every hour of every year given a specific generation mix, load profile, planned outage schedule and random forced outages. This model was developed specifically for the context of the Reliability Assessment and delivers a large amount of statistical power while maintaining the chronological approach necessary to capture the increasing role of intermittent generation (and in the future, Electric Storage Resources [ESRs]) in the WEM.

This year, we have made material changes to our methodology in three areas.

2.1.1 Constraints modelling

The first change is that this year we have modelled both the partially constrained network access (in the 2021-22 Capacity Year) and fully constrained network access thereafter, as fully constrained network access related rule changes are expected to commence on 1 October 2022. The increased complexity of the full constraints requires modifications to our methodology. More details for this new methodology and the rationale behind the changes are given in Section 2.4.2.

2.1.2 Intermittent generation and load forecasts

The second change is in our treatment of intermittent generation. In previous years, we have developed 12 intra-day monthly profiles for each generator (from historical generation in the case of existing generators, or participant estimates of generation over five historical years, in the case of new generators). These profiles were then scaled to reflect the ratio of the RCT to total Capacity Credits for each Capacity Year and formed the basis of the intermittent facilities' available capacity in each modelled year. As the share of intermittent generation grows in the SWIS, the variation or uncertainty in output of such facilities may have a more material impact on unserved energy than previously. To ensure we capture the impacts of intermittency on reliability, we have developed five sets of intra-day profiles for each intermittent generator, with each set of

[19] Includes generation and ESR capacity.

profiles reflecting the average intra-day for each month from one of five historical Capacity Years from 2015-16 to 2019-20.

Hourly load forecasts are also based on the distributed energy resources (DER)[20] profiles and underlying load shape of these historical Capacity Years to preserve the cross-correlations between DER, utility-scale generation and the weather conditions which drive underlying demand. The load forecast and intermittent profiles based on a given historical Capacity Year are referred to as a reference year in the remainder of this report (I.e. the load forecast and intermittent profiles based on the 2015-16 Capacity Year are referred to as the 2015-16 reference year). Our load forecasting process results in an hourly load forecast for each reference year (each with the same sent out peak and annual energy values, but with different load shapes and chronology due to the five DER profiles). Our model is run five times (once for each reference year) with 50 forced outages iterations (resulting in 250 total forced outage iterations), EUE is averaged across all five reference years.

2.1.3 Incorporating Electric Storage Resources

The third change is that this year we have extended our modelling methodologies to account for ESRs. We have updated our modelling methodology to reflect the expected availability requirements of ESRs (see Section 2.4.3). Additionally, as ESRs are considered AC2 capacity, we have accordingly updated our Availability Class requirement modelling methodology (see Section 2.5.1).

The remainder of this chapter is structured as follows:

- In Section 2.2, we provide an overview of the modelling stages that are required to undertake the EUE assessment (WEM Rule 4.5.9(b)), determine the Availability Class requirements (WEM Rules 4.5.12(b) and 4.5.12(c)) and develop the Availability Curve (WEM Rule 4.5.10(e)).
- In Sections 2.3 to 2.6 we describe each modelling stage in further detail.

2.2 OVERVIEW OF MODELLING APPROACH

Our modelling approach has four phases:

[20] This includes behind-the-meter Photovoltaic (PV) and battery storage, but for the purposes of this report (in contrast to AEMO's definition) not electric vehicles (EV).

- **Phase 1: Hourly Load Forecasting.** Forecasting five hourly operational[21] load traces over the Long Term PASA study horizon, taking into account the annual 50% Probability of Exceedance (POE) summer peak forecast, expected annual energy consumption forecasts and hourly distributed energy resources DER[22] contribution.
- **Phase 2: EUE Assessment.** Simulating EUE over the Long Term 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 enables AEMO to determine the RCT for each Capacity Year in the Long Term PASA Study Horizon.
- **Phase 3: Availability Class Requirements.** Determining the Availability Class requirements contemplated by WEM Rules 4.5.12(b)[23] and 4.5.12(c)[24]
- **Phase 4: Availability Curves.** Developing the two-dimensional duration curves required under WEM Rule 4.5.10(e)

2.3 Phase 1: Hourly load forecasting

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 DER[25] and in particular, behind-the-meter 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.

Reflecting this, our load forecasting methodology in the 2020 Reliability Assessment explicitly forecasted the load profile for each individual Capacity Year (allowing year-on-year variation), based on AEMO's forecasts of future DER growth and underlying demand. This was done by

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[21] AEMO distinguishes between operational demand and underlying demand. Operational demand refers to network demand, met by utility-scale generation and excludes demand met by behind-the-meter PV generation. Underlying demand refers to operational demand plus an estimation of behind-the-meter PV generation and the impacts of battery storage.

[22] Note that for this report our definition of DER includes behind-the-meter PV and battery storage, but not EVs.

[23] The capacity associated with Availability Class 1.

[24] The capacity associated with Availability Class 2.

[25] This includes behind-the-meter PV and battery storage, but for the purposes of this report (in contrast to AEMO's definition) not EVs.

creating hourly underlying demand forecasts[26] and subtracting hourly forecasts of behind-the-meter PV generation and battery storage contribution to create preliminary hourly operational forecasts, which were converted into a load profile. This load profile was then scaled to ensure alignment with the forecast operational 50% POE summer peak and annual sent-out energy consumption forecasts provided by AEMO.

This year, to align with the changes in our treatment of intermittent generation (described at high-level in Section 2.1 and in detail in Section 2.4.4), we have made changes to our load forecasting methodology. In particular, to preserve the cross-correlations between DER, utility-scale intermittent generation and the weather conditions which drive underlying demand, we create a load forecast (across the modelling horizon) for each of the five reference years. The behind-the-meter PV and battery capacity factors for a modelled hour are the historical capacity factors for that hour in each reference year, while the underlying load profile are based off the profile for that reference year. This process produces five hourly operational load forecasts.

Our approach to forecasting the load profile has five steps:

1. Create the underlying load profile: The underlying load shape is developed using historical sent out generation data (adding historical behind-the-meter PV generation to get underlying load) to derive a load shape and chronology for each reference year.
2. Scale the underlying load profile to forecasted values: Hourly underlying load forecasts for each year in the Long Term PASA Study Horizon are developed by scaling up the underlying load profile for each reference year to match the underlying 50% POE peak and expected underlying annual consumption forecasts for the respective Capacity Year.
3. Forecast hourly DER contribution: Using DER data provided by AEMO, we forecast five series (one for each reference year) of hourly behind-the-meter PV generation and behind-the-meter battery charge/discharge over the modelling horizon.
4. Create the preliminary operational load profiles (chronology and load shape): The hourly underlying load forecasts and hourly DER contribution forecasts for each reference year are combined and adjusted for losses to create five hourly operational load forecasts. These are processed into an operational load profile for each Capacity Year in each of the five reference years.

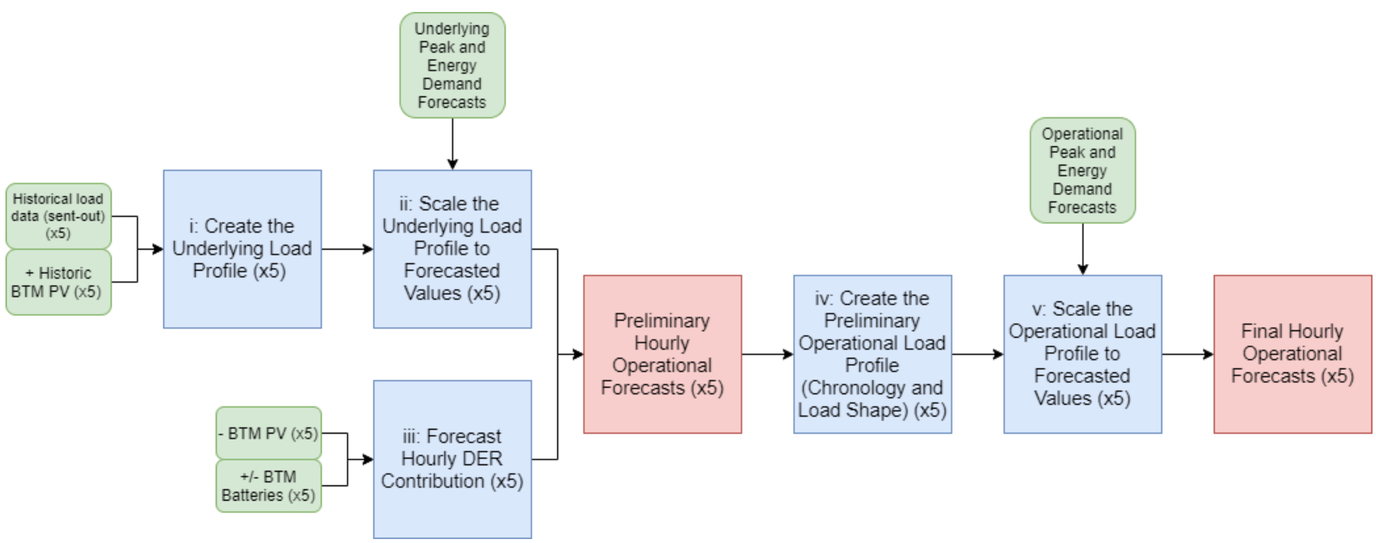
[26] Based on historical data and AEMO's underlying peak/energy consumption forecasts.

5. 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 scale the five operational load profiles to forecasted values, producing five 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 2.3.1 - 2.3.5), while red boxes refer to outputs.

Figure 4: Overview of the forecasting process



The hourly load forecasts are key inputs into Phases 2, 3 and 4. Specifically:

- They are used as the hourly load across the modelling horizon in the EUE assessment for each reference year, for each Capacity Year in the Long Term PASA Study Horizon.
- They form the basis of the load forecasts used in the Availability Class Requirement modelling. We use an average load profile[27], which is then adjusted to account for AC2 dispatch. This process creates AC2 adjusted hourly load traces which are used in the modelling.

[27] This is based on the average underlying load shape across the five reference years applied to the chronology implied by the most recent full Capacity Year (2019-20) and also uses the average DER profile across the five reference years to create an average DER contribution.

- They are also used to derive the two-dimensional duration curve defined in WEM Rule 4.5.10(e), which is developed into the Availability Curves by adjusting further the scaled profiles (in Section 2.3.5) to incorporate the requirements of WEM Rule 4.5.10(e). This is addressed in further detail in Section 2.6.

2.3.1 Creating the underlying load profile

We develop an underlying load profile by constructing underlying historical load duration curves (LDCs)[28] for each of the last five full Capacity Years (2015-16 to 2019-20). These are used to construct an average load shape and chronology for each reference year. As the historical total sent-out generation from AEMO reflects operational demand and excludes demand met by behind-the-meter PV generation, we add historical behind-the-meter PV generation[29] from each reference year (provided by AEMO) to the historical operational load data[30] before conducting the above analysis.

2.3.2 Scaling the underlying load profile to forecasted values

The next step in our load forecasting methodology is to scale the underlying load profiles for each reference year to match the underlying 50% POE peak forecast and expected underlying annual consumption in any given modelled year.

For each year of the Long Term PASA forecast horizon and each reference year we produce a forecast 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
- The shape of the profile is "close" to the reference year underlying load profile developed above.

We define a function F(h) (h $\in$ hours of the year) to achieve this, 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:

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

[29] Behind-the-meter PV generation will cause total sent generation to be lower than underlying demand.

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

- $\widehat{PROF}(h) = F(h) \times \overline{PROF}(h)$ 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. F(h) Is defined 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 underlying peak demand in that reference year
- e denotes the ratio of the underlying expected energy consumption forecast to the underlying hourly energy consumption
- m denotes the position in the profile where the curve flattens.
- 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.

Applying this function to the each of the five underlying load profiles gives us five hourly underlying demand forecasts across the modelling horizon.

2.3.3 Forecasting hourly DER contribution:

Our DER forecasts consist of the following data:

- Behind-the-meter PV generation
- Behind-the-meter battery charge and discharge

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

Behind-the-meter PV generation

Last year, we used statistical analysis (comparing actual generation to zero cloud cover generation in a period, and processing this into percentiles) to turn historical behind-the-meter PV capacity factor (provided by AEMO) into daily generation profiles (for each month) and an outage probability distribution function, these were used to simulate a behind-the-meter PV generation profile.

This year, for each of the five reference years, we simply apply the hourly (hour of the year) PV capacity factor for each of the historical reference years to each given hour within a modelled year. This is multiplied by the yearly/monthly PV forecasts provided by AEMO to get an hourly PV generation sequence across the modelling horizon for each reference year.

Behind-the-meter battery storage

Behind-the-meter batteries include installations in domestic and commercial properties, but do not include grid-connected storage facilities.

For behind-the-meter batteries, we apply the same approach as for behind-the-meter PV generation, applying the historical hourly net charge profile in each reference year to each year over the modelling horizon and multiplying these by the capacity forecasts provided by AEMO.

2.3.4 Creating the preliminary operational load profile

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

$$DL_{h(y),r} = UL_{h(y)} - DER_{h(y),r}$$

Where:

- $DL_{h(y),r}$ refers to the delivered load in hour h of the year y (h(y)) for reference year r,
- $UL_{h(y)}$ refers to the underlying load forecast in h(y) and
- $DER_{h(y),r}$ refers to the hourly DER contribution in h(y) for r.

The delivered loads are then adjusted by a weighted loss factor to add network losses, 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:

$$OL_{h(y),r} = DL_{h(y),r} \times \left(\left(LF^{RES} \times \frac{L^{RES}}{L^{RES} + L^{BUS}}\right) + \left(LF^{RES} \times \frac{L^{BUS}}{L^{RES} + L^{BUS}}\right)\right)$$

Where:

- $OL_{h(y),r}$ refers to the operational load in h(y) for reference year r,
- LF^{RES},LF^{RES}refer to the residential and business loss factors (respectively), and
- L^{RES},L^{BUS} refer to total forecast underlying residential and business load/demand for a given Capacity Year.

These preliminary operational load hourly forecasts are then processed into the operational load profile for each Capacity Year and reference 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 gives us a preliminary operational load profile for each forecast Capacity Year, for each reference year.

2.3.5 Scaling the operational load profile to forecasted values

Given that the peak forecasts provided by AEMO set the RCT and consequently form the basis of the Reliability Assessment, it is important that the peaks we use for our modelling match those provided by AEMO. In order to ensure this, we re-scale the five operational load profiles created in Section 2.3.4 using the function described in Section 2.3.2. This gives us five hourly load forecasts (one for each reference year) 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.

2.4 PHASE 2: EUE ASSESSMENT

We have used our bespoke model, CAPSIM[31] to conduct the EUE assessment. CAPSIM simulates the capacity gap (a simple arithmetic calculation subtracting load from available energy producing and capacity) for every hour[32] of every year, sequentially, given a specific generation mix, load profile, planned outage schedule and random forced outages. This assessment is conducted for the five reference years with intermittent profiles and DER forecasts varying by reference year. Both partially constrained network access (in the 2021-22 Capacity Year) and fully constrained network access (From the 2022-23 Capacity Year onwards) are modelled.

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 (energy producing and DSM capacity) 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 each of the five reference years, using the associated hourly load forecast (see Section 2.3) intermittent generation profile (see Section 2.4.4) and randomised forced outages (see Section 2.4.6); and using assumptions (common to all reference years) around Electric Storage Resource availability (see 2.4.3), and Planned Outages (see Section 2.4.5), 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=50 iterations and R=5 reference years above to estimate EUE for each modelled year as follows:

$$\mathrm{EUE(y)} = \frac{1}{R}\frac{1}{N}\sum_{r=1}^{R}\sum_{n=1}^{N}\sum_{h=1}^{H}\textbf{Unserved Energy (r, n, h)}$$

   a. EUE(y) is the EUE in year y, where y is one of ten Capacity Years in the Long Term PASA horizon

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

[32] 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.

    b. Unserved Energy(r,n,h) is the unserved energy in hour h of Capacity Year y as simulated under iteration n of reference year r.

4. We then divide EUE(y) by forecast annual energy consumption in year y to express EUE as a percentage.
5. If the percentage in Step 4 is less than or equal to 0.002% then we stop; the RCT is 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 is run over 50 forced outage iterations for each reference year (250 iterations in total) to generate a probability distribution of unserved energy and to estimate EUE for each year of the modelling horizon.

The above steps are a high-level summary of our modelling methodology for the EUE 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 are implemented in practice.

The rest of this section is structured as follows:

- We first provide an overview of CAPSIM in Section 2.4.1
- We then provide an overview of our new approach to modelling network constraints (including both the partial and full network constraints) in Section 2.4.2
- We discuss our proposed approach for the treatment of ESRs in Section 2.4.3
- We discuss how intermittent generation is modelled in CAPSIM in Section 2.4.4
- We then explain our methodology for developing a Planned Outage schedule in Section 2.4.5
- Finally, we describe our approach towards modelling Forced Outages in Section 2.4.6

2.4.1 Overview of CAPSIM

In 2019, we 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 to the corresponding load in the same hour.

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

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

2.4.2 Application of network constraints

As part of the WEM reforms, fully constrained network access is expected to be introduced from 1 October 2022. While historically (with the exception of the Constrained Access Facilities), the SWIS has operated under an unconstrained network access regime, the introduction of fully constrained network access means that dispatch in the WEM will need to account for network constraints.

As a result of this, for the 2021 Reliability Assessment we have implemented a new methodology for the modelling of network constraints. For both the partial and the full network constraints, we create a constraint optimisation model to take into account the network constraints[33]. The model maximises total available generation subject[34] to:

- Network constraints
- The unconstrained available generation[35] from each facility and
- Hourly load

This enables us to determine the generation that is available to meet load in each hour, after accounting for network constraint related curtailments and outages.

An optimisation of this nature would end up with extremely high solve times if we were to run it for every hour of the year, for each of the 250 iterations. Hence, we have developed a heuristic to reduce the number of solves required[36]. This heuristic triggers the application of the constraint optimisation model when the capacity gap (available capacity less load) for a period prior to the application constraints is lower than a threshold.

2.4.3 Treatment of Electric Storage Resources

Under the Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020, ESRs (whether standalone or part of a hybrid facility) that are not part of a Non-Scheduled Facility will have an obligation to offer in capacity during the Electric Storage Resource Obligation Intervals (ESROIs) in a Trading Day.

We have assumed that the ESROIs occur from 4 P.M. to 8 P.M. each Trading Day, as these times generally coincide with peak operational demand. We have also assumed that a given ESR will

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[33] We have used the same model and methodology for the partial network constraints and the full network constraints (rather than applying the methodology from the 2020 Reliability Assessment for the 2021-22 Capacity Year) to ensure consistency between Capacity Years.

[34] Note that the maximisation of total available generation that takes place under our constraint optimisation mode differs from how the full network constraint dispatch optimisation will operate in practice. In particular, the full network constraint dispatch will seek to meet load at the lowest total system cost and will explicitly reflect bids from generators. Our optimisation does not seek to minimise cost and it is agnostic about whether a generator that is backed off is high-cost or low-cost. This is irrelevant from the perspective of the Reliability Assessment as the objective of the assessment is to determine how much capacity is available to meet load after partial/full network constraint curtailments (irrespective of cost).

[35] Total generation less planned and forced outages.

[36] It is unnecessary to perform a full optimisation solve in an hour where unserved energy is extremely unlikely (e.g. periods of low load).

discharge according to an approximation of the ESR's maximum possible discharge across the assumed ESROIs. Our approximation has been calculated as the minimum of the MW power rating and the MWh storage capacity divided by four to reflect the four hours over the assumed ESROIs:

$$\widehat{Discharge}_e(h) = \begin{cases} min\left[P_e, \frac{S_e}{4}\right] \; \forall \; h \in ESROIs, \\ 0 \; otherwise \end{cases}$$

Where:

- $\widehat{Discharge}_e(h)$ is our approximation of the maximum dispatch of ESR e in hour h,
- P_e is the MW power rating of ESR e
- S_e is the MWh storage capacity of ESR e.

This approximation ensures that a given ESR is providing capacity over the assumed ESROIs but is not infeasibly dispatched above its ability to provide power or energy[37]. It also makes the simplifying assumption that ESRs will not be available in assumed non-ESROIs. Forced outages will be applied to the ESRs using the methodology in Section 2.4.6. We also assume that ESR charging will not take place in any period where there is a risk of unserved energy so there will be no impact on unserved energy or Availability Class 1 capacity.

For hybrid facilities comprising an intermittent resource and an ESR, we model the intermittent generator and ESR as two separate components: the ESR component is modelled as described above, while the intermittent component is modelled as described in the next section.

Note also that stand-alone ESR facilities (but not hybrids) are considered AC2 under the WEM Rules. This has led to consequential changes to our Availability Class Requirement modelling. Please see Section 2.5 for a discussion of these changes.

2.4.4 Treatment of intermittent generation

As noted in Section 2.1, our approach to modelling intermittent generation has been updated this year to reflect the impacts of intermittent variability on EUE.

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[37] As an example of how this would work in practice, consider a 5 MW/18 MWh ESR. In this case, the ESR would have an available capacity of $\min(5, \frac{18}{4})$ i.e. 4.5 MW from 4 P.M. to 8 P.M. each day and 0 MW outside of this time. If this ESR instead had a power rating of 3 MW (while maintaining the same storage capacity), then the power rating would set the maximum possible discharge and the ESR's available capacity during the assumed ESROIs would be 3 MW.

This year, we have developed intra-day hourly profiles for each of the five reference years (Capacity Years 2015-16 to 2019-20). This means that the profile for each generator for a given reference year reflects the historical generation patterns[38] (or participant estimated generation patterns[39] for new facilities) for that year. Our process is as follows:

- For each reference year, for each month (Jan, Feb, ..., Nov, Dec), we assign an intra-day hourly profile to each intermittent generator.
  - This means each intermittent generator has 5 x 12 intra-day hourly profiles (one for each month of the year for each of the five reference years).
- Hence, $\overline{Gen_{r,h,m}} = \left(\frac{\sum_{d\,(days) \in Month\ m} Gen_{r,h,d}}{\#\ days\ in\ month\ m\ of\ \mathrm{ref}\ year\ r}\right)$
- For a given intermittent generator:
  - $\overline{Gen_{r,h,m}}$ denotes the average generation (MW) in hour h of month m of reference year r.
  - $Gen_{r,h,d}$ denotes the historical or estimated generation value in hour h of day d (in month m) of reference year r.

Note that the $\overline{Gen_{r,h,m}}$ value for a given intermittent generator is scaled to reflect the ratio of the RCT to total Capacity Credits in each modelled year.

2.4.5 Planned outages

For Planned outage scheduling, we use Market Participant provided scheduled outage dates[40] as a starting point but we then evaluate 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[41].

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[38] Based on their non-loss adjusted metered quantities.

[39] Note that the participant-provided estimated generation does not cover the last 6 months of the 2019-20 Capacity Year. AEMO has provided extended estimated generations for some generators based on correlations with other facilities, and for the remaining facilities we have filled in the gap using the average intra-day profile over the reference years which do have data.

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

[41] Note that this approach is not designed to exactly replicate the process AEMO 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.

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

We then scale up our weekly peak load forecasts as follows:

- For Capacity Years that match up with the Medium Term PASA horizon (2021-22, 2022-23 and early 2023-24), we scale the hourly operational load forecasts created in Section 2.3.5 using the seasonal and annual scaling factors described above.
- For Capacity Years outside of the Medium Term PASA horizon (late 2023-24 onwards) we use the scaling factors derived for the latest season for which Medium Term PASA forecasts are available (i.e., Q3 and Q4 of 2022-23, and Q1 and Q2 of 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 Medium Term PASA.

Table 4: Average percentage difference between Medium Term PASA and 2021 Reliability Assessment weekly peak load forecasts

Quarter/Calendar Year	2021	2022	2023	2024
Jan-Mar	N/A	19.62%	16.49%	14.06%
Apr-Jun	N/A	7.04%	4.85%	N/A
Jul-Sep	N/A	8.08%	7.00%	N/A
Oct-Dec	7.16%	5.93%	6.79%	N/A

The planned outage scheduling is conducted as follows (for each reference year):

1. Subtract the weekly peak load (as derived above) from available generation 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 do not model opportunistic maintenance. This is because opportunistic maintenances are subject to AEMO'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.

2.4.6 Forced outages

Forced outages are 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.

CAPSIM generates 50 sequences of forced outages for each generator, for each of the five reference years (250 in total) across the modelling horizon.

Forced outage assumptions have been developed by analysing the 36-month historical forced outage rate (FOR).

We also develop a mean time to repair (MTR) value which denotes the amount of time a plant is offline following a forced outage event. This value is derived by examining the historical downtime (also from the most recent 36 Months) of all facilities (both intermittent and scheduled generation), following a forced outage. Outages are classified into outage "events" by identifying sequential outage periods from the same facility. The mean duration of all outage events for a facility is the raw MTR. After this calculation is completed, plants are classified into short (12 hours), medium (24 hours), and long (144 hours) duration outage plants based on their raw

MTR[42]. For new plants or plants which have no historical outages we have assumed forced outage rates and MTR are similar to current plants of a similar technology.

2.5 Phase 3: Availability Class requirements

Having determined the RCTs for each year, the next phase 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. As noted in Section 2.1, AC2 capacity in this year's modelling include stand-alone ESR capacity in the 2023-24 Capacity Year. This has led to consequential changes to our methodology for modelling the dispatch of AC2 capacity.

The Availability Class requirements modelling does not use five reference year traces; instead, we use the average intermittent profile across the five reference years and the load forecasting process in Section 2.3 uses the hourly (hour of the year) average behind-the-meter PV and battery capacity factors (again, across the five reference years) to create one 'average' load forecast.

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

2.5.1 Determine WEM Rule 4.5.12(b)

WEM Rule 4.5.12(b) requires the determination of the minimum energy producing 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*

---

42 Briefly, where the raw MTR of a facility is ≥12 hours, the final MTR is 12 hours; where the raw MTR is > 12 hours and ≤ 96 hours, the final MTR is 24 hours; and where the raw MTR is >96 hours the final MTR is 144. This ensures that only plants that consistently go on long duration outages are classified as long duration plants.

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…

We calculated the minimum generation requirement (AC1 capacity) by simulating unserved energy (for the second and third years of the Long Term PASA Study Horizon) as described in Section 2.4 with five differences:

1. First, an average load forecast is created using the average underlying load shape[43] and the average historical hour-of-the-yearly behind-the-meter PV and battery capacity factors. Note also that the average intermittent generational profiles (for each facility) across the five reference years are used in the modelling to align with this forecast.
2. Second, AC2 capacity is modelled in greater detail to take into account the constraints around the availability of DSM providers[44] and ESR capacity. In short, a given level of AC2 capacity is allocated between stand-alone ESR and non-Interruptible Load DSM capacity according to the ratio of the capacity between the two in that Capacity Year. ESR is dispatched during the period from 4 P.M. to 8 P.M. for each day (see Section 2.4.3) and we then allocate DSM throughout the year using an optimisation model that dispatches DSM to minimise the peak (net of ESR) subject to scheduling and availability constraints. See below for further details on our approach to modelling AC2 capacity.
3. Third, we specify a planning margin in the market model that represents the Ancillary Services requirement and Ready Reserve Standard contemplated in WEM Rule 3.18.11. We

[43] Applied to the chronology implied by the most recent full Capacity Year (2019-20)

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

model a planning margin that varies based on the scaled[45] Capacity Credits of the two largest units.

4. Fourth, 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.
5. Finally, for each year of the relevant Reserve Capacity Cycle, we iterate the model to reallocate the amount of AC2 and AC1 (reducing the AC1 capacity as AC2 capacity 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 energy producing capacity at which the EUE equals 0.002% of expected demand then sets the minimum energy producing capacity.

AC2 Modelling Methodology

AC2 capacity in this year's Availability Class requirements modelling consists of both DSM and stand-alone ESR capacity. As ESR in our modelling is dispatched according to our approximation of the Facilities maximum possible discharge between 4-8 P.M>, rather than to minimise the peak, we must dispatch DSM after ESR to ensure that the total peak is minimised. Our approach to modelling the dispatch of both DSM and ESR capacity is detailed further below:

1. Forecast sequential hourly load for the year using the methodology described in Section 2.3, applying the average historical DER profile across the five reference years to create one 'average' load forecast for use in the modelling.

[45] We use a scaled planning margin as the capacity of the largest unit and the second largest unit are 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.

2. For a given input level of AC2 capacity, the capacity is split between DSM and ESR based on the ratio between the modelled total Capacity Credits of non-interruptible load DSM and ESR in the second and third Capacity Years of the Long Term PASA Study Horizon.
3. Model stand-alone ESR generation as our approximation of maximum possible discharge from 4 P.M. to 8 P.M. and 0 MW outside of these times. This generation is deducted from the hourly load forecasts to create a "residual load" - net of ESR generation.
4. For DSM we use an optimisation model which, given the forecasted hourly residual 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 residual 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[46] dispatch with the lowest overall peak load.
5. Finally, adjust the load profile used in the market modelling by subtracting the forecasted AC2 dispatch in the relevant hours (from Steps 3 & 4 above). This adjusted load profile represents the "effective demand" and is used in the modelling of the minimum energy producing capacity contemplated by WEM Rule 4.5.12(b).

2.5.2 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).*

[46] 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 also unlikely to be optimal.

This is a straightforward calculation that is computed by subtracting the minimum energy producing capacity, calculated above (see Section 2.5.1) from the RCT for the relevant Capacity Year.

2.6 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 we use to determine the two Availability Curves (WEM Rule 4.5.10(e)).

2.6.1 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 (applied in the first 24 hours) and 50% POE peak LDC (applied thereafter).

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 first 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 is done using the average operational load profile developed for the Availability Class Requirement modelling (Section 2.5), by scaling this profile up to the 10% POE operational peak forecasts provided by AEMO using the same process described in Section 2.3.5.

    b. We then estimate the forecast load for the remaining hours (25-8,760) assuming a 50% POE peak forecast under the expected demand growth scenario (i.e. the load forecasts created for the Availability Class Requirement in Section 2.5).

    c. We then use a smoothing function[47] to smooth out the LDC in the first 72 hours.

    d. We then convert the hourly LDC to Trading Intervals (as required by WEM Rule 4.5.10(e)) 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 also be 4000 MW for 8:30 A.M.

2. We add the reserve margin, Intermittent Load (IL) allowance and LFAS component of the WEM Rule 4.5.9(a) calculation (as provided by AEMO) on top of the LDC as required by WEM Rule 4.5.10(e)(ii).

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

3 RESULTS

3.1 EUE ASSESSMENT

The EUE assessment indicates that for all Capacity Years of the Long Term PASA Study Horizon (Capacity Years 2021-22 to 2030-31) 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 EUE 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 EUE assessment

Capacity Year	RCT (MW) [a]	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)
2021-22	4,356	3,686	17,127,210	342.54	3.86	0.0000225%	0.00
2022-23	4,380	3,708	17,018,680	340.37	3.61	0.0000212%	0.00
2023-24	4,396	3,733	16,841,560	336.83	0.87	0.0000051%	0.15
2024-25	4,409	3,736	16,666,840	333.34	7.97	0.0000478%	2.22
2025-26	4,410	3,739	16,521,750	330.44	1.89	0.0000114%	0.00
2026-27	4,427	3,755	16,395,180	327.90	9.45	0.0000576%	0.00
2027-28	4,432	3,750	16,263,580	325.27	3.65	0.0000224%	1.06
2028-29	4,441	3,767	16,160,460	323.21	9.06	0.0000560%	1.45
2029-30	4,444	3,769	16,050,720	321.01	39.12	0.0002437%	1.92
2030-31	4,443	3,772	15,986,800	319.74	4.57	0.0000286%	N/A

a. Set by WEM Rule 4.5.9(a) 10% POE under the expected growth scenario + reserve margin +LFAS requirement + IL Allowance.

EUE in this year's EUE assessment is higher across all Capacity Years than in the 2020 Reliability Assessment but remains well under the 0.002% limit. Unserved energy is higher in this year's EUE assessment due to the following:

- **The impact of modelling five reference years**: There are two reference years (2016-17 and 2018-19) with particularly high winter loads; which due to low intermittent generation over winter decreases capacity margins and significantly increases the risk of UE[48]. These two reference years are driving the majority of the UE and represent more extreme conditions (in the sense of having higher winter loads and lower intermittent generation over winter periods at risk of UE) than the approach used in the 2020 Reliability Assessment where we used a five-year average load profile and average intermittent profiles. Because of the small amount of unserved energy in the EUE assessment, a non-zero level of unserved

[48] We note that the 2017-18 reference year also has a large proportion of winter periods in its top 50 peak periods, but unlike the 2016-17 & 2018-19 reference years the majority of the 2017-18 reference year's winter peak periods occur in August which has generally higher intermittent generation in the evening than June or July.

energy in any given reference year will significantly increase our estimate of EUE in relative terms.

- Constraints (and new entry driving congestion): As noted in Section 2.4.2, in the 2021-2022 Capacity Year we only model partial network constraints but from the 2022-23 Capacity Year onwards we model fully constrained network access. The maximum partial constraint curtailment in periods with unserved energy in 2021-22 is 86 MW whereas the maximum full constraint curtailment in periods with unserved energy is 312 MW, which is a substantial increase. This is partly due to the full constraints themselves but is mainly driven by the entrance of several new generators in congested areas of the network. As total capacity is scaled down to meet the RCT, the entrance of a new facility which is constrained down frequently reduces the modelled capacity of facilities which are not constrained down frequently[49]. Where a constraint binds and reduces generation in periods at risk of UE, this can increase the risk of UE or increase the magnitude of UE where UE already exists.

We note that the EUE for the 2029-30 Capacity Year is significantly higher than in 2020 Reliability Assessment. The high level of EUE in this Capacity Year occurs only for the 2016-17 and 2018-19 reference years and is driven by the interaction of planned outages[50] and high winter loads for these reference years, leading to lower capacity margins.

In particular, in the 2029-30 Capacity Year for the 2016-17 reference year, there is 302.97 MW[51] (scaled capacity) of Planned Outage on 31 July 2030, which has a particularly high evening peak. In the 2018-19 reference year, there is a high level (736.92 MW of scaled capacity) of planned outage in the first week of September 2030, where the 2018-19 reference year has higher loads for this period than other reference years. While these planned outages are common across all

[49] As a simplified example, consider a hypothetical Capacity Year with a RCT of 4000 MW and total unscaled capacity of 4000 MW, assume capacity of Facilities in non-congested areas is 3500 MW while Facilities in congested areas have a capacity of 500 MW. If new capacity of 1000 MW enters in congested areas, then total capacity equals 5000 MW and total capacity must be scaled down to the RCT at a scaling factor of 0.8. Applying this scaling factor to the capacity in congested areas gives a scaled capacity of 1200 MW while in non-congested areas the scaled capacity would be 2800 MW. This means that there is 700 MW less non-congested generation available when Facilities in congested areas are curtailed.

[50] These outages have just passed our planned outage scheduling process for each reference year (see Section 2.4.5 and Appendix 3.3A.4.1).

[51] Based on information provided by market participants under WEM Rule 4.5.3.

reference years, for the 2016-17 and 2018-19 reference year these planned outages coincide with high winter loads and low intermittent generation leading to lower capacity margins and significantly increases the risk of unserved energy.

Table 6 shows total EUE across the modelling horizon, by hour and month. Table 7 shows EUE for each capacity year across the five reference years. We note that unserved energy is most likely to occur in winter when a low amount of intermittent generation is available and only occurs from 5 P.M. to 8 P.M.in the evening. The majority of unserved energy is driven by the 2016-17 and 2018-19 reference years.

Table 6: EUE by month/hour

Month/Hour	17:00	18:00	19:00	20:00
January	0.00	0.05	0.00	0.00
February	0.00	1.58	1.34	0.39
March	1.13	5.68	3.68	0.00
April	0.00	0.00	0.00	0.00
May	0.00	0.00	0.00	0.00
June	2.92	14.78	1.17	0.00
July	1.46	18.77	1.70	0.03
August	0.00	11.04	3.44	0.17
September	0.00	8.74	5.66	0.18
October	0.00	0.00	0.00	0.00
November	0.00	0.00	0.00	0.00
December	0.00	0.13	0.00	0.00
Total	5.51	60.78	16.99	0.77

Table 7: EUE by Capacity Year/reference year

Capacity Year/Reference Year	2015-16	2016-17	2017-18	2018-19	2019-20
2021-22	3.32	0.00	0.54	0.00	0.00
2022-23	0.00	3.61	0.00	0.00	0.00
2023-24	0.00	0.00	0.00	0.87	0.00
2024-25	0.66	0.00	0.87	5.26	1.18
2025-26	0.00	0.61	0.17	1.11	0.00
2026-27	0.79	4.82	0.00	3.84	0.00
2027-28	0.14	0.68	0.15	2.68	0.00
2028-29	0.40	2.42	0.00	6.24	0.00
2029-30	0.00	21.64	0.98	16.50	0.00
2030-31	0.00	0.45	0.00	4.12	0.00
Total	5.32	34.23	2.70	40.61	1.18

3.2 Availability Class requirements

Table 8: Availability Class requirements (2022-23 and 2023-24)

	2022-23	2023-24
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1	3,730	3,496
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2	650	900

Table 9: Comparing 2021 Availability Class requirements to 2020 (2020 results in parentheses)

2022-2023	
WEM Rule 4.5.12(b): Minimum capacity required to be provided by Availability Class 1	
Minimum capacity	3,730 (3,371)
RCT	
RCT	4,380 (4,421)
WEM Rule 4.5.12(c): Capacity associated with Availability Class 2	
DSM	650 (1,050)

The minimum capacity required to be provided by AC1 has increased by 359 MW for the 2022-23 Capacity Year while the maximum capacity associated with AC2 has decreased by 400 MW. From the 2023-24 Capacity Year, the maximum AC2 capacity increase to 900 MW.

The decrease in maximum AC2 capacity in 2022-23 reflects:

- Lower capacity margins in 2022-23 in general (reflected in higher unserved energy in the EUE assessment in the 2021 EUE assessment compared to 2020).
- Planned outages in the shoulder season (when DSM has been exhausted). In the first week of October 2022 (which for this Capacity Year, is where unserved energy begins to occur as we iterate up AC2 capacity), there is 819.62 MW of (scaled) capacity on planned outage, this leads to lower capacity margins for this period and increase the likelihood of unserved energy.

As noted in Section 2.5.1, our Availability Class requirements modelling methodology has been updated this year to account for stand-alone ESRs for the 2023-24 Capacity Year. Unlike DSM, ESR capacity is not exhausted within 200 hours, ESR capacity is therefore able to mitigate EUE in the shoulder seasons within the assumed ESROIs (4 P.M. to 8 P.M.). Conversely, where there is a high risk of UE outside of the assumed ESROIs ESRs are not able to be dispatched in our modelling. In this year's demand forecasts the great majority of high load periods occur within the period from 4 P.M. to 8 P.M., so ESR capacity is able to mitigate UE. This combined with higher overall capacity margins in the 2023-24 Capacity Year compared to the 2022-23 Capacity Year has meant that the maximum AC2 capacity has increased.

3.3 Availability Curves

The Availability Curves (WEM Rule 4.5.10(e)) are illustrated in Figure 5 and Figure 6.

Figure 5: Availability Curve (2022-23 Capacity Year)

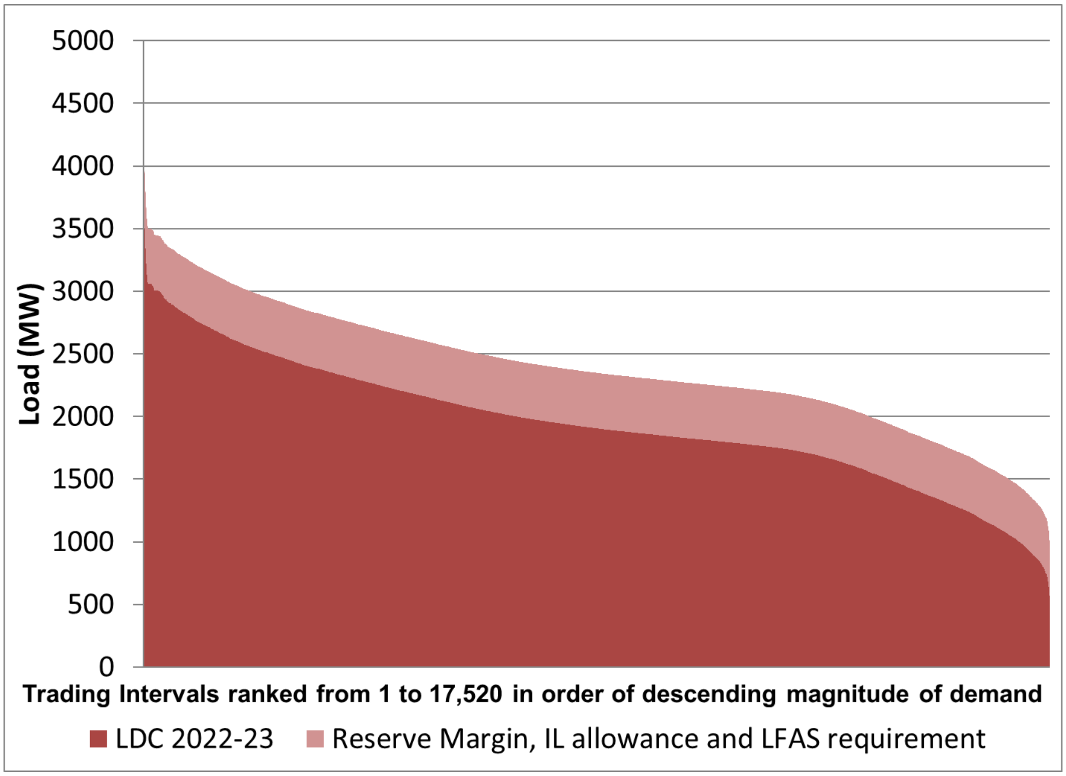
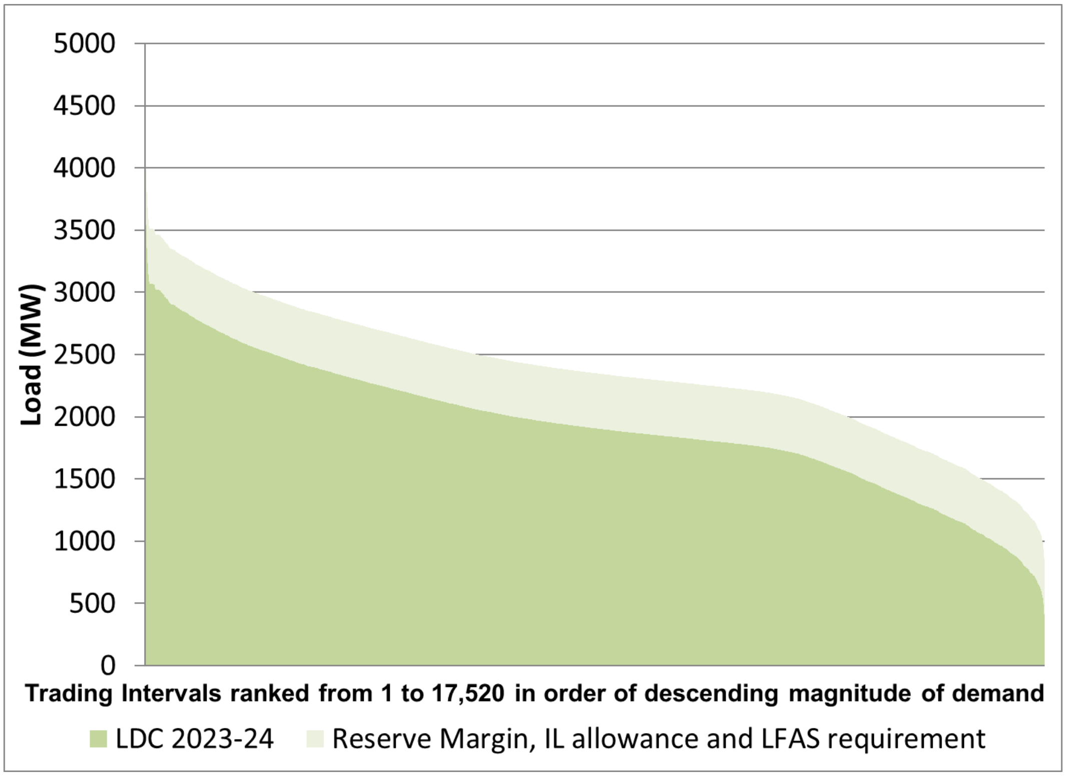


Figure 6: Availability Curve (2023-24 Capacity Year)



Appendix A Modelling assumptions

A.1 Capacity Credits

The amount of Capacity Credits assumed for a facility is summarised in this section.

As noted in Section 2.4, for each year of the Long Term PASA Study Horizon, we assume Reserve Capacity (energy producing and DSM capacity) equals the forecast 10% POE peak (operational) quantity plus a reserve margin and a LFAS quantity required for Minimum Frequency Keeping Capacity for normal frequency control as specified in WEM Rule 4.5.9(a). To do this we pro-rate the assumed Capacity Credits (provided by 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:

$$\widehat{CC_i} = CC_i{}^{52} \times \frac{10\%\ POE\ peak + Reserve\ Margin + LFAS}{\sum_{j \in all\ facilities} CC_j}$$

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 assumed to be assigned Capacity Credits, we model the plant commencing when its capacity obligations begin.

There will be two retirements during the Long Term 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, when the

[52] For scheduled generators CC_i denotes the Capacity Credits the facility is applying for. For non-scheduled (intermittent) generators, CC_i denotes the facilities' average non-zero hourly generation (based on historic or 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 peak load intervals only).

Muja units retire a proportion of scheduled generation is removed from the generation mix, and intermittent generation makes up a larger proportion of the remaining generation.

A.3 Intermittent generation

We have applied the methodology set out in Section 2.4.4 to historical metered generation (existing facilities) and estimated generation (new facilities) to derive intra-day hourly profiles for each intermittent facility. This has resulted in 12 intra-day profiles for each intermittent facility, for each of the five reference years.

A.4 Outages

A.4.1 Planned outages

Planned outage assumptions have been developed using the methodology described in Section 2.3.3. All planned outages (across all reference years) have passed our planned outage scheduling process and will proceed as provided.

A.4.2 Forced outages

FOR assumptions and MTR values have been developed by analysing the 36-month historical (FOR) and MTR (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. Assuming a FOR of 0% is unrealistic as equipment is unlikely to have a zero failure rate. The majority of FOR assumptions remain similar to last year.

A.5 Demand forecasts

Table 10 summarises the percentage of top 50 peak periods in each Capacity Year/reference year that fall within the winter period (June - August)

Table 10: Seasonal distribution of top 50 peak periods by Capacity Year/reference year (% in winter)

Capacity Year/Reference Year	2015-16	2016-17	2017-18	2018-19	2019-20
2021-22	10%	36%	38%	28%	2%
2022-23	14%	42%	44%	32%	2%
2023-24	14%	42%	44%	34%	4%
2024-25	16%	42%	46%	38%	4%
2025-26	16%	44%	46%	42%	4%
2026-27	18%	44%	48%	42%	4%
2027-28	18%	46%	48%	42%	4%
2028-29	18%	46%	52%	42%	4%
2029-30	18%	48%	52%	44%	4%
2030-31	18%	48%	52%	44%	4%

A.6 Planning Margin

The minimum energy producing capacity requirement prescribed by clause 4.5.12(b) of the WEM Rules and used in the planned outage scheduling in Section 2.4.5 is modelled by assuming a planning margin equivalent to applying the Ready Reserve Standard defined in clause 3.18.11A and the Spinning Reserve requirement in clause 3.10.2. As mentioned previously, this margin is calculated as the capacity of the largest generator at a point of time and 70% of the capacity of the second-largest generator, minus the total interruptible load capacity.

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

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

Table 11 shows our unscaled planning margin assumption by Capacity Year.

Table 11: Unscaled planning margins by Capacity Year(s)

Capacity Year(s)	Planning margin (MW)
2021-22	518.06
2022-23 to 2030-31	524.22

For the minimum energy producing 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 is based on the pro-rated capacity as follows (see Section 4.1 for further detail):

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

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:

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

Table 12 summarises the scaled planning margin assumptions for the Availability Class Requirements modelling

Table 12: Scaled planning margin for WEM Rule 4.5.12(b)

Capacity Year(s)	Unscaled Planning margin (MW)	Scaling Factor	Scaled Planning Margin
2022-23	524.22	0.85	446.34
2023-24	524.22	0.84	441.09

Glossary

Table 13 presents a glossary of the terms used in this document.

Table 13: Glossary

Term	Definition
Behind-the-meter	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 Demand Side Programme Facility.
Demand side programme (DSP)	A Facility registered in accordance with clause 2.29.5A of the WEM Rules.
Distributed energy resource (DER)	DER technologies refers to small-scale embedded technologies that either produce electricity, store electricity, or manage consumption, and reside within the distribution system, including resources that sit behind the customer meter. Any generators that are connected to the distribution network that are assigned Capacity Credits are not included in the definition of DER technologies, for example Northam solar farm.

Term	Definition
	Note that for the purposes of the Reliability Assessment, Electric vehicles are excluded from this definition.
Electric Storage Resource (ESR)	One or more electric storage assets that are electrically connected to the SWIS at the same connection point.
Electric Storage Resource Obligation Intervals (ESROI)	A Trading Interval in which an Electric Storage Resource Obligation Quantity for an Electric Storage Resource applies.
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).
Interruptible Load	A Load through which electricity is consumed, where such consumption can be curtailed automatically in response to a change in system frequency, and registered as such in accordance with clause 2.29.5 of the WEM rules.
Long Term Projected Assessment of System Adequacy (Long Term PASA)	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.
Reference year	A historical Capacity Year, with associated intermittent generation and DER profiles.

Term	Definition
Reserve Capacity Cycle	A four-year period covering the cycle of events described in clause 4.1 of the WEM Rules.
Reserve Capacity Target (RCT)	AEMO’s estimate of the total quantity of energy producing capacity 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.