Government of Western Australia
Department of Mines, Industry Regulation and Safety
Energy Policy WA

Reserve Capacity Mechanism Review

Stage 1 Consultation Paper

29 August 2022

Working together for a brighter energy future.

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Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage Systems
BRCP	Benchmark Reserve Capacity Price
CCGT	Combined Cycle Gas Turbine
CONE	Cost of New Entry
CT	Combustion Turbine
DSP	Demand Side Programme
EFORd	Equivalent Forced Outage Rate
ELCC	Effective Load Carrying Capability
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESR	Electric Storage Resources
ESS	Essential System Services
EUE	Expected Unserved Energy
FCESS	Frequency Control Essential System Services
ICAP	Installed Capacity
IRCR	Individual Reserve Capacity Requirement
LOLE	Load of Load Expectation – the probability of an outage occurring in a given time period
LOLEv	Loss of Load Events – the number of discrete outages
LOLH	Loss of Load Hours – the number of hours of outage
MRI	Marginal Reliability Index
NAQ	Network Access Quantity
NEM	National Electricity Market
OCGT	Open Cycle Gas Turbine
POE	Probability of Exceedance
RCM	Reserve Capacity Mechanism
RCOQ	Reserve Capacity Obligation Quantity
RCMRWG	RCM Review Working Group
RCP	Reserve Capacity Price
RLM	Relevant Level Methodology
SWIS	South West Interconnected System
UCAP	Unforced Capacity
VCR	Value of Customer Reliability

Term	Definition
VoLL	Value of Lost Load
WEM	Wholesale Electricity Market

Executive Summary

The Reserve Capacity Mechanism Review

The Coordinator of Energy (Coordinator), in consultation with the Market Advisory Committee (MAC), is reviewing the Western Australian Reserve Capacity Mechanism (RCM) under clause 2.2D.1 of the Wholesale Electricity Market (WEM) Rules. The RCM Review also incorporates the Coordinator's first review of the Planning Criterion under clause 4.5.15 of the WEM Rules.

The review is being conducted in three stages:

- Stage one focussed on the definition of reliability and the characteristics of the capacity needed in future years, including the Planning Criterion, the methods for assigning Certified Reserve Capacity (CRC) and the Benchmark Reserve Capacity Price (BRCP).
- Stage two will assess how the outcomes of stage one affect the operation of other parts of the RCM, including outage scheduling, the refunds mechanism and the Individual Reserve Capacity Requirements (IRCR).
- Stage three will deliver the detailed design and any necessary transitional arrangements.

The MAC has constituted the RCM Review Working Group (RCMRWG) to support the Coordinator's work. More information on the RCM Review is available from the Energy Policy WA (EPWA) website[1], including the Scope of Works for the review, the Terms of Reference for the RCMRWG, papers for RCMRWG and MAC meetings and detailed minutes for each meeting. An updated timetable for the review stages is included in Appendix A.[2]

Call for Submissions

This consultation paper sets out the findings and recommendations arising from stage 1 of the RCM review. It presents proposals for changes to the design of the:

- Planning Criterion;
- RCM products;
- BRCP; and
- capacity certification process.

Stakeholder feedback is invited on the proposed changes to the RCM that are outlined in this consultation paper. Submissions can be emailed to energymarkets@dmirs.wa.gov.au. Any submissions received will be published on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00pm WST on Tuesday 27 September 2022. Late submissions may not be considered.

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1 RCMRWG: https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group
MAC: https://www.wa.gov.au/government/document-collections/market-advisory-committee

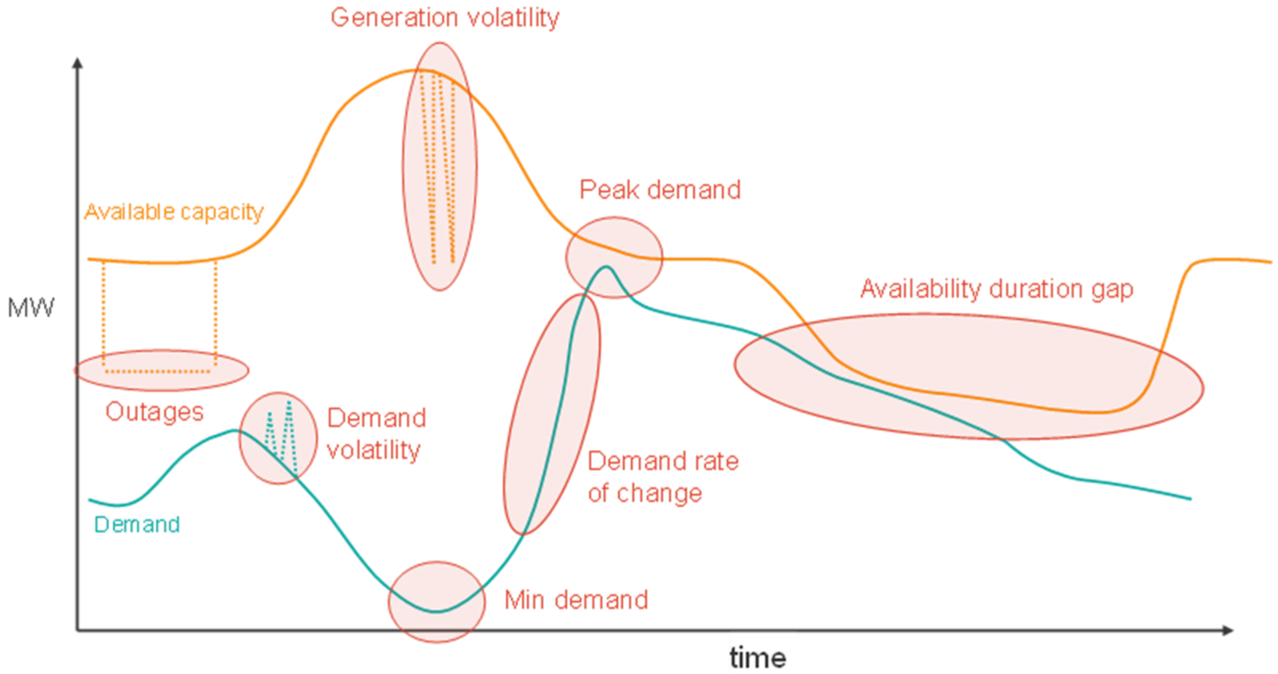
2 An indicative timetable was published as part of the Scope of Works and updated for this consultation paper.

Modelling Approach

How is system stress changing

The RCM is currently designed to address system conditions when system margins (i.e. the difference between supply and demand) are low. In the WEM, this normally occurs during hot summer periods when air conditioners are working hard. With increasing volumes of intermittent generation on the system – especially distributed photovoltaic (DPV) – and the projected mass uptake of electric vehicles, other kinds of system stress have been identified that have the potential to affect system reliability, as shown in Figure 1. Modelling was conducted to quantify the system stresses shown in Figure 1.

Figure 1: Sources of System Stress



Profitability of new entrants in the WEM

To consider the effects of different design options on facility builds and retirements, economic modelling was conducted simulating the profitability of new entrants in the WEM. This modelling will continue to be refined in stage two of the RCM Review as the design proposals are developed.

Conceptual Design Proposals and Rationales

Table 1 lists the design proposals by chapter and provides a high-level summary of the rationale for each proposal.

Table 1: Conceptual Design Proposals

Design Proposal	Rationale
Chapter 2: How has the RCM Review been conducted	
Conceptual Design Proposal 1 (retain the current approach): Retain the existing 'peak capacity' product to provide an explicit price signal several years ahead of the need for new capacity to meet peak demand and overall energy demand.	Modelling shows that peak demand will continue to cause system stress, even if the peak shifts to later in the day. It is considered that the RCM will remain a critical mechanism to ensure that there is sufficient capacity available to provide energy at peak times.
Conceptual Design Proposal 2 (retain the current approach): 1. The RCM will not include a specific product to manage minimum demand. 2. The RCM design and the capacity certification process will seek to avoid incentives for new facilities that could make minimum demand more difficult to manage, such as facilities with high minimum stable generation, and/or long start-up, minimum running or minimum restart times.	The modelling indicates that the low demand period in the middle of the day will continue to deepen. This is an important issue, but facilities capable of helping to manage minimum demand are unlikely to require large capital expenditure with multi-year lead times and other mechanisms to manage minimum demand will be more effective than designing a bespoke capacity product in the RCM.
Conceptual Design Proposal 3: Introduce a new capacity product into the RCM (alongside the existing peak capacity product) to incentivise flexible capacity that can start, ramp up and down, and stop quickly.	Increasing DPV penetration rates are driving a steepening and lengthening of the afternoon ramp. The modelling indicates that, from the late 2020s, the fast-ramping capacity required in these fleet development scenarios exceeds the available flexible capacity. Therefore, an explicit long-term price signal is needed to ensure that capacity is available that has sufficient fast-ramping capability.

Design Proposal	Rationale
Conceptual Design Proposal 4: It is not proposed that the Planning Criterion includes reference to volatility in the output of intermittent facilities. Volatility in operational load and intermittent generation over short timeframes can be managed through Essential System Services (ESS) and re-dispatch. The addition of the flexible capacity product, proposed under the Conceptual Design Proposal 3, is expected to provide adequate capacity that is capable of providing these services.	The modelling indicates that capacity with the flexibility needed to address volatility from demand and intermittent generation will be met by the flexible capacity product under design proposal 3. Therefore, it is considered that this volatility can continue to be managed through the ESS market.
Chapter 3: Review of the Planning Criterion	
Conceptual Design Proposal 5: The two current limbs of Planning Criterion will be retained, requiring sufficient capacity to: • meet the 10% probability of exceedance (POE) demand; and • achieve expected unserved energy (EUE) no greater than a specified percentage of expected demand.	The review of international capacity mechanisms shows that a single-limb criterion risks missing some aspects of reliability in the future, and the modelling demonstrates that the current limb (a) – the 10% POE peak measure – remains appropriate. Therefore, it is considered appropriate to retain a two limbed Planning Criterion, similar to the current Planning Criterion.

Design Proposal	Rationale
Conceptual Design Proposal 6: Amend the reserve margin so that: • sub-clause 4.5.9(a)(i) uses the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to forced outage, rather than a hardcoded percentage; and • sub-clause 4.5.9(a)(ii) refers to the largest contingency on the power system, rather than the largest generating unit. Introduce the proposed amendment to clause 4.5.9(a)(ii) to change the determination of the largest contingency for the calculation of the reserve margin, in time for the 2023 Reserve Capacity Cycle (for the Capacity Year starting on 1 October 2025).	Because the fleet of capacity providers and the quantity of expected forced outages changes from year to year, it is considered that limb (a) of the Planning Criterion could be improved by replacing the hardcoded percentage in sub-clause (i) with a methodology to determine the percentage for each capacity cycle as the expected forced outage rate at the time of system peak. Sub-clause (ii), as written, may no longer accurately capture the largest contingency on the South West Interconnected System (SWIS) during system peak, as the spinning reserve requirement can be set by a network contingency, which can be larger than the largest generator. Unless sub-clause (ii) is changed before the next reserve capacity cycle, the Reserve Capacity Target may be too low to ensure that there will be enough capacity if the largest contingency occurs at the same time as peak demand.
Conceptual Design Proposal 7: The target EUE percentage in the second limb of the Planning Criterion will remain at 0.002% of annual energy consumption.	One of the key objectives for the RCM Review is that any change to the RCM should not erode the level of system reliability currently provided for by the WEM Rules. Given the uncertainty about the future reference technology, and therefore about the BRCP, it is considered that there is currently no strong justification for changing the EUE target.
Conceptual Design Proposal 8: The Planning Criterion will include a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the capacity year from either the 10% or 50% POE load forecasts.	To implement Design Proposal 3, the key parameters driving the need for flexible capacity are the magnitude, slope, and duration of the most extreme ramp expected in the capacity year. Both the 10% and 50% POE load forecasts are to be considered to be consistent with the measure used for the peak capacity target, while accounting for potentially steeper ramps from lower minimum demand levels.

Design Proposal	Rationale
Chapter 4: Benchmark Reserve Capacity Price	
Conceptual Design Proposal 9: • The Economic Regulation Authority (ERA) will remain responsible for setting the detail of the method used to calculate the BRCP. • The WEM Rules will provide guidance for the ERA on the factors to be considered in setting the BRCP methodology.	While details of the BRCP determination can be delegated to a WEM Procedure, it is considered that the WEM Rules should provide guidance to the independent regulator for setting the BRCP.
Conceptual Design Proposal 10: • The WEM Rules will define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortised over the expected life of the facility. • A BRCP is to be calculated for each of the peak capacity product and the flexible capacity product, and the BRCP methodology must differentiate between the two, taking into account any differences between the reference technologies used for each product, where appropriate. • The ERA review of the BRCP methodology (under clause 4.16.9 of the WEM Rules) must consider the appropriate reference technology, the design life of the relevant facility, and identify any cost components that differ between the technology providing the peak capacity product only and that providing the peak capacity plus the flexible capacity product. • The ERA can review the BRCP methodology more frequently than every five years, if it considers that the reference technology has changed significantly, and must consult with stakeholders each time it does.	The analysis shows that an OCGT is likely to remain the new entrant with the lowest capacity costs for at least the next few years, but battery storage of an appropriate length will become lower cost than an OCGT at some point, or it will no longer be credible for OCGT to be built in Western Australia. At that point, the reference technology for the BRCP must change. In the meantime, both OCGT and battery storage can be designed to provide flexible capacity, so it is reasonable to expect that the reference technology for the peak capacity and flexible capacity products would be the same. The configuration of a facility that provides flexible capacity is likely to be slightly different to a facility providing peak capacity – for example, an OCGT likely faces additional costs to reduce its level of minimum generation.

Design Proposal	Rationale
Conceptual Design Proposal 11: • Where the RCM reference technology has the highest short-run costs in the fleet, the BRCP methodology can use the simpler gross cost of new entry (CONE) approach, as this will be the same as the net CONE. • Where the RCM reference technology does not have the highest short-run costs in the fleet, the use of net CONE approach would need to be considered together with all other factors that may influence investment decisions. • The BRCP will be set based on a facility located in the least congested part of the network. If there is no uncongested network location to accommodate the size of the lowest fixed cost technology, the Network Access Quantity (NAQ) regime may affect the choice of reference technology. This location will be considered as part of the ERA's regular review of the BRCP methodology.	Economic modelling indicates that, in the 2020s, when storage volumes are small, storage facilities can make short-run profits by charging when prices are low or negative and discharging in the peak hours. This means that setting the BRCP based on the gross fixed costs of a storage facility would allow a new entrant to recover more than its fixed costs, which may incentivise overcapacity in the SWIS. However, whether this will, in practice, lead to capacity oversupply needs to be carefully examined in the next stage of the RCM Review, as other factors, outside of the RCM may influence investment decisions in the short term. The types of capacity that are likely to be the reference technology are also likely to have some flexibility over where to locate, and therefore could be assumed to locate in a part of the SWIS where network congestion is minimal.

Design Proposal	Rationale
Conceptual Design Proposal 12: • The administered RCM price curve for the flexible capacity product will be the same as the one used for the peak capacity product, as defined in WEM Rule 4.29.1(b)(iv). • The capacity price paid to a facility providing flexible capacity will never be lower than the peak capacity price. • Proposed facilities will have the option to seek a five-year fixed price for flexible capacity, on the same basis as is currently available for peak capacity. A facility must opt for a fixed price for both products, it cannot select fixed price for one product and floating price for the other.	No compelling reasons were identified to use differently shaped price curves with different shapes for the two capacity products, so it is proposed to set the price curve for the flexible capacity product using the formula in WEM Rule 4.29.(b)(iv). To incentivize participants to make capacity available for both products from the outset, and prevent strategic withholding at the time of certification, it is important for existing facilities to be eligible for the same payment per MW as new facilities. Setting the capacity price for a portion of a facility that provides both products at the higher of the two product prices will avoid overcompensation, preserve the pricing signals for both products, and avoid incentives to withhold capacity. To maintain consistency with the peak capacity product, facilities providing flexible capacity would have an option to lock in fixed pricing for the flexible capacity for five years, but will only be awarded Capacity Credits if there is a shortage of capacity applying for the floating price option.

Design Proposal	Rationale
Chapter 5: Valuing Capacity when Certifying Capacity	
Conceptual Design Proposal 13: • The current Availability Classes will be removed from the WEM Rules. • The RCM will allocate facilities to one of three Capability Classes. • CRC allocation methodologies will be amended to consider hybrid facilities as a single entity. • Capability Class 1 facilities will be required to demonstrate fuel arrangements that enable them to run for 14-hours, with this requirement's practical implementation to be considered in stage 2 of the review. • Capability Class 1 facilities will be required to be available during all dispatch intervals, unless on an outage. The proposed design for Capability Class 2 is outlined in design Proposal 14 and the design for Capability Class 3 will be developed in stage 2 of the RCM Review.	Retaining the current Availability Classes is not a viable option, as they do not allow for hybrid facilities, which will be increasingly prevalent. Separating storage from its collocated wind or solar generation for certification purposes will increasingly work against the behaviour required in a world with more intermittent generation. The proposed 'Capability Classes' better align capacity allocation with firmness of delivery and with availability obligations. As the peak requirement changes over time, there will likely be sufficient intermittent generation to provide supply during the middle of the day. However, the duration gap analysis shows that, over time, the peak will flatten and extend, meaning that firm capacity will be needed overnight. It is considered that a 14-hour availability requirement to qualify as firm, unrestricted capacity is still valid as system peak events in recent years have occurred over several days during periods of sustained high temperatures and high demand. It is considered that relaxing this requirement now risks reducing the level of reliability provided for by the WEM Rules.

Design Proposal	Rationale
Conceptual Design Proposal 14: • AEMO will determine an availability duration requirement for new Capability Class 2 facilities, based on the capacity of the existing and committed fleet, and publish it in the ESOO, including forecasts for subsequent years. • Capability Class 2 facilities will receive CRC equal to their maximum instantaneous output pro-rated by the number of hours they can sustain this output divided by the availability duration requirement. • Proponents can request a five-year fixed availability duration requirement for a Class 2 facility but this request will only be accepted if the facility is needed to meet the reserve capacity target.	System stress modelling showed that, after 2030, firm capacity duration becomes a key factor in serving load overnight. There will be a ‘duration gap’ between the end of the evening ramp (when flexible capacity that ramps up to meet the evening peak load may have exhausted its availability) and sunrise (when behind the meter and grid scale solar start to ramp up). This means that facilities that cannot maintain output overnight would not provide the same contribution to system reliability as facilities that can. The RCM needs to incorporate a signal of the needed availability duration as the market evolves over the years, and incentivise new entrant technologies to meet the duration requirement. To address the uncertainty around the future availability duration target it is proposed to include an option for new facilities to be assessed based on the availability duration target that applied when they were first certified for five years from commissioning.

Design Proposal	Rationale
Conceptual Design Proposal 15: • CRC allocation will remain on an installed capacity (ICAP) basis, with refunds payable for any forced outage. • The reserve margin in the first limb of the Planning Criterion will be set at the greater of the fleet-wide Equivalent Forced Outage Rate (EFORd) and the largest contingency expected at system peak, with AEMO assessing both each year. • Where, over a three-year period, a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd. • The method for calculating EFORd will also account for forced outages reported at times the relevant facility had not been called to run. • A facility whose CRC has been reduced under clause 4.11.1(h) will be excluded from the calculation of fleet outage rate for the purposes of setting the planning criterion reserve margin.	It is considered that: • the current refund regime is working well to incentivise availability, particularly at times when the reserve margin is low; • an ICAP approach provides a stronger incentive for facilities to present all their capacity at peak times; • an ICAP approach better aligns facility payments with actual performance during the capacity year; and • AEMO has not exercised the option to reduce CRC where a specific facility has sustained poor outage performance under clause 4.11.1(h) because the rules do not provide guidance on the appropriate circumstances to exercise this discretion.
Conceptual Design Proposal 16: To ensure independent estimates of intermittent generator output, AEMO will procure expert reports to derive estimates of performance on behalf of participants.	To reduce the potential for bias, it is considered that it is appropriate to require AEMO to procure the expert report on behalf of participants.

Design Proposal	Rationale
Conceptual Design Proposal 17: The methodology to assign CRC to facilities in each of the different Capability Classes will differ by class as follows: • **Class 1**: Expected output at projected 10% POE peak ambient temperature; • **Class 2**: Expected output at projected 10% POE peak ambient temperature, adjusted for required availability duration; and • **Class 3**: To be confirmed in stage two of the RCM review.	It is considered that simple methods of CRC assessment remain appropriate for Class 1 and 2 facilities, but that an alternative method may be appropriate for Class 3 facilities. Three alternative methods for assigning CRC to intermittent generators have been proposed. EPWA will continue quantitative analysis to assess options to improve of the proposed CRC methods proposed, using common assumptions and inputs to ensure comparability, and propose a preferred option during stage 2 of the RCM Review. It is considered that the IRCR methodology needs to be adjusted to better align with the intervals used to determine CRC allocation. The IRCR methodology will also be considered in stage 2 of the RCM review.

1. Introduction

Under Clause 2.2D.1(h) of the WEM Rules, the Coordinator of Energy (Coordinator) has the function to consider and, in consultation with the Market Advisory Committee (MAC), progress the evolution and development of the Wholesale Electricity Market (WEM) and the WEM Rules. In addition, under clause 4.5.15 of the WEM Rules, the Coordinator is required to review the Planning Criterion at least every 5 years.

The Coordinator, in consultation with the MAC, is reviewing the Reserve Capacity Mechanism (RCM) under clause 2.2D.1 of the WEM Rules. The RCM Review also incorporates the Coordinator's first review of the Planning Criterion.

1.1 Background

1.1.1 The performance of the RCM

The RCM has operated successfully since 2004 by:

- providing incentives for investment in capacity that delivers the reliability outcomes valued by customers;
- reducing energy price volatility and the need for high energy price caps;
- providing confidence that reliability will be achieved by explicitly requiring capacity to be available, reducing the likelihood of costly intervention;
- incentivising entry of new types of capacity, including:
  - renewable generators, such as wind and solar;
  - Electric Storage Resources (ESR), such as batteries; and
  - Demand Side Programmes (DSP).

1.1.2 The need for the RCM Review

The RCM was implemented in the South West Interconnected System (SWIS) in 2004 to ensure sufficient capacity to maintain system reliability. The RCM has been subsequently amended to address issues with the initial mechanism and to account for market and system changes.

Since introduction of the RCM, the Planning Criterion has been reviewed twice, the last time in 2012, resulting only in minor changes because it was found to be appropriate overall.

The SWIS has changed substantially since 2012 – the installed capacity of transmission connected intermittent generation has more than doubled, the estimated installed capacity of distributed photovoltaic (DPV) has increased tenfold, and more than 1000 MW of coal and gas capacity has or is scheduled to retire by 2030.

The SWIS is now in a transition to a lower emissions energy system because of the decreasing cost of renewable facilities, the Federal Government's Renewable Energy Target, increased penetration of DPV, increasing pressure to reduce greenhouse gas emissions and consumers' demand for green products. At the same time, other generation technologies, such as battery storage, are becoming more viable and new sources of dispatchable capacity, such as virtual power plants, are being trialled for future use.

Some of these resources could flatten the demand profile and delay the need for additional conventional capacity to address system stress events, while others may cause new types of system stress events in the future.

Given the changes to the nature of the demand profile and generation in the SWIS since the RCM was implemented, and the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation, the Coordinator and the MAC were concerned that the current RCM design may no longer be fit for purpose.

1.1.3 Scope of the RCM Review

The Coordinator, in consultation with the MAC, set the following conditions for the RCM Review:

- the WEM will continue to have an RCM;
- the purpose of the RCM is to ensure acceptable reliability of electricity supply at the most efficient cost; and
- any changes to the RCM should not erode the level of system reliability currently provided for by the WEM Rules.

The objective of the review is to develop an RCM that:

- achieves the system reliability that underpins the current RCM at the most efficient cost for consumers for the current and the anticipated future system demand profiles;
- addresses any reliability issues associated with the transformation of the energy sector; and
- accounts for any transitional issues associated with any changes to the RCM.

The following aspects related to the RCM are out of scope of the review:

- the Network Access Quantity (NAQ) regime;
- the Reserve Capacity Price (RCP) regime; and
- Energy Price Limits.[3]

The review is being conducted in three stages:

- Stage one focussed on the definition of reliability and the characteristics of the capacity needed in future years, including the Planning Criterion, the methods for assigning Certified Reserve Capacity (CRC)[4] and the Benchmark Reserve Capacity Price (BRCP).
- Stage two will assess how the outcomes of stage one affect the operation of other parts of the RCM, including outage scheduling, the refunds mechanism and the Individual Reserve Capacity Requirements (IRCR).
- Stage three will deliver the detailed design and any transitional arrangements.

The MAC has established the RCM Review Working Group (RCMRWG) to support the Coordinator's work. More information on the review is available from the EPWA website[5], including the Scope of Works for the RCM Review, the Terms of Reference for the RCMRWG, papers for RCMRWG and MAC meetings and detailed minutes for each meeting. An updated timetable for the review stages is included in Appendix A.

3 The Coordinator is currently reviewing the Energy Price Limits, in parallel with the RCM Review, as part of his market power mitigation strategy. Energy Policy WA is ensuring that both work streams are consistent.

4 Alternative methods for assigning CRC have been identified in stage one of the RCM Review and will be assessed in stage two.

5 https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group

1.2 Purpose of this paper

This consultation paper sets out the findings and recommendations arising from stage 1 of the RCM Review and presents proposals for changes to the design of the:

- Planning Criterion;
- RCM products;
- BRCP; and
- capacity certification process.

The remainder of this paper is structured as follows:

- Chapter 2 describes the purpose of the RCM, focusing on the types of system stress expected in the SWIS in 2030 and in 2050;
- Chapter 3 discusses the Planning Criterion;
- Chapter 4 sets out considerations for the BRCP;
- Chapter 5 covers the capacity certification process, including the different capacity classes;
- Appendix A sets out the expected timetable for the review;
- Appendix B provides more information on the approach to the system stress modelling;
- Appendix C provides estimated Capacity Credit allocations if 'unforced capacity' (UCAP) arrangements were to be implemented; and
- Appendix D provides more information on the approach to the economic modelling.

In parallel with this paper, EPWA is publishing a paper on the review of international capacity mechanisms conducted by Robinson Bowmaker Paul (RBP) as part of the RCM Review (Reserve Capacity Mechanism Review (www.wa.gov.au)).

1.3 Call for submissions

Stakeholder feedback is invited on the proposed changes to the RCM, as outlined in this consultation paper. Submissions can be emailed to energymarkets@dmirs.wa.gov.au. Any submissions received will be published on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00pm (WST) on Tuesday, 27 September 2022. Late submissions may not be considered.

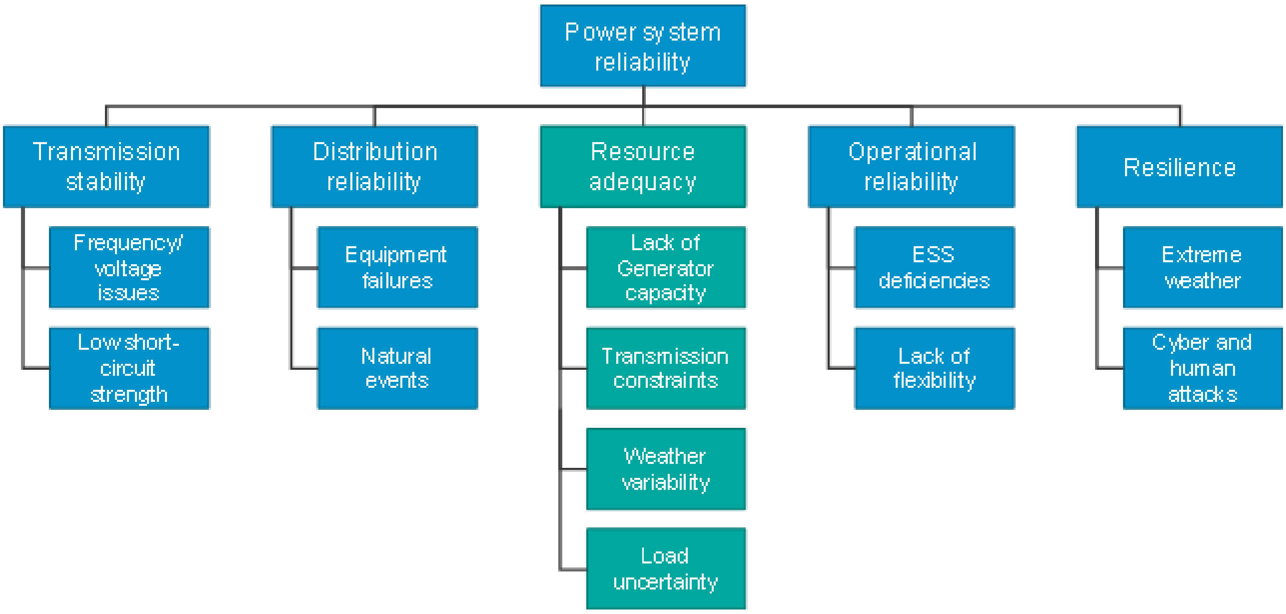
2. How has the RCM Review been conducted

2.1 Resource adequacy and operational reliability

The purpose of the RCM is to ensure that the SWIS has adequate capacity available to maintain a defined level of reliability at the most efficient cost. Under the objectives of the RCM Review, any changes to the RCM must not erode the level of system reliability currently provided for by the WEM Rules.[6]

Power system reliability is the overall ability of the power system to meet demand for electricity within given standards. Various factors contribute to the level of reliability delivered to customers connected to a particular power system, as shown in Figure 2.[7]

Figure 2: Elements of Power System Reliability



Capacity markets worldwide have been designed to address the issue of resource adequacy – ensuring there will be sufficient generation available to dispatch most or all of the time to meet system demand. The specific design features are driven by:

- the quantity of available capacity;
- the location of available capacity;
- the availability of fuel for that capacity (including wind and sunshine); and
- the quantity, shape, and uncertainty of expected load.

Capacity mechanisms that consider these elements have historically delivered a generation fleet sufficient to allow the power system operator to schedule and dispatch available capacity to deliver reliable *and* secure[8] electricity supply. The system operator may need to dispatch some facilities in preference to others while ensuring that there is sufficient capability in the fleet to meet the load and provide Essential System Services (ESS).

6 See section 3.1.4 for analysis of economic efficiency.

7 Adapted from Energy Systems Information Group, Redefining Resource Adequacy for Modern Power Systems, 2021.

8 Power system security is the ability of the power system to withstand disturbances, including fluctuations or outages to generation, network components, or load.

The increasing volatility of load and the changing nature of the generation fleet mean that this will no longer necessarily be the case. If a capacity mechanism does not incentivise capacity that can provide ESS and move nimbly to follow changes in load, that type of capacity may not enter the market, and therefore, may not be available for real-time dispatch.

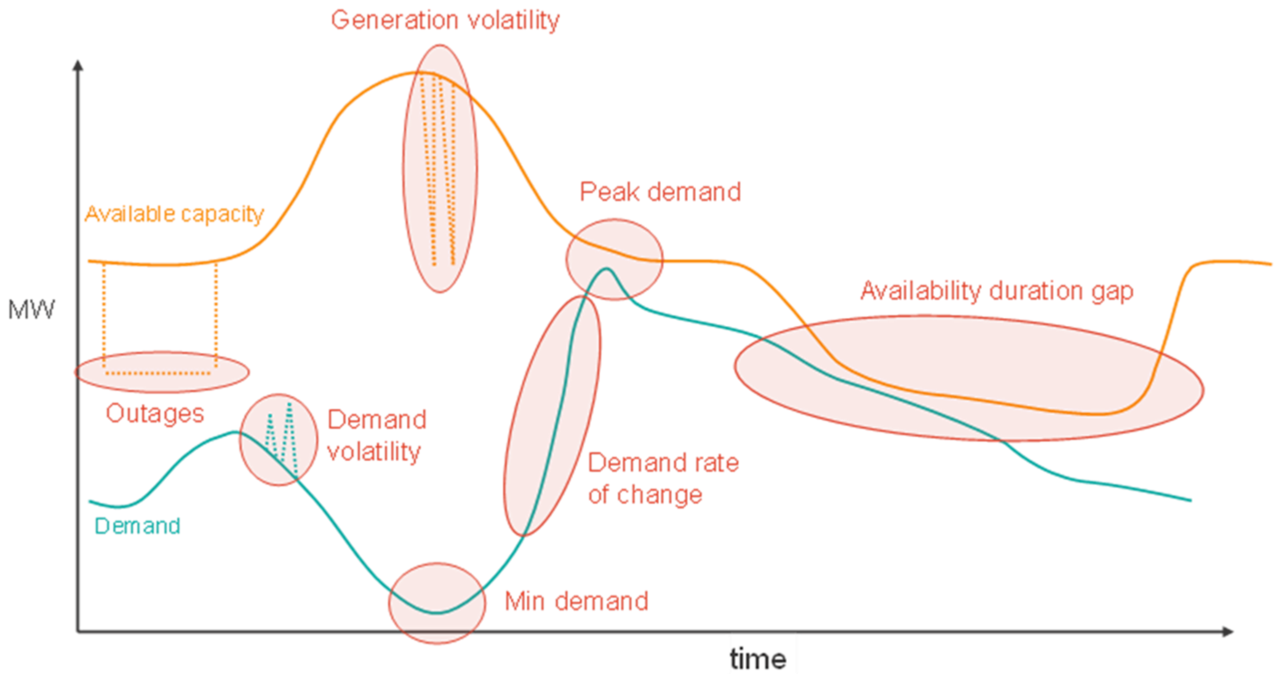
The RCM is meant to help to ensure that, during real time dispatch, a fleet of capacity resources is available to be dispatched to meet demand when needed. Reliability will be affected if there is not sufficient capacity in real time, or if that capacity cannot be operated in a way that meets the requirements at the time.

The RCM therefore has a bearing on aspects of operational reliability and needs to ensure that capacity with the necessary capabilities will be available in operational time frames.

2.2 How is system stress changing and what does that mean for the RCM design

The SWIS faces a variety of challenges, as shown in Figure 3.

Figure 3: Sources of System Stress



The RCM is currently designed to address system conditions when system margins (i.e. the difference between supply and demand) are low. In the WEM, this normally occurs during hot summer periods where air conditioners are working hard. With increasing volumes of intermittent generation on the system – especially residential solar – and the projected mass uptake of electric vehicles, other kinds of system stress that have the potential to affect system reliability have been identified, including:

- decreasing minimum demand, which occurs in the middle of the day when DPV generation is injecting at its maximum, and threatens the stability of the power system;
- the rate of change in demand, which is increasing due to the significant difference between the mid-day low and the evening peak;
- generation volatility, which is caused by a drop-off in wind or clouds covering the sun, and affects multiple facilities at the same time;

- planned and unplanned outages, which reduce the capacity that is available, sometimes with no warning; and
- the availability duration gap, where demand is lower than the peak, but limitations on facility availability or energy output mean that the system risks unserved energy.

Three key questions were asked when considering whether the identified system stress events should be addressed through the RCM:

1. is the system stress caused by actions that will realistically remain uncontrolled in future;
2. does capacity with the ability to address the stress event need substantial capital expenditure with multi-year lead times; and
3. are there adequate price signals outside the RCM to provide incentive for facilities to address that stress event?

2.2.1 Modelling approach

The first step in the RCM Review was to consider the types of system stress events that the SWIS will face between now and 2050. The goal was to:

- characterise system stress in the SWIS;
- model how the current and future fleet contributes to or mitigates the stress under various retirement and build scenarios; and
- identify potential deficiencies in the existing capacity product and Planning Criterion.

Modelling was conducted to quantify system stress due to:

- maximum demand, including extreme peaks;
- minimum demand, including extreme lows;
- demand variation, including the speed and magnitude of change; and
- generation volatility, including the impact of rapid changes in output from intermittent generation.

The system stress model takes a given generation fleet, demand profile, and intermittent generation trace for each facility, and simulates forced outages based on historical outage rates (including mean time to repair). New capacity is added until the total quantity of unserved energy matches the target of 0.002% set in the Planning Criterion.

Several different fleet development scenarios were considered, to explore potential for different futures, as shown in Table 2.

Table 2: Fleet Scenarios for 2050

Scenario	Variable Renewables	Flexibility Resource
1	Sufficient PV + wind by 2050 to meet energy requirement	• Large firming capability • Some demand flexibility
2	PV + Wind overbuild by 2050 reducing amount of firming capability required	• Less firming capability • Large demand flexibility

Scenario	Variable Renewables	Flexibility Resource
3	Sufficient PV + wind by 2050 to meet energy requirement	• Green thermal • Some firming capability • Some demand flexibility

These fleet scenarios were then simulated in an economic dispatch model, to consider the effects of different levels of CRC and BRCP on facility build and retirement incentives. This modelling will continue to be refined in stage two of the RCM Review as the design proposals are developed.

More information on the modelling approach (for both types of modelling) is included in Appendix B, and results from the economic dispatch modelling are included in Appendix D.

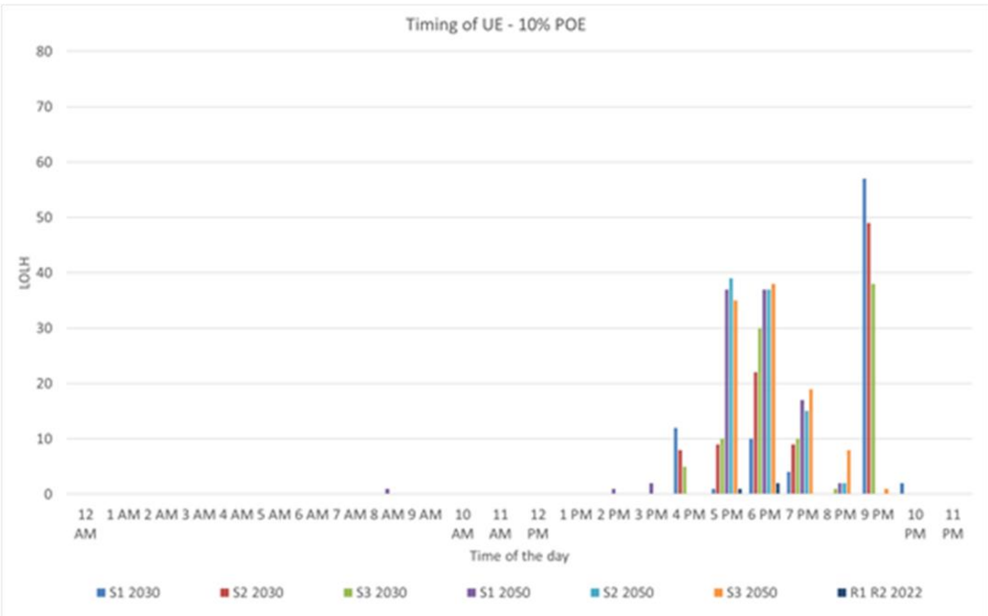
2.2.2 Analysis

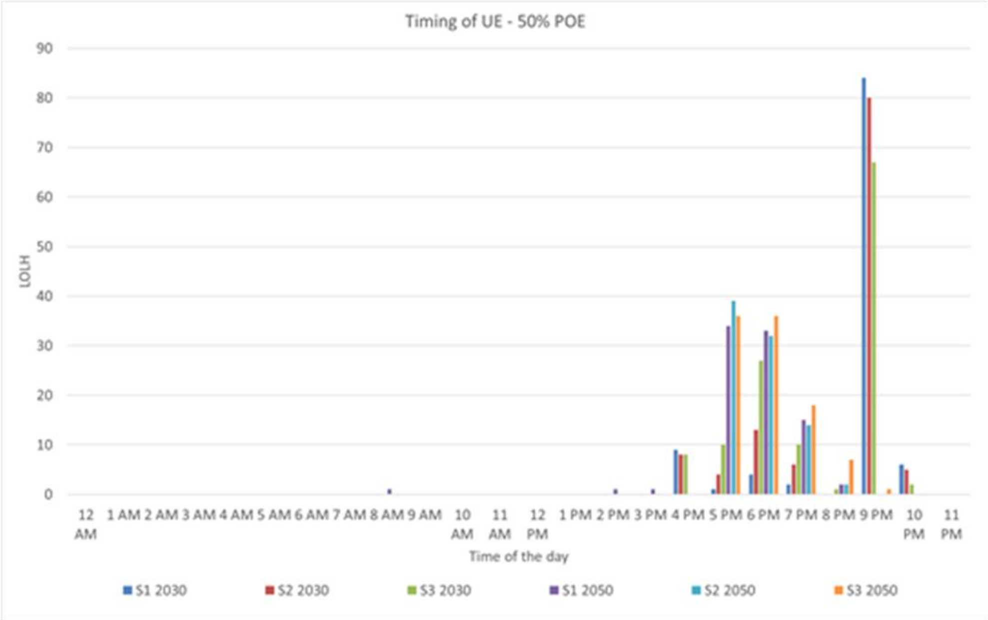
Maximum demand

The current RCM is designed to ensure there is sufficient capacity to meet maximum demand in a one-in-ten-years peak event. The modelling indicates that this maximum demand period is expected to continue to move later in the day, and to flatten and extend later into the evening by 2050.

While there is potential for unserved energy in non-peak periods, the peak periods are expected to continue to have the highest likelihood of unserved energy. Figure 4 shows the number of hours of unserved energy at each time of day, highlighting that the evening peak remains the period with highest likelihood of unserved energy, confirming the need for the RCM to continue to provide for this system stress.

Figure 4: Timing of Unserved Energy (UE) events (Top: 10% POE, Bottom: 50% POE)

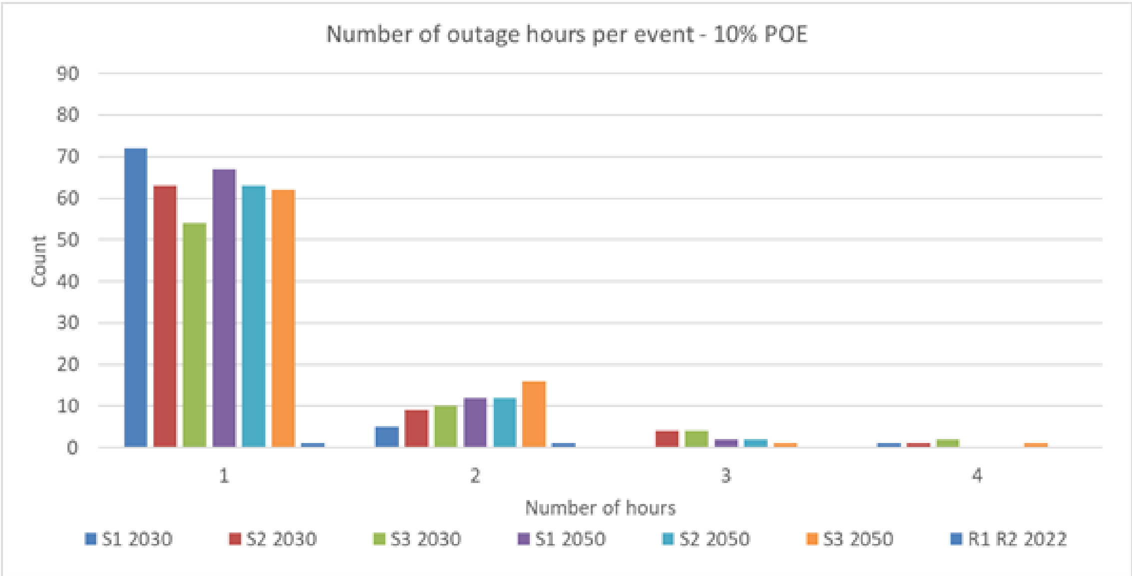


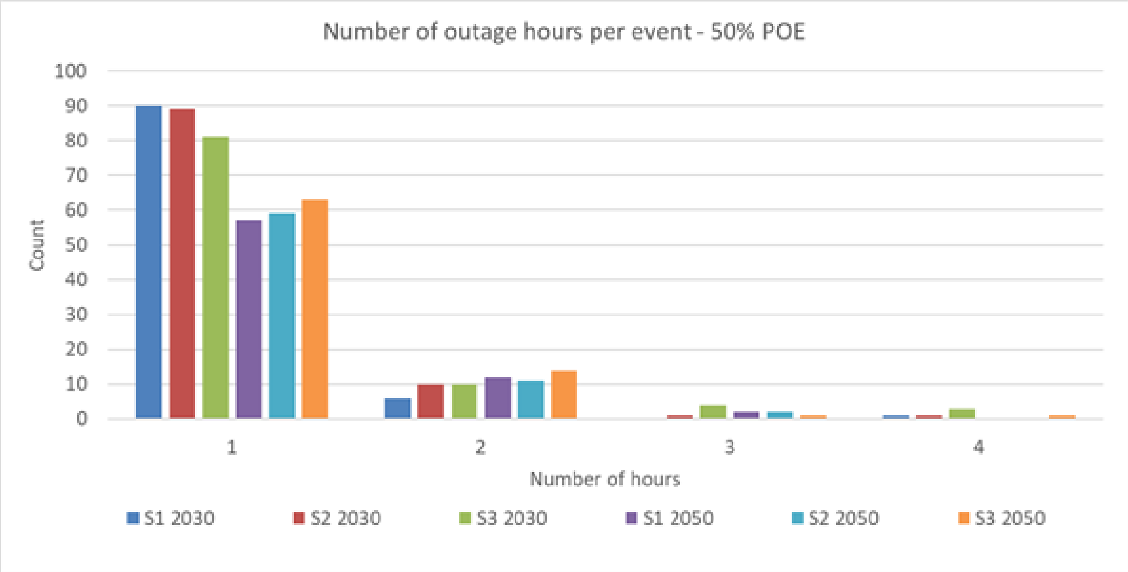


The spike in unserved energy events at 9:00 pm in the 2030 scenarios is due to storage availability hours being set to 4:30 pm to 8:30 pm. Storage availability has been extended to 7:00 am for the 2050 scenarios. Section 5.2 discusses proposals for managing this growing 'duration gap'.

Although facility forced outages can take a long time to fix and restore, the outages suffered by consumers are mostly only one or two hours in duration, but are up to four hours in a few cases in some scenarios. Figure 5 shows the count of customer outage events lasting one, two, three and four hours.

Figure 5: Number of customer outage hours per event (Top: 10% POE, Bottom: 50% POE)





Providing sufficient capacity to meet forecast demand (both peak and overall energy) must remain a core function of the RCM (and does not preclude the RCM from also dealing with other stress events):

1. Demand will be caused by actions that will realistically remain uncontrolled in future. Most end-users are expected to continue to withdraw whatever quantity of energy they want and whenever they want it.
2. Capacity with the ability to serve demand will require capital expenditure with multi-year lead times. While paid demand reduction can be sourced relatively quickly, delivering new energy supply capability will still require years of planning and construction.
3. Facilities will not provide services without a price signal, either from the energy or ESS markets or from the RCM. Investors will not build facilities if they cannot see a way to earn a return on their assets. While some facilities can earn a return from the energy markets alone, current requirements for SWIS reliability will require facilities that are seldom dispatched in the energy markets.

Conceptual Design Proposal 1 (retain the current approach):

Retain the existing 'peak capacity' product to provide an explicit price signal several years ahead of the need for new capacity to meet peak demand and overall energy demand.

Consultation Questions:

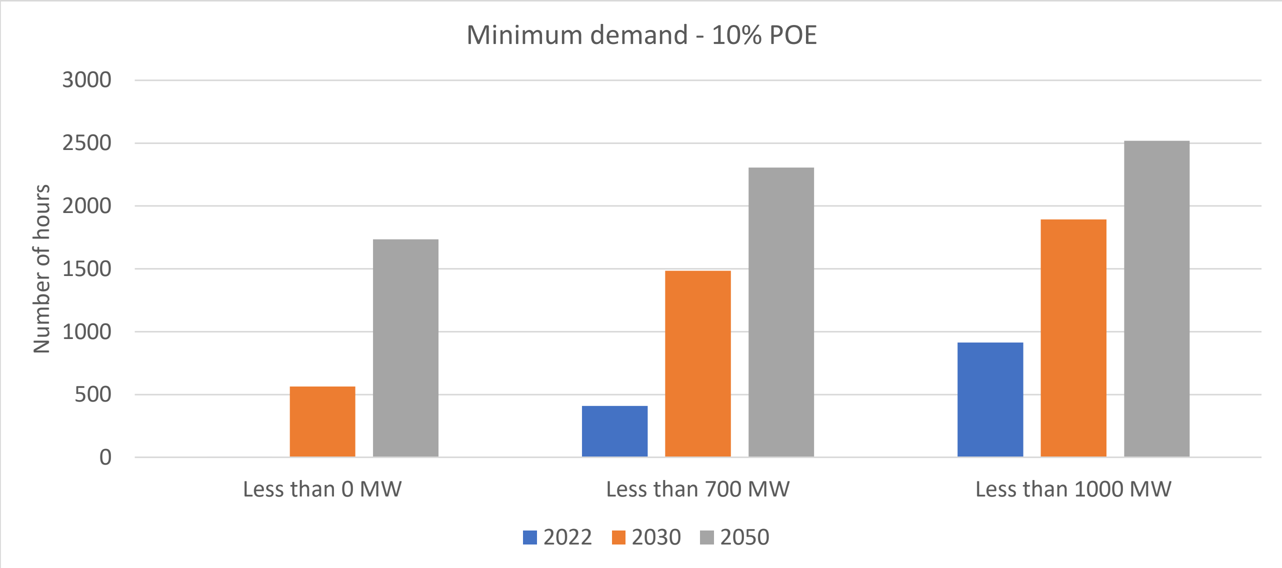
(1) Do stakeholders support the retention of the existing peak capacity product?

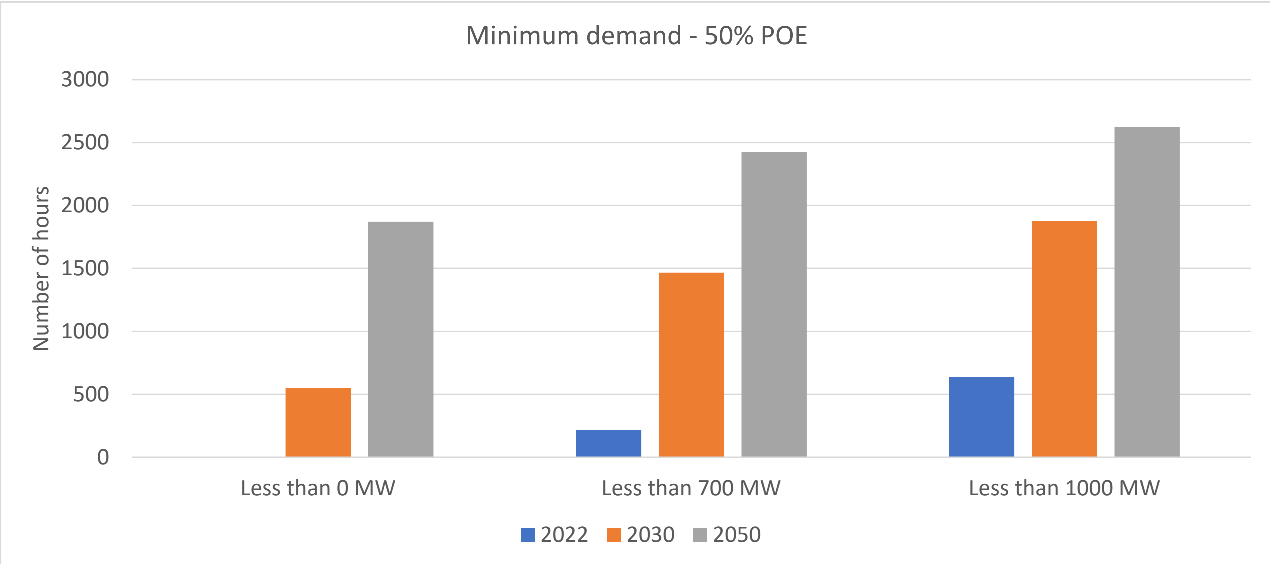
Minimum demand

The modelling indicates that the low demand period in the middle of the day will continue to deepen.

Operational load will be negative in some intervals by 2030, and will be less than 700 MW for 2400 hours per year (27% of all periods) by 2050, as shown in Figure 6.

Figure 6: Depth of minimum operational load (Top: 10% POE, Bottom: 50% POE)





A key consideration is whether the future RCM should include a signal for developers to build facilities capable of responding to low load situations, by increasing withdrawal or reducing injection when needed. Based on the system stress modelling results, such a service could be needed for more than 2200 hours per year (25% of periods) by 2050.

It is considered that:

1. Arrangements for end-user injection management and flexibility are being addressed through the Distributed Energy Resources (DER) Roadmap.[9]
2. Facilities capable of helping to manage minimum demand are unlikely to require large capital expenditure with multi-year lead times. Over the coming years, DER Roadmap activities will support the aggregation of DER into virtual power plants which can be included in energy and

[9] Information about the DER Roadmap can be found here: https://www.wa.gov.au/government/distributed-energy-resources-roadmap

ESS dispatch. As a backstop, the recently introduced Emergency Solar Management, the emergency curtailment service for DPV, can be triggered at very short notice.

3. Registered facilities and large customers/retailers in the WEM receive price signals in the form of very low or negative real-time energy market prices. Facilities with the capability to deliver curtailed injection are likely to exist regardless of an explicit long-term price signal and can be incentivised to deliver this via the energy market price signals.

Load increase and curtailed injection can therefore be dealt with as an operational matter through real-time market mechanisms (energy and ESS) providing pricing signals, and do not need to be explicitly incorporated into the RCM. This view was supported by the MAC.

This position may need to be re-confirmed at the completion of the next stage of the RCM Review. It is important that the RCM does not provide perverse incentives that exacerbate the minimum load risks. It will be particularly important to ensure that new facilities are flexible over a large range of their nameplate capacity, dis-incentivising high levels of minimum generation and long start-up, minimum running, or minimum restart times.

Conceptual Design Proposal 2 (retain the current approach):

- The RCM will not include a specific product to manage minimum demand.
- The RCM design and the capacity certification process will seek to avoid incentives for new facilities that could make minimum demand more difficult to manage, such as facilities with high minimum stable generation, and/or long start-up, minimum running or minimum restart times.

Consultation Questions:

(2) Do stakeholders support not including a product in the RCM to manage minimum demand?

Demand rate of change

The modelling indicates that:

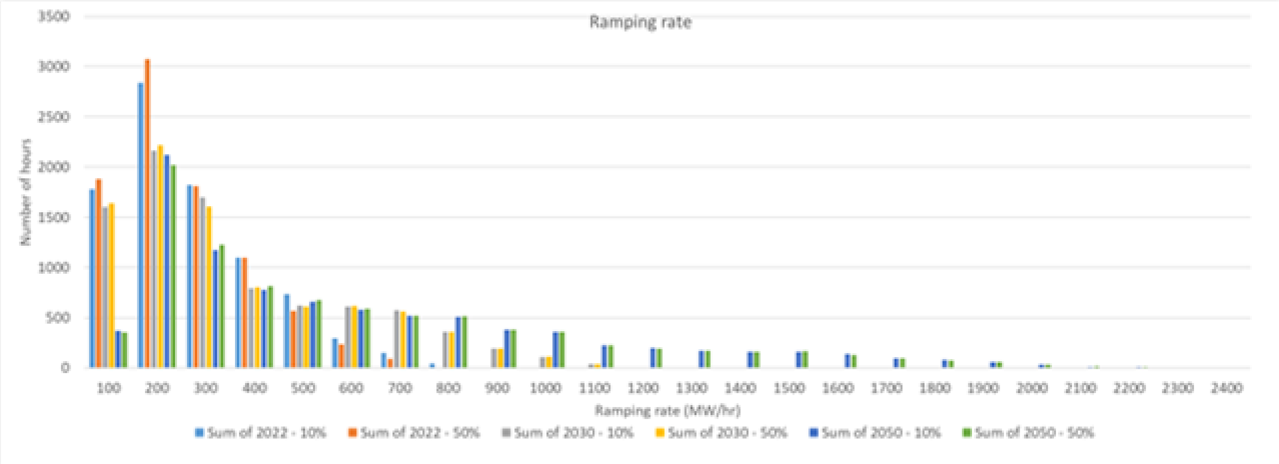
- increasing maximum demand and decreasing minimum demand combine to increase the rate at which operational load changes from the middle of the day through to the evening peak; and
- the magnitude of the difference between the low and high points increases over time, as does the overall ramp rate needed from the available fleet.

This is further explained in Appendix B.2 of this consultation paper.

There is a similar issue in the morning, where the fleet must ramp down as DPV generation comes on, but this is not as large as the afternoon requirement.

Figure 7 shows the number of hours in each year in which ramp rates are expected to be at a particular level. The highest ramp rate required is around 800 MW per hour in 2022, close to 1100 MW per hour by 2030 and close to 2400 MW per hour by 2050. This means that the WEM will increasingly need very flexible generation that can start, ramp up and down, and stop quickly.

Figure 7: Future Ramp Rates



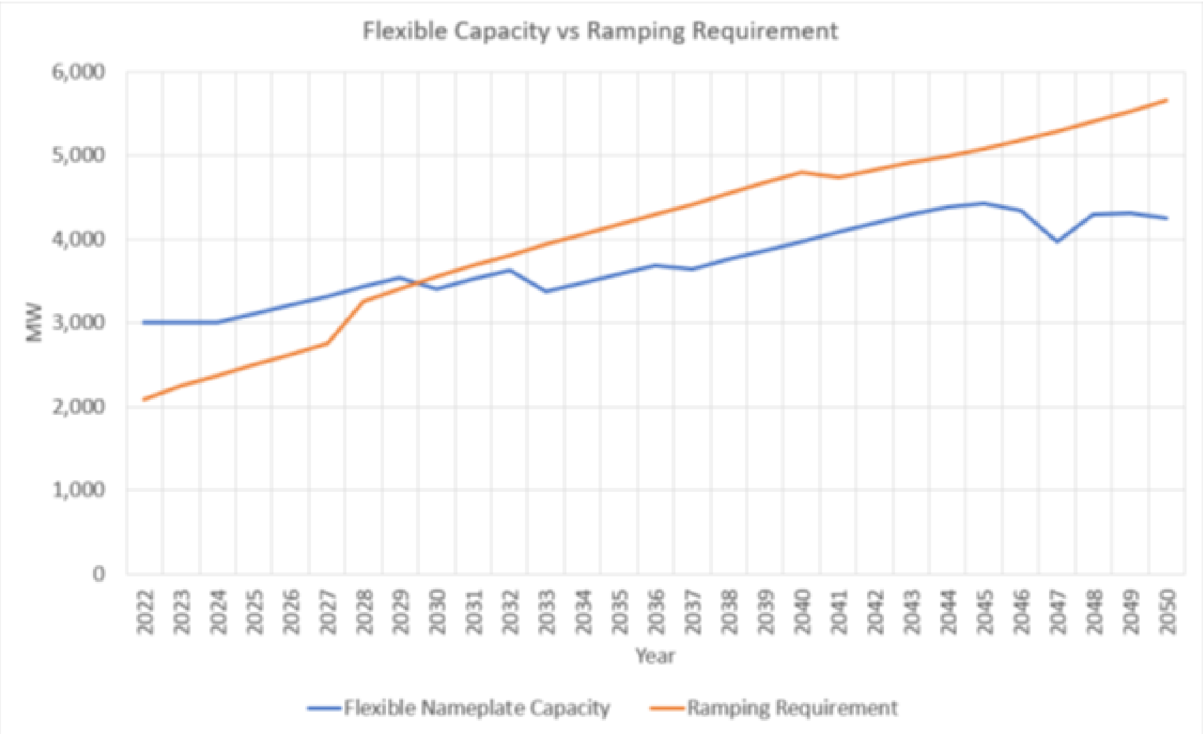
The modelling indicates that the SWIS will see ramp rates in excess of 2 GW/hour by 2050. This is well within the capabilities of current technologies (e.g. open cycle gas turbines (OCGTs) and batteries), as long as sufficient capacity of such technologies is available.

However, new OCGTs are unlikely to be an option in the zero carbon future.

Figure 8 compares:

- the expected total MW of fast ramping needed, based on the steepest afternoon ramp in the whole year; and
- the expected total MW of firm flexible capacity built under the fleet build scenarios used for system stress modelling.

Figure 8: Flexible capacity needed for energy shifting vs ramping requirement



From the late 2020s, the fast-ramping capacity required in these fleet development scenarios exceeds the available flexible capacity.

Therefore an explicit long-term price signal is needed to ensure that sufficient fast-ramping capacity is available:

1. While EPWA's DER Roadmap work is seeking to increase the ability of flexible distributed resources to access market revenue streams, it is likely that much demand will continue to be controlled by end-users, and will not ramp in a controlled fashion. The WEM needs to continue to serve the load, whatever that is.
2. Fast-ramping capability requires significant capital expenditure with multi-year lead times. Commissioning either a transmission-connected facility or a large quantity of distributed storage for aggregation is a slow process and will require significant capital expenditure.
3. The existing capacity product will encourage new entry, but that entry may not be able to provide sufficient fast ramping capability.

Conceptual Design Proposal 3:

Introduce a new capacity product into the RCM (alongside the existing peak capacity product) to incentivise flexible capacity that can start, ramp up and down, and stop quickly.

Consultation Questions:

(3) Do stakeholders support inserting a new flexible capacity product in the design of the RCM?

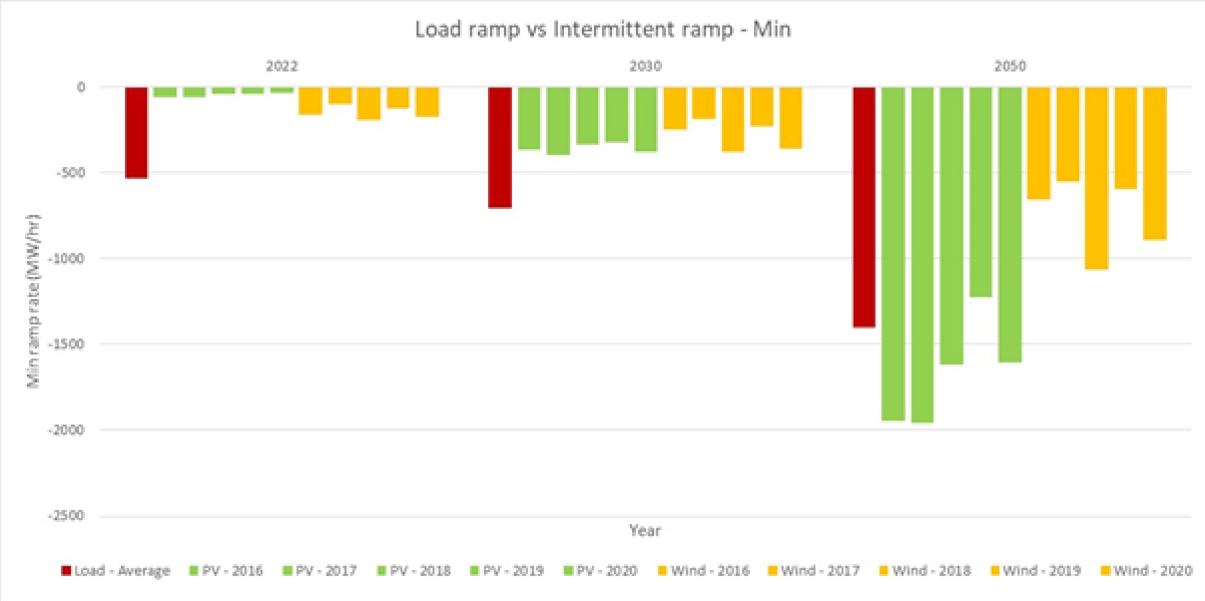
Generation and demand volatility

As discussed above, the modelling indicates increasing maximum demand and decreasing minimum load due to a higher penetration of distributed generation, which causes an increase in the overall ramp rate required from the resources fleet. However, operational demand is not the only potential source of flexibility requirements: the fleet must have sufficient flexible capacity to address potential variability in wind and solar output.

Figure 9 shows the maximum expected variability of solar and wind facilities (green and yellow bars), compared to the upward/downward ramp required to meet underlying operational load (red bars) for 2022, 2030 and 2050.

The maximum hourly solar and wind ramping estimates are based on the historical generation profiles of intermittent facilities in each year from 2016 to 2020, with the volume scaled up to account for additional installed capacity in 2030 and 2050. The maximum hourly operational load ramp rate is based on the ramping analysis discussed above.

Figure 9: Downward ramp rate comparison



Where the red bar is taller than the green and yellow bars, the maximum hourly operational load ramp rate is higher than the maximum hourly intermittent generation output. This shows that, in 2022 and 2030, if the fleet has sufficient flexible capacity to meet the maximum expected hourly operational load ramp, it will also have sufficient flexible capacity to manage intermittent generation volatility.

If solar generation penetration increases as modelled in 2050, the upward and downward ramp rate of grid connected PV could, at times, be greater than the ramp of underlying demand. However, this maximum solar ramping is not due to underlying variability in solar output, but rather reflects the regular daily profile of solar generation, with the large changes only occurring at sunrise and sunset.

EPWA considers that these regular and predictable periods of high ramp rates can be managed through market processes to spread the change over time, and it should not be necessary to build specific capacity to respond over and above the quantity required to manage changes in operational load. This means that the RCM does not need to address this issue directly, because volatility in operational load and intermittent generation output over short timeframes can continue to be managed through ESS.

Conceptual Design Proposal 4:

It is not proposed that the Planning Criterion includes reference to volatility in the output of intermittent facilities.

Volatility in operational load and intermittent generation over short timeframes can be managed through ESS and re-dispatch. The addition of the flexible capacity product, proposed under the Conceptual Design Proposal 3, is expected to provide adequate capacity that is capable of providing these services.

Consultation Questions:

(4) Do stakeholders support not amending the Planning Criterion to include consideration of the volatility of intermittent generators?

3. Review of the Planning Criterion

The Planning Criterion is a key component of the RCM, as it drives the Reserve Capacity Requirement and the quantity of reserve capacity to be procured.

3.1 Planning Criterion for system adequacy

3.1.1 Measures for system adequacy

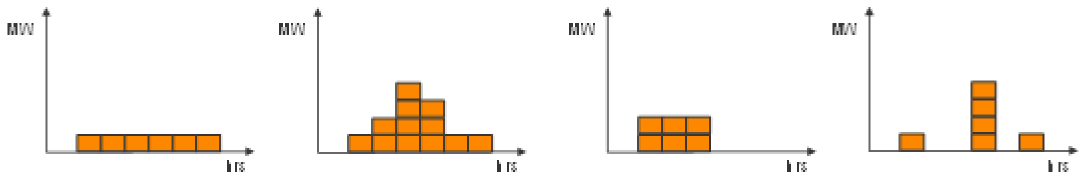
Power system reliability can be measured in several different ways, each describing a different aspect of the impact of disruptions on consumer supply:

- Expected Unserved Energy (EUE) is the total MWh of energy desired by customers, but not delivered;
- Loss of Load Events (LOLEv) is the number of outage events in which customers were not supplied; and
- Loss of Load Hours (LOLH) is the number of hours in which customers were not supplied.

None of these metrics alone fully describes the reliability delivered to customers. EUE shows the total shortfall over a period but does not account for the number or duration of events, LOLEv records the number of events but does not account for the depth or duration, and LOLH records the total duration of outage but does not account for the depth or number.

The various metrics can produce very different results for the same events, or the same results for very different events, as shown in Figure 10.[10]

Figure 10: Reliability metrics for different outages



EUE	6	12	6	6
LOLEv	1	1	1	3
LOLH	6	6	3	3

The first two events have the same LOLEv and LOLH but different EUE, and the second two events have the same EUE and LOLH but different LOLEv.

The different kinds of shortfall events are best served by different technology mixes. For example, storage resources can assist in all types of events, but more stored energy would be needed to deal with event one than event four, which in turn would require more stored energy than events two and three.

A future proofed reliability criterion must account for the metrics which are important for the power system at hand.

10 Chart adapted from https://www.esig.energy/resource-adequacy-for-modern-power-systems/.

3.1.2 The current Planning Criterion

The current WEM Planning Criterion in clause 4.5.9 of the WEM Rules is as follows:

4.5.9 The Planning Criterion to be used by AEMO in undertaking a Long Term PASA study is that there should be sufficient available capacity in each Capacity Year during the Long Term PASA Study Horizon to:

(a) meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:

i. 7.6% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and

ii. the maximum capacity, measured at 41ºC, of the largest generating unit;

while maintaining the SWIS frequency in accordance with the Normal Operating Frequency Band and the Normal Operating Frequency Excursion Band. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten; and

(b) limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses and taking into account transmission network capabilities including constraints).

This two-limbed criterion is unusual internationally, as the Planning Criterion (also known as the reliability criterion) in other markets is set using a single limb, based on the number of LOLEv, the number of LOLH or the expected quantity of EUE.[11]

Other jurisdictions are looking at moving to a multi-limbed criterion, like the WEM's, because future fleet characteristics mean that their contribution to reliability at times other than peak is also important. The recent National Energy Market (NEM) Reliability Panel draft reliability standard and settings report[12] committed to further work on another limb for the NEM reliability criterion.

The review of international capacity mechanisms shows that a single-limb criterion risks missing some aspects of reliability in the future, and it remains appropriate to retain a two limbed Planning Criterion in the WEM, similar to the current Planning Criterion.

EUE is the most nuanced measure of reliability. This measure represents the total MWh of unserved energy and is limb (b) of the current Planning Criterion. The specific percentage of EUE to target is addressed in section 3.1.4.

The current limb (a) – the 10% probability of exceedance (POE) peak measure – also remains appropriate. Using a LOLEv count would be more appropriate if the modelling showed infrequent long and deep outages but, as shown in Figure 5, the modelling indicates that with the flattening of the peak, potential LOLEv are likely to be short and shallow.

Retaining the two current limbs of Planning Criterion was supported by the MAC.

11 For more information, see the international review paper published alongside this consultation paper.

12 https://www.aemc.gov.au/market-reviews-advice/2022-reliability-standard-and-settings-review

Conceptual Design Proposal 5:

The two current limbs of Planning Criterion will be retained, requiring sufficient capacity to:

- meet the 10% POE demand, and
- achieve EUE no greater than a specified percentage of expected demand.

Consultation Questions:

(5) Do stakeholders support retention of the current two limbs of the Planning Criterion?

3.1.3 The reserve margin in the Planning Criterion

As noted above, limb (a) of the current Planning Criterion includes a reserve margin to account for outages coincidental with peak load, considering the quantity of expected forced outages, and the required amount of spinning reserve (also known as Contingency Reserve Raise).

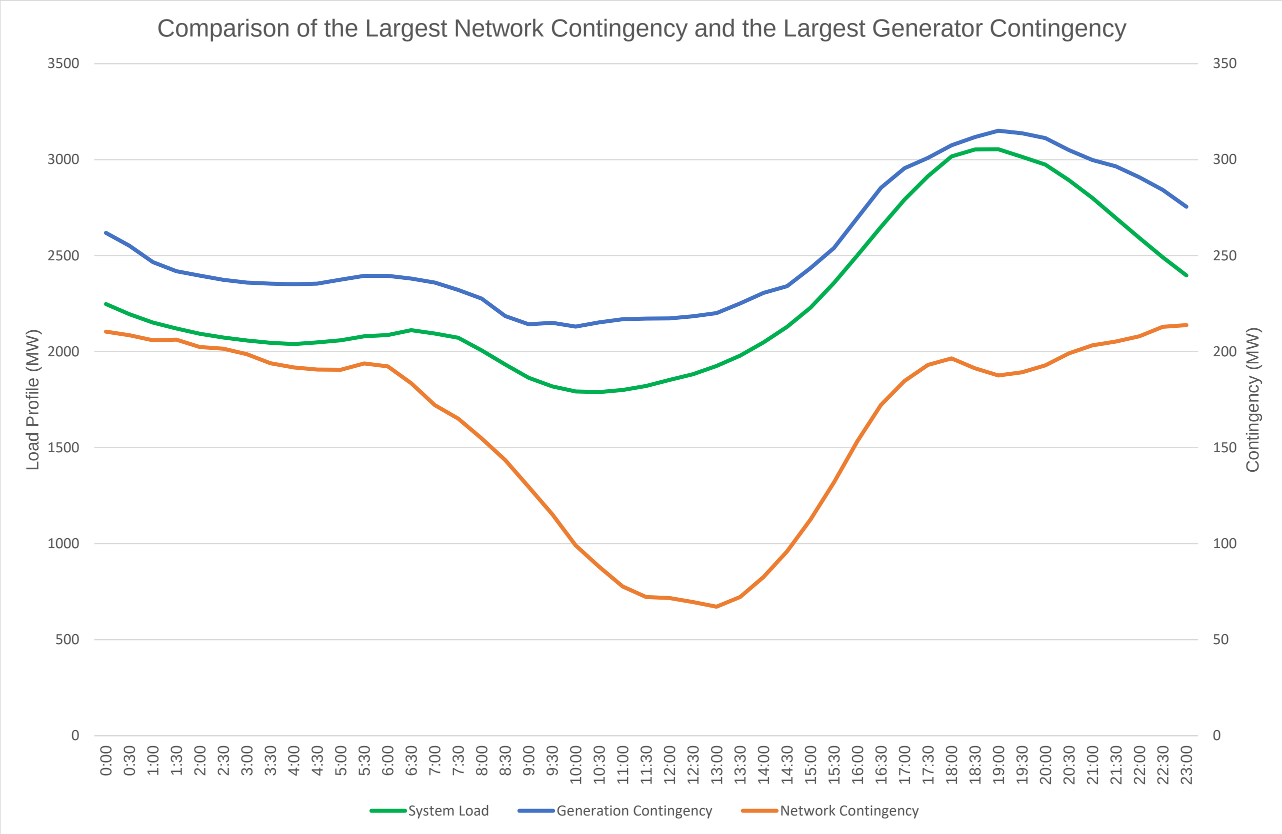
Sub-clause (i) accounts for the use of an installed capacity (ICAP) based CRC method, reflecting the cost and benefit of additional capacity considering the expected quantity of forced outages of the fleet of capacity resources. Sub-clause (i) would not be needed at all under an unforced capacity (UCAP) approach to CRC allocation (see section 5.3 for more information regarding the use of ICAP or UCAP). Because the fleet of capacity resources and the quantity of expected forced outages changes from year to year, it is considered that this limb could be improved by replacing the hardcoded percentage with a methodology to determine the percentage for each capacity cycle as the expected forced outage rate at the time of system peak.

Sub-clause (ii) reflects the need to maintain sufficient capacity if the largest contingency occurs at the time of system peak, by ensuring that the reserve capacity target includes an allowance for spinning reserve. Sub-clause (ii), as written, may no longer accurately capture the largest contingency on the SWIS during system peak, as the spinning reserve requirement can be set by a network contingency in the future, which can be larger than the largest generator. The relevant network contingency may change depending on the location and capacity of new facilities (including network facilities).

At the MAC meeting on 23 August 2022, AEMO indicated that it has not yet observed the largest network contingency exceeding the largest generation contingency during system peak. However, with the announced retirement of the Collie generation plant in the late 2020s this may become more likely.

Figure 11shows the current trend of the largest network contingency and largest generator contingency over the load profile.

Figure 11: Comparison of the Largest Network Contingency and the Largest Generator Contingency



Source: Australian Energy Market Operator

Figure 11 shows that the proposed change to the Planning Criterion should not lead to an immediate increase in the Reserve Capacity Target, but that it will probably start binding as large generating units retire and more generation is installed in network constrained locations.

Unless sub-clause (ii) is changed before the next reserve capacity cycle, the Reserve Capacity Target may be set at an insufficient level to ensure that there will be enough capacity in the event the largest contingency occurs at the same time as peak demand.

EPWA proposes to amend sub-clause (ii) before the next Reserve Capacity Target is set, as follows, with other amendments resulting from the RCM Review to follow later:

4.5.9 The Planning Criterion to be used by AEMO in undertaking a Long Term PASA study is that there should be sufficient available capacity in each Capacity Year during the Long Term PASA Study Horizon to:

(a) meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:

i. ~~7.6% of~~ the forecast peak demand (including transmission losses and allowing for Intermittent Loads) multiplied by the proportion of capacity expected to be unavailable at the time of peak demand based on historical facility forced outage rates; and

ii. the size, in MW, of the largest contingency relating to loss of supply (related to any Facility, including a Network) expected at the time of forecast peak demand (including transmission losses and allowing for Intermittent Loads) ~~maximum capacity, measured at 41ºC, of the largest generating unit~~;

~~while maintaining the SWIS frequency in accordance with the Normal Operating Frequency Band and the Normal Operating Frequency Excursion Band.~~ The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten; and

(b) limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses and taking into account transmission network capabilities including constraints).

This proposal was supported by the MAC.

It is acknowledged that, if the largest network contingency increases significantly, the capacity requirement could also increase, placing upward pressure on the overall capacity cost. EPWA notes that, under the WEM Rules, Western Power is required to consider market impacts in its transmission network planning.

Conceptual Design Proposal 6:

Amend the reserve margin so that:

- sub-clause 4.5.9(a)(i) uses the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to forced outage, rather than a hardcoded percentage; and
- sub-clause 4.5.9(a)(ii) refers to the largest contingency on the power system, rather than the largest generating unit.

Introduce the proposed amendment to clause 4.5.9(a)(ii) to change the determination of the largest contingency for the calculation of the reserve margin, in time for the 2023 Reserve Capacity Cycle (for the Capacity Year starting on 1 October 2025).

Consultation Questions:

(6)(a) Do stakeholders support amending the reserve margin as indicated in Conceptual Design Proposal 6?

(6)(b) Do stakeholders have any concerns about the proposed amendments to clause 4.5.9(a)(ii)?

(6)(c) Do stakeholders support commencing the proposed amendments to clause 4.5.9(a)(ii) for the 2023 Reserve Capacity Cycle?

3.1.4 Assessment of unserved energy

Maintaining the same level of reliability as the system was intended to achieve under the WEM Rules requires keeping the peak load requirement at the current 10% POE level. Limb (a) of the Planning Criterion currently dominates limb (b), which limits the EUE to 0.002% of total demand.

To determine an appropriate metric for the EUE in limb (b) of the Planning Criterion, the trade-off needs to be explored between higher reliability requirements and cost, balancing the cost of unserved energy with the cost of new reserve capacity.

Resource adequacy modelling was used to find the EUE percentage at which the cost of unserved energy plus the cost of new capacity was at a minimum. This exercise used the fleet composition scenarios described in section 2.2.1, and price scenarios to consider a range of BRCPs, assuming that there is no surplus capacity (which is the assumption for setting the EUE target). The value of unserved energy ($48.10/kWh) is taken from Western Power's work on the Value of Customer Reliability (VCR) for the SWIS.[13]

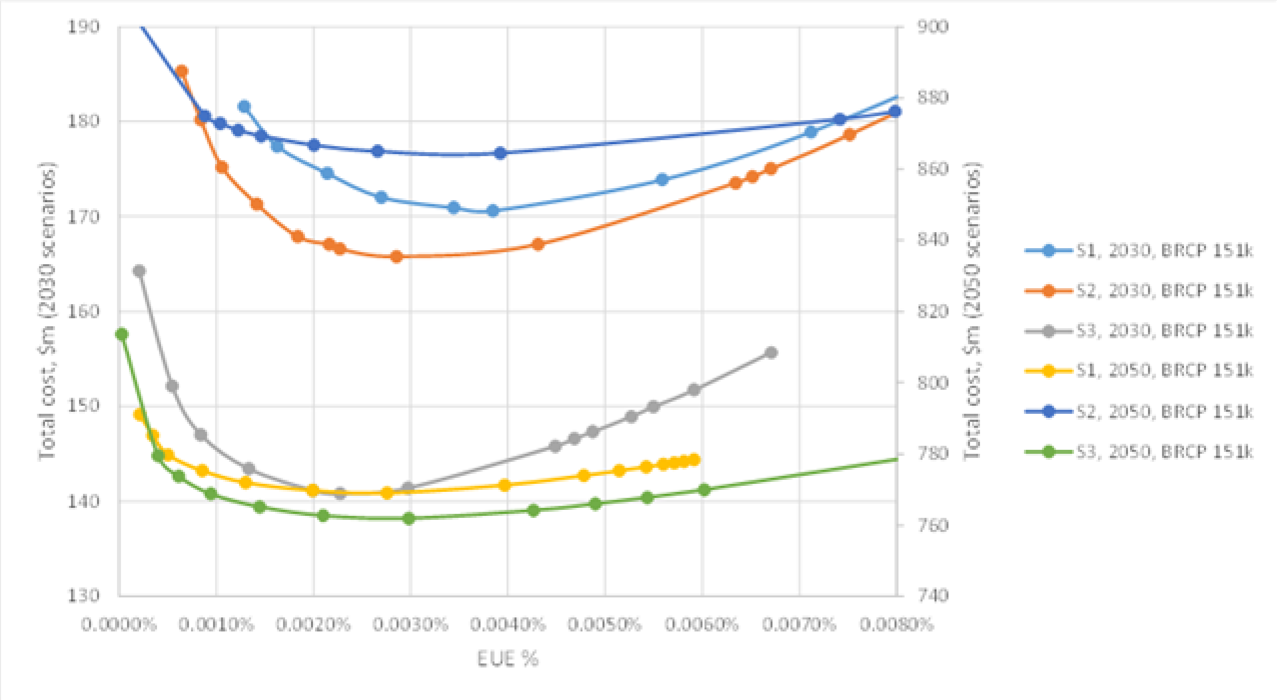
This approach is like that used by the NEM Reliability Panel in its 2022 Reliability Standard and Settings Review, which determined an optimal value for the NEM of 0.0015% EUE.

Figure 12, Figure 13, and Figure 14 show the system costs for various levels of EUE under the various build scenarios. Costs are calculated as:

*EUE (MWh) * VCR + RCP * added capacity (MW).*[14]

The lowest point on the curve is the optimal EUE target under that scenario.

Figure 12: System costs and EUE levels – BRCP 152k/MW



13 Western Power's estimation of VCR can be found on the ERA's website in the document AAI – Attachment 6.3: [Access Arrangement 2022-2027 - Economic Regulation Authority Western Australia (erawa.com.au)]

14 The capacity cost used is the annual capacity payment to new capacity built after 2022. Capacity payments to existing facilities are not affected by the choice of EUE percentage.

Figure 13: System costs and EUE levels – BRCP 117k/MW

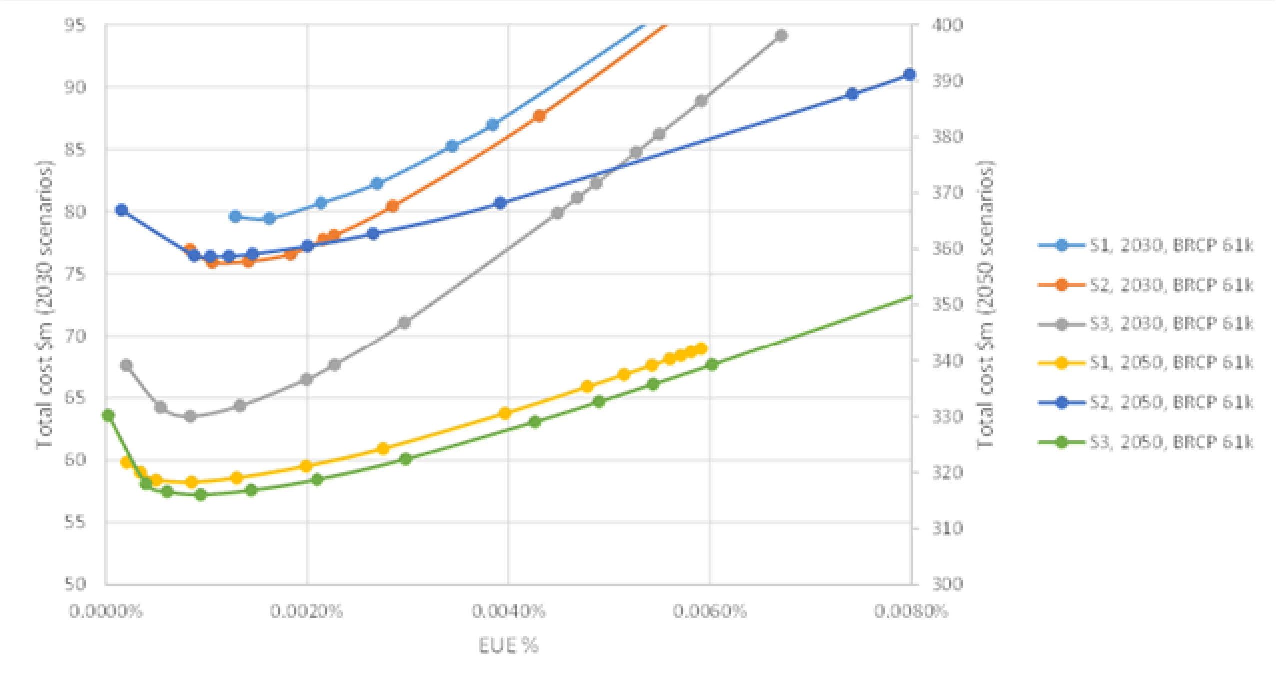


Figure 14: System costs and EUE levels – BRCP 61k/MW

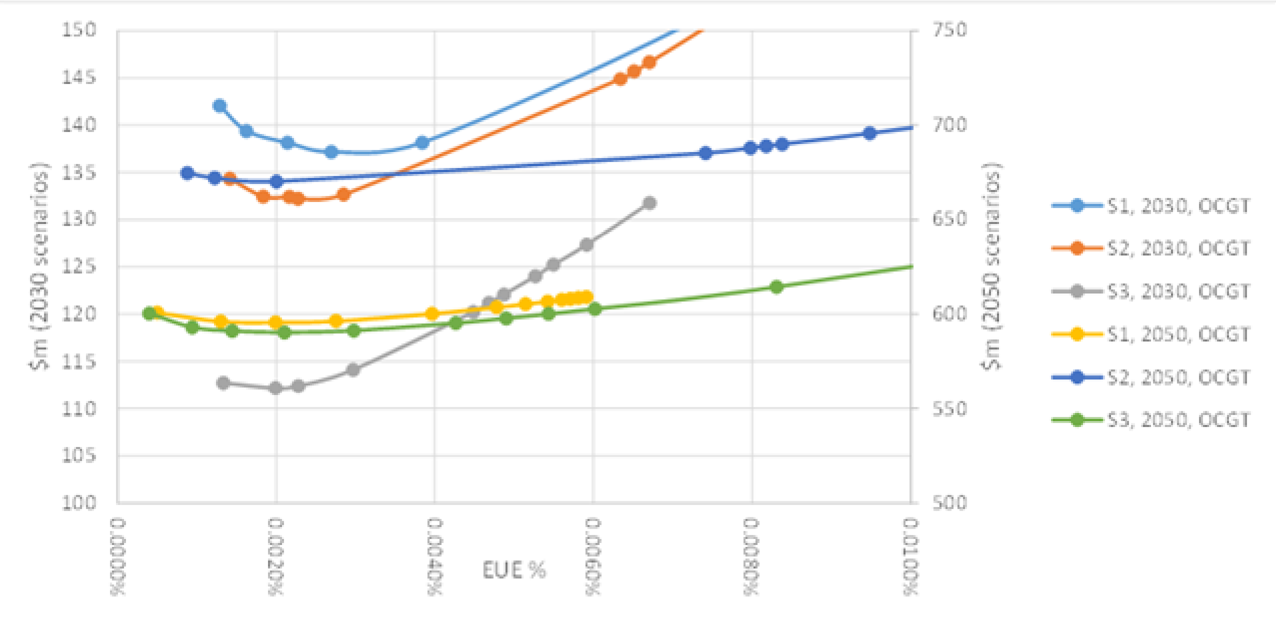


Figure 12, Figure 13, and Figure 14 show that:

- when the RCP reflects a continuation of current BRCP levels, the minimum cost point is at an EUE that is higher than the current 0.002% level in all scenarios;
- when the RCP reflects a BRCP of around $115,000/MW, the minimum cost point is an EUE that is higher than the current 0.002% level in one 2030 scenario, lower in one 2050 scenario, and very close to 0.002% in the other scenarios; and
- if the BRCP decreases significantly, setting the EUE target lower than 0.002% could reduce overall costs.

Given the uncertainty about the future reference technology, and therefore the BRCP, it is considered that there is currently no strong justification for changing the EUE target.

Conceptual Design Proposal 7:

The target EUE percentage in the second limb of the Planning Criterion will remain at 0.002% of annual energy consumption.

Consultation Questions:

(7) Do stakeholders support retaining the target EUE percentage at 0.002?

3.2 Planning Criterion for operational reliability

3.2.1 The need for flexible capacity

System stress modelling indicates that ramping needs will become more extreme in the future (see Figure 7). This need cannot be met by all capacity that is eligible for the existing 'peak' capacity service. As shown in Figure 8, without a separate financial incentive, there may not be sufficient flexible capacity to move supply quickly from the low load in the middle of the day through to the evening peak.

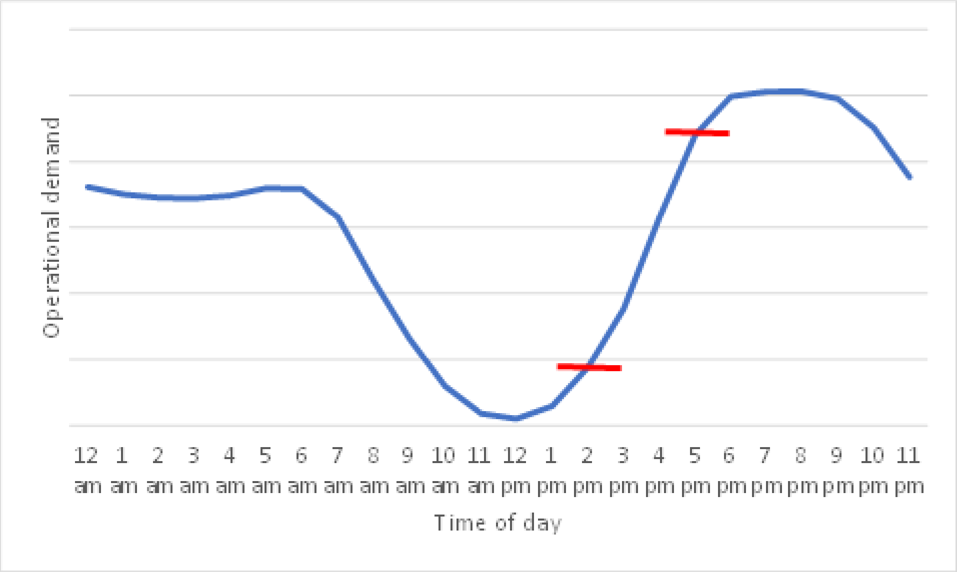
Capacity that can contribute to meeting the ramping requirements would likely also be capable of providing the range of Frequency Co-optimised Essential System Services (FCESS) in the WEM.

Therefore, it is proposed that a third limb be added to the Planning Criterion to set a second capacity target for flexible capacity.

3.2.2 Setting the target for flexible capacity

The key parameters driving the need for flexible capacity are the magnitude, slope and duration of the most extreme ramp expected in the capacity year. The flexible capacity target would be set in the Electricity Statement of Opportunities (ESOO), based on the steepest ramp period expected, as shown by the segment between red lines in Figure 15. The red lines are not set at the absolute minimum and maximum, as the start and end of the ramp is at a shallower rate.

Figure 15: Basis for the flexible capacity target



AEMO would need to assess the maximum operational ramp in each day of the year as the difference in the operational load at the start and end of the steepest daily ramp period and set the flexible capacity target at the maximum quantity observed.

Using the operational load means that the new limb of the Planning Criterion will only account for uncontrollable ramp. AEMO would need to consider both the 10% and 50% POE load forecasts to be consistent with the measure used for the peak capacity target while accounting for potentially steeper ramps from lower minimum demand levels.

Definition of the start and end points for the ramp period needs to be considered as, although the overall ramp is from the minimum load to the maximum load, the start and end of the ramp will be at lower rates that will not need to be explicitly included.

Conceptual design proposal 8:

The Planning Criterion will include a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the capacity year from either the 10% or 50% POE load forecasts.

Consultation Questions:

(8) Do stakeholders support the proposed third limb of the Planning Criterion to require AEMO to procure flexible capacity? If so, is the proposed criterion appropriate?

3.2.3 Proposal: defining flexible capacity

It is proposed that AEMO would set a second reserve capacity target (in MW) and procure sufficient flexible capacity to collectively:

- meet a defined minimum ramp requirement; and
- maintain it over a defined duration.

For example, this might be expressed as a total ramp requirement of 3000 MW over the three-hour period from 2:00 pm to 5:00 pm (averaging 1000 MW per hour).

Facilities, which can also meet the flexibility requirements, would apply for CRC for both products at the same time, with upgrades distinct from existing capacity, as is the case for the peak product today. Facilities may receive different CRC quantities for the peak product and for the flexibility product.

To be certified to provide flexible capacity, a facility would need to be able to demonstrate:

- the maximum ramp rate it could deliver;
- the total MW quantity it could ramp by over the defined time period;
- the maximum MW quantity it could deliver at the end of the defined time period;
- whether there are any energy or availability limitations, which mean that being dispatched to ramp as required would affect its availability to provide the peak capacity product; and
- whether its capability differs at different times of day or at different ambient conditions.

To be eligible for certification, the facility would need to have:

- short start, load, minimum run, stop, and restart times; and
- low or zero minimum generation level.

It is proposed that intermittent generators would be eligible to provide flexible capacity but would have their flexibility CRC capped at their peak capacity CRC to reflect the uncertainty of their contribution.

A facility with a low ramp rate would be unlikely to receive flexible CRC for its full capacity, but only for the MW change it could deliver over the defined period.

A facility that would not be fully available at the end of the defined period would not receive flexible CRC.

Further consideration needs to be given to the appropriate treatment of a facility with availability limitations which mean that it could not ramp as required and then continue to provide the peak capacity service.

The flexible capacity product will need its own cost recovery and refund mechanism and will be incorporated into the NAQ regime. These aspects will be explored in stage two of the RCM Review, but it is anticipated that the design will parallel the arrangements for the peak capacity product as far as is practicable.

4. The Benchmark Reserve Capacity Price

A major benefit of the capacity mechanism – both when originally implemented and today – is to allow relatively low energy price caps in the energy markets. Because of the capacity payments, market participants do not need extreme energy prices periodically to earn a return on their investment.

The WEM market components (RCM, energy and ESS) must collectively provide the means for providers of market services to recover all of their long-run costs – both capital and operating. The WEM does not guarantee that inefficient long-run costs will be recovered but should at least provide a clear view to investors on how an efficient provider would get a return on its investment.

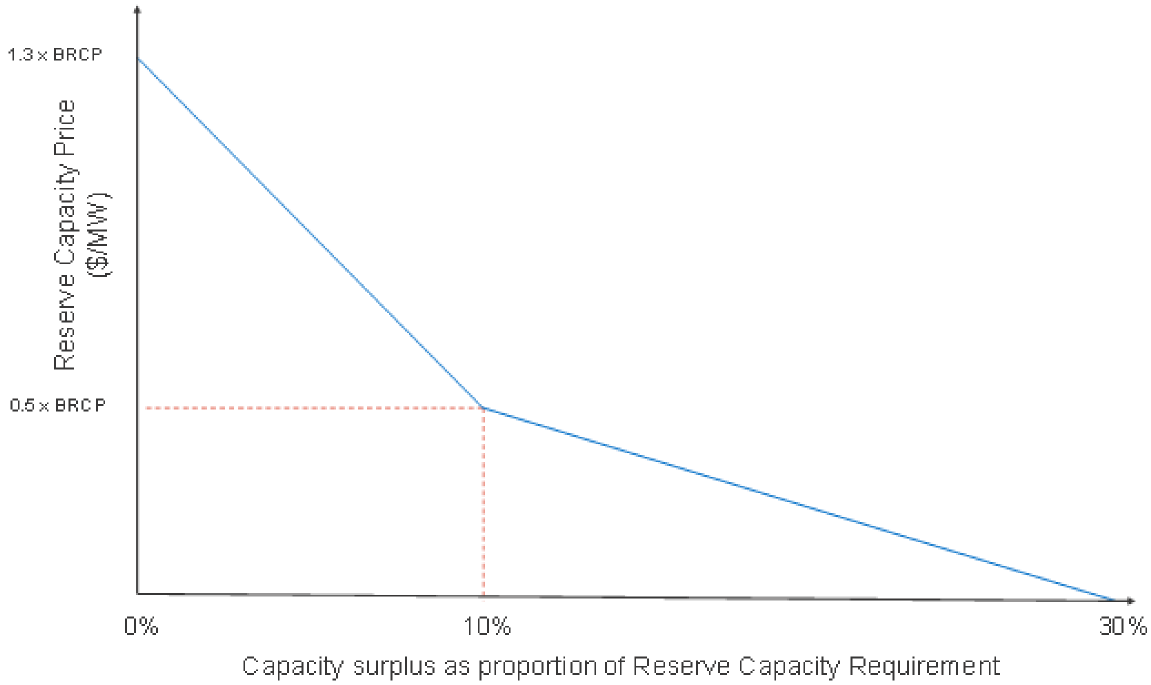
The administered RCP received by facilities holding Capacity Credits provides a signal of over- or under-capacity in the WEM. This and most other aspects of the reserve capacity pricing arrangements are not in scope of this review. The methodology used to set the BRCP is in scope, however, for both the existing peak capacity product and the new flexible capacity product. The BRCPs must be considered in conjunction with the offer and price caps in Short Term Energy Market (STEM), real-time energy market and ESS market.

4.1 The current BRCP methodology

The BRCP is the anchor for the administered RCP. The monetary value of Capacity Credits is currently not affected by the technology of a facility.[15]

As illustrated in Figure 16, depending on whether there is under- or over-supply of capacity, the actual administered RCP received by each facility may be greater than (up to 130% of) or less than (down to 0% of) the BRCP.

Figure 16: Administered capacity price curve



15 During the period from the 2017 Capacity Year to the 2020 Capacity Year, inclusive, a lower price was paid for Capacity Credits assigned to Demand Side Management Programmes (DSPs)

The WEM Rules give the Economic Regulation Authority (ERA) responsibility for setting the BRCP, and originally specified how the BRCP should be determined in an appendix to the WEM Rules, but currently provide little guidance to the ERA. The entirety of the method is delegated to a WEM Procedure developed and published by the ERA, and the BRCP is defined as the price determined under that procedure.

The ERA's WEM Procedure: Benchmark Reserve Capacity Price[16] sets out the detailed methodology that determines the BRCP for each capacity year. The WEM Procedure defines a specific power station to be used as the basis for the BRCP: a 160 MW liquid fuelled OCGT, the configuration of the station, and various commercial and financial parameters that are needed to determine the total fixed costs of the facility. The capital and fixed operating costs are annualized over a 15-year period and divided by the expected facility capacity at 41ºC to give a cost per MW of capacity.

Thus, the BRCP is currently set at the gross Cost of New Entry (CONE) for a liquid fuelled 160 MW OCGT. The same basic technology has been used since market start.

It is considered that, while details of the BRCP determination can continue to be delegated to a WEM Procedure, the WEM Rules should provide guidance or a high-level methodology for setting the BRCP. The overall form of the BRCP methodology remains sound, including:

- the definition of the reference facility;
- the costs to be accounted for in determining the fixed cost of the reference facility, including development costs, transmission costs, and fixed operating and maintenance costs; and
- the method for annualising the facility fixed costs, including the weighted average cost of capital (WACC).

While OCGT technology will have a place in the fleet for at least the next ten years, it may not remain the relevant reference technology for the BRCP. At some point, either:

- an OCGT will no longer be the lowest cost source of new capacity; or
- it will no longer be credible that OCGT can be built; or
- network location considerations may mean that an OCGT cannot be built without capacity being de-rated by the NAQ arrangements.

When this happens a storage facility will likely become the new reference technology and the BRCP methodology may need to switch to a net CONE basis to recognise that a storage facility will likely earn higher profits in the energy and ESS markets. This will increase the complexity of the BRCP method.

The current structure of the procedure will remain relevant for determining the fixed costs of the facility and the approach to annualisation, but it will need to be extended to include new relevant factors and considerations.

Conceptual Design Proposal 9:

- The ERA will remain responsible for setting the detail of the method used to calculate the BRCP.

16 https://www.erawa.com.au/cproot/21540/2/Market-Procedure---Benchmark-reserve-capacity-price---version-7---Approved-for-publishing.PDF

- The WEM Rules will provide guidance for the ERA on the factors to be considered in setting the BRCP methodology.

Consultation Questions:

(9)(a) Do stakeholders support retaining the ERA as the agency that is to set the BRCP?

(9)(b) Do stakeholders support providing guidance to the ERA in the WEM Rules on the factors to consider in setting the BRCP?

4.2 Selecting a reference technology

The RCM has an administered price regime, and the process for setting the RCP is intended to signal whether new capacity is needed to meet the reliability target, and to provide appropriate incentives to invest when needed and to signal when investment is not needed, so the consumer interests are protected. Signals for investment are sent by pricing outcomes in all markets, including energy only markets. The capacity target in WA has been exceeded each year for more than a decade, indicating that current price settings have been sufficient to encourage the necessary level of new investment.

An OCGT facility has historically had the lowest per MW capital cost of any potential new entrant technology to the WEM. It has been the lowest cost source of new capacity, even though it is not the lowest cost per MWh source of new energy.

This has been the case in most capacity markets around the world. Recently, some markets have started to move to a combined cycle gas turbine (CCGT) as the reference technology, on the basis that it is more likely to be the next new entrant than an OCGT. CCGTs have higher capital costs than OCGT but lower variable costs, meaning that they can earn more than their short-run costs in the energy and ESS markets, thus recovering some contribution towards their long run marginal costs outside of the capacity mechanism.

In the WEM, all new capacity in recent years has been wind and solar generation (as the marginal new entrant providing energy), but OCGT and CCGT can still be built.

The BRCP should continue to be based on the lowest capital cost ($/MW) for the marginal new entry capacity resource. If the BRCP is set based on a more expensive technology while a lower cost facility can still be built, the lower cost new entrant would receive a capacity price reflecting a higher capital investment, and be overcompensated for its costs. This would tend to encourage overcapacity in the SWIS.

However, if the BRCP is set based on a lower cost technology that cannot be built in practice, the BRCP may be too low to encourage the marginal new entrant, resulting in a capacity shortage.

CSIRO's most recent generation cost report[17] shows that a large (~250MW unit size) OCGT remains the lowest capital cost option in 2022, while small (~50MW unit size) OCGT is more expensive. Costs for both are expected to decline modestly over the study horizon.

The cost of battery storage technology has reduced significantly in recent years, but the future trajectory remains uncertain. The cost of battery storage will decline further over the course of the study horizon, but the rate and timing of when its cost becomes lower than an OCGT cost is unclear.

[17] https://www.csiro.au/-/media/News-releases/2022/GenCost-2022/GenCost2021-22Final_20220708.pdf

Figure 17, Figure 18, and Figure 19 show the estimated capital costs for OCGT and battery storage technologies from 2021 to 2050.

Figure 17: Technology capital costs - CSIRO current policies scenario

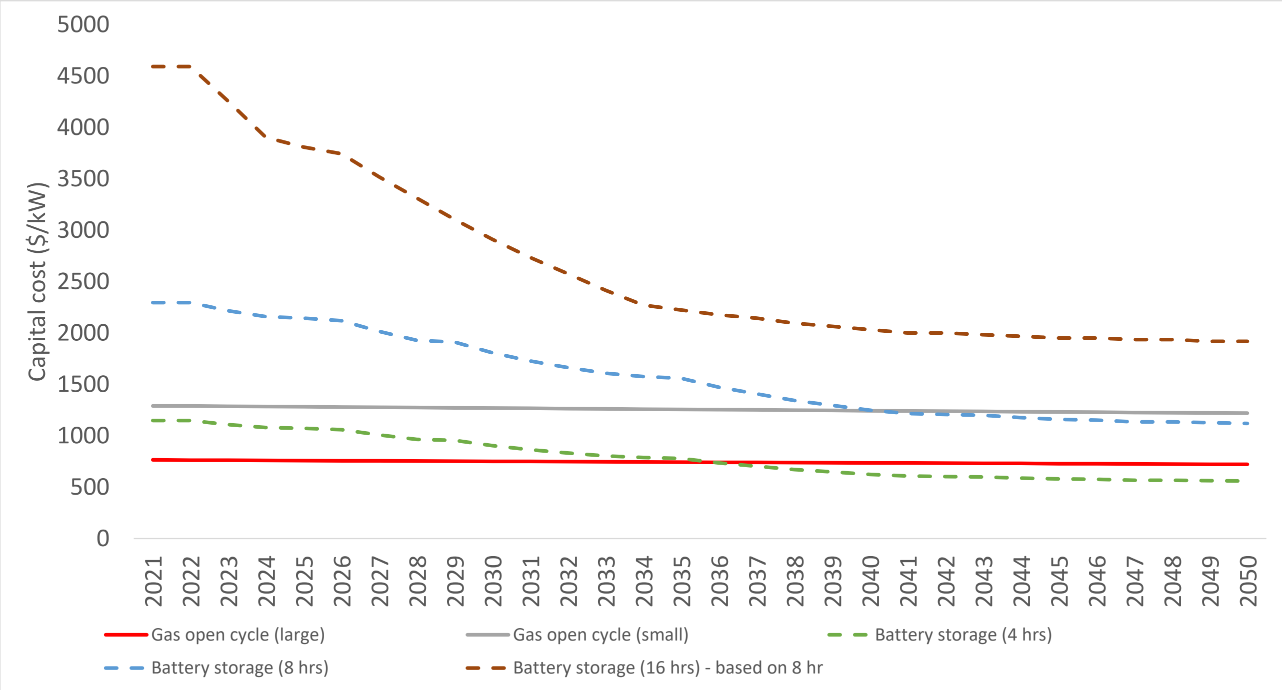
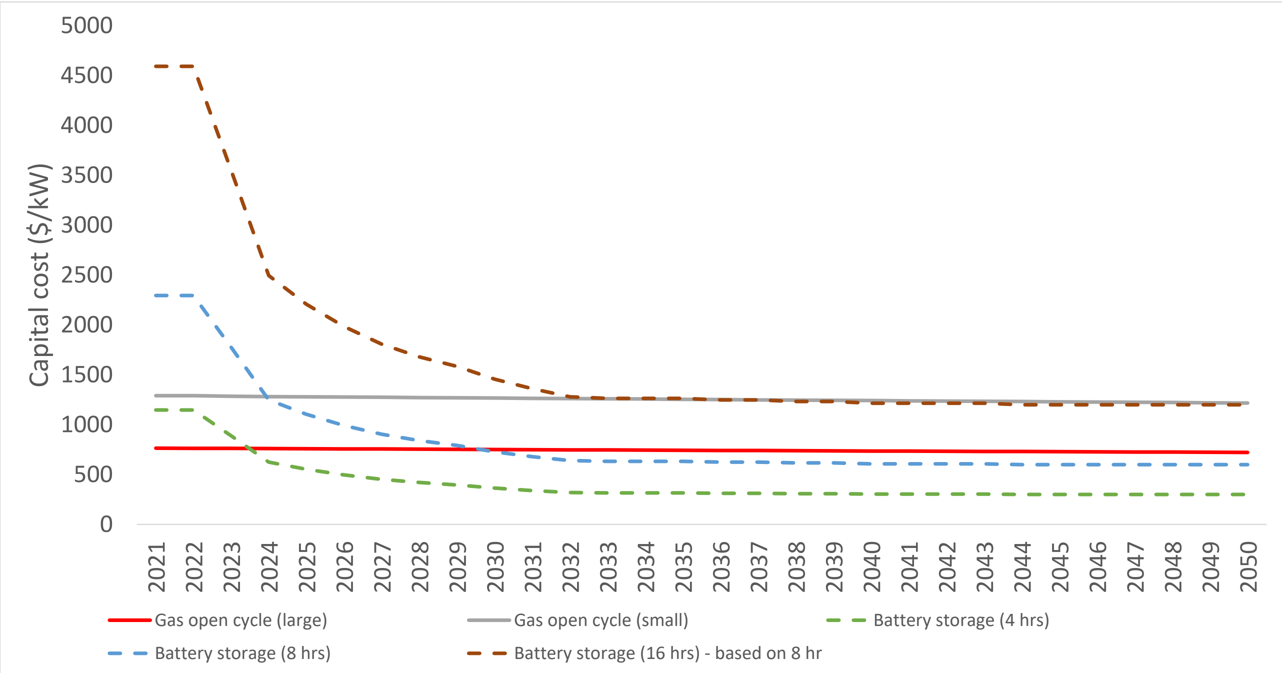


Figure 18: Technology capital costs - CSIRO global net zero by 2050 scenario

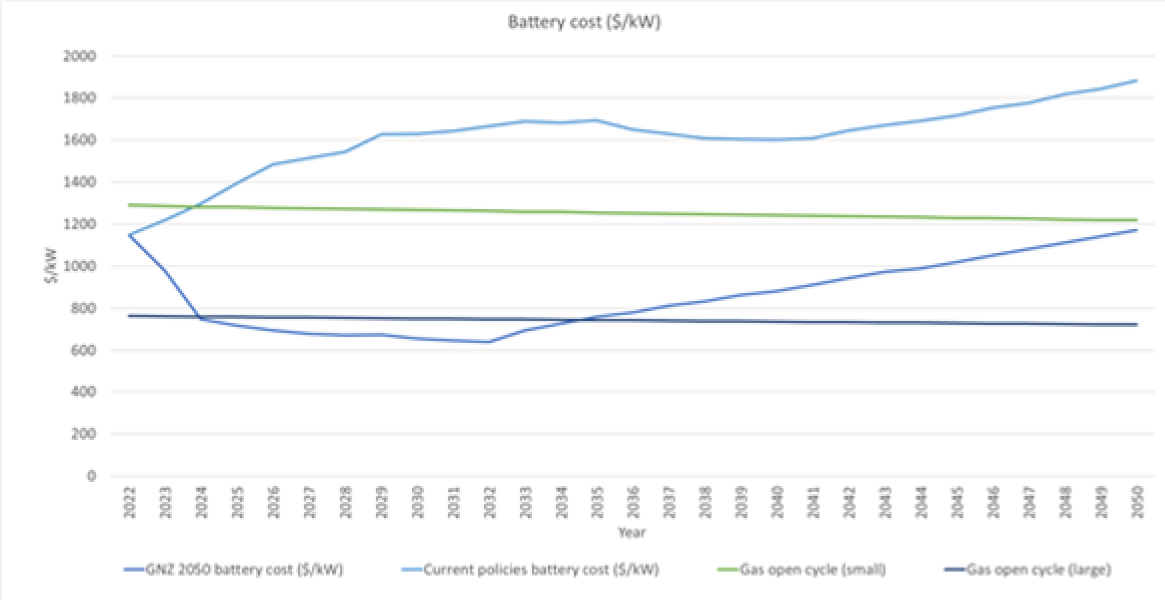


In the ‘current policies’ scenario (Figure 17), a four-hour battery has already lower cost than a small OCGT and its cost will become lower than the cost of a large OCGT in the mid-2030s. In the ‘net zero by 2050’ scenario (Figure 18), the cost of a four-hour battery will become lower than the cost of a large OCGT in the 2020s, and the cost of an eight-hour battery will become lower than cost of a large OCGT around 2030.

However, the situation is complicated because the required duration for storage will extend over time. While four hours of storage will be sufficient for the next few years, eight hours of storage is likely to be needed by the early 2030s, and by 2050, storage may need to provide capacity through the evening peak and all the way through to the following morning. The ERA will need to consider the required storage duration when setting the BRCP, and this duration will need to align with the availability duration requirement determined by AEMO (see section 5.2 for further discussion)

Figure 19 shows capital costs for gradually extending battery storage lengths, starting in 2022 at the four-hour storage cost, then increasing the average length to reach eight hours in 2032, and then continuing to reach 16 hours in 2050.

Figure 19: Technology capital costs - blended battery storage lengths



This analysis shows that an OCGT is likely to remain the new entrant with the lowest capacity costs for at least the next few years, until the trajectory of battery storage costs become clear.

All of this is contingent on the possibility of actually building an OCGT facility. Although there is no regulatory impediment to doing so:

- no new gas or liquid fired facilities have been built in the SWIS for some years;
- the WA Government has recently announced that Synergy will not build any more gas fired facilities after 2030;
- financial institutions are increasingly reticent to fund fossil fuel projects; and
- at least one existing OCGT facility has shut down in recent years.

The Minister for Energy's Draft Statement of Policy Principles: Penalties for high emission technologies in the Wholesale Electricity Market,[18] may also affect the capacity pricing regime. EPWA has not yet considered how to implement these policy principles, but initial direction is that they would be considered as part of the RCM Review and, potentially, could be implemented through the RCM.

At some point battery storage of an appropriate length will become lower cost than an OCGT, or it will no longer be credible for an OCGT to be built. At that point, the reference technology must change. This means that the ERA's periodic reviews of the BRCP methodology will become more

18 The draft statement was discussed with the MAC on 22 August 2022. Papers and minutes from that meeting can be found here: https://www.wa.gov.au/government/document-collections/market-advisory-committee-meetings-held-between-january-2022-and-december-2022.

important over the next decade, and the WEM Rules need to provide clear guidance to the ERA on the principles for setting the BRCP.

In the meantime, both OCGT and battery storage can be designed to provide flexible capacity, and so it is reasonable to expect that the reference technology for peak capacity and flexible capacity would be the same (though the rules should not preclude a different reference technology for each product at the same time).

The configuration of a facility that provides flexible capacity is likely to be slightly different to that of peak capacity. An OCGT may face additional costs to reduce its level of minimum stable generation, for example, using sequential combustion to avoid diffusion mode combustion when using dry low NOx burners for emission control[19].

Conceptual Design Proposal 10:

- The WEM Rules will define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortised over the expected life of the facility.
- A BRCP is to be calculated for each of the peak capacity product and the flexible capacity product, and the BRCP methodology must differentiate between the two, taking into account any differences between the reference technologies used for each product, where appropriate.
- The ERA review of the BRCP methodology (under clause 4.16.9 of the WEM Rules) must consider the appropriate reference technology, the design life of the relevant facility, and identify any cost components that differ between the technology providing the peak capacity product only and that providing the peak capacity plus the flexible capacity product.
- The ERA can review the BRCP methodology more frequently than every five years, if it considers that the reference technology has changed significantly, and must consult with stakeholders each time it does.

Consultation Questions:

(10)(a) Do stakeholders support the proposed approach to the BRCP?

(10)(b) Do stakeholders support the calculation of separate BRCPs for the peak and flexible capacity products?

(10)(c) Do stakeholders support the proposed factors for the ERA to consider in reviewing the BRCPs?

4.3 Gross CONE vs net CONE

The relatively peaky nature of the SWIS has meant that the marginal provider of capacity runs very seldom and has no ability to recover any contribution to its long-term costs in the energy markets.

19 See for example section 4.1.1 of ElectraNet's report on Generator Technical and Cost Parameters: https://www.electranet.com.au/wp-content/uploads/projects/2016/11/508986-REP-ElectraNet-Generator-Technical-And-Cost-Parameters-23July2020.pdf

EPWA has recently proposed[20] that the Max STEM Price (the highest allowable generation offer price in the STEM and real-time energy market) be set based on the highest short run cost facility in the fleet. This will continue the approach of allowing the highest short run cost facility to recover all of its short-run costs when it runs, but to not get a contribution to its fixed costs.

At present, the facility with the highest short run cost is also the facility with the lowest capital costs: an OCGT. These facilities rely on the RCM to recover all of their fixed costs. Therefore, the BRCP has been set based on the gross fixed costs of the representative facility (gross CONE).

However, if at some point the marginal capacity provider no longer has the highest short-run costs in the fleet, then it will recover some contribution to its capital costs through infra-marginal rents in the energy and ESS markets. In the coming years, when battery storage is the marginal capacity provider but some OCGT peaking units remain in the market, the marginal new entrant storage facility would expect to earn more than its short run costs in the energy and ESS markets. If this profit is not accounted for when setting the BRCP, the BRCP will overestimate the cost that must be recovered by the new capacity entry. Therefore, the BRCP would need to be based on the net CONE of the marginal capacity provider. The net CONE will likely trend back towards gross CONE over time, as the marginal capacity provider runs less frequently.

Economic modelling indicates that in the 2020s, when storage volumes are small, storage facilities can make short-run profits by charging when prices are low or negative and discharging in the peak hours, even in a 50% POE peak demand year (see Appendix D for more detail). This means that setting the BRCP based on the gross fixed costs of a storage facility would allow a new entrant to recover more than its fixed costs, which may incentivise overcapacity in the SWIS. However, whether this will, in practice, lead to capacity oversupply needs to be carefully examined in the next stage of the RCM Review, as other factors, outside of the RCM may influence investment decisions in the short term.

Revenues in the RCM and the real-time markets will also be affected by the location of a facility. Where a new facility locates in a congested area of the network, its NAQ allocation will likely be less than its nameplate capacity. The types of capacity likely to be the reference technology are also likely to have some flexibility over where to locate, and therefore could be assumed to locate in a part of the SWIS where network congestion is minimal. As long as there is a location in the SWIS that can accommodate a new facility of the relevant reference technology and size, the NAQ regime should not impact on the BRCP.

Conceptual Design Proposal 11:

- Where the RCM reference technology has the highest short-run costs in the fleet, the BRCP methodology can use the simpler gross CONE approach, as this will be the same as the net CONE.
- Where the RCM reference technology does not have the highest short-run costs in the fleet, the use of net CONE approach would need to be considered together with all other factors that may influence investment decisions.
- The BRCP will be set based on a facility located in the least congested part of the network. If there is no uncongested network location to accommodate the size of the lowest fixed cost technology, the NAQ regime may affect the choice of reference technology. This location will be considered as part of the ERA's regular review of the BRCP methodology.

[20] EPWA's consultation paper: Market Power Mitigation can be found here: https://www.wa.gov.au/system/files/2022-08/Market%20Power%20Mitigation%20Strategy%20-%20Consultation%20Paper.pdf

Consultation Questions:

(11) Do stakeholders support the proposed consideration of gross CONE and net CONE for determining the BRCP, as indicated in Conceptual Design Proposal 11?

4.4 Accounting for two capacity products

Some facilities will only be able to provide peak capacity. Other facilities will be able to provide both peak capacity and flexible capacity. It is not anticipated that any facility would provide flexible capacity without providing peak capacity.

Participants would apply for both kinds of capacity at the same time – if a facility could provide flexible capacity but only applied for peak capacity, then it will not be eligible for flexible product Capacity Credits.

Pricing arrangements for the capacity products need to ensure that:

- all facilities receive at least the peak capacity price;
- if there is an oversupply of flexible capacity, no additional payments are made to facilities providing both products; and
- if there is sufficient peak capacity, but insufficient flexible capacity, all facilities providing flexible capacity receive a price higher than the peak capacity price (including new facilities built to meet the shortfall, and existing facilities providing flexible capacity).

This could be arranged by:

- calculating the flexible capacity price as an increment to the peak capacity price;
- setting a non-zero flexible capacity price only if new facilities are needed to meet the flexible capacity target;
- calculating standalone capacity prices for each product, and applying the flexible capacity price to any facility that provides both peak and flexible capacity, and setting the floor for the flexible capacity price at the peak capacity price; or
- calculating standalone capacity prices for each product and applying the higher of the two prices to any facility that provides both peak capacity and flexible capacity.

It is considered that the last two options will have equivalent outcomes, and is clearer than the former options.

This means that the two capacity products would be treated as two separate but related products: there will be two Reserve Capacity Targets, two BRCPs, two capacity price curves, and two RCPs – one for each of the peak capacity and the flexible capacity products.

The peak and flexible capacity prices will vary from their respective BRCPs depending on the level of over- or under-supply of the relevant capacity product.

The definition of the administered price curve for the peak capacity product is out of scope for the review, but it is necessary to determine a price curve for the flexible capacity product. The price curve functions to:

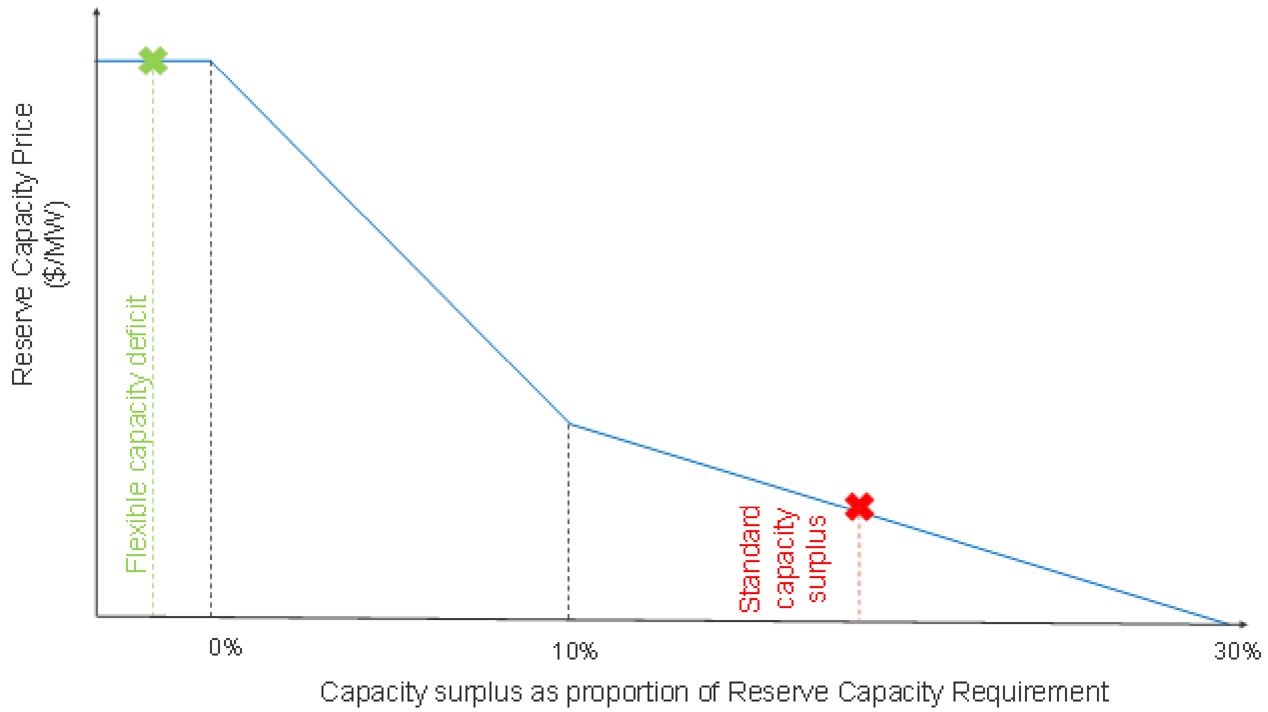
- smooth out fluctuations in the capacity price from year to year
- allow for potential mismatch between the BRCP and the actual marginal cost of new capacity
- reduce the amount paid when there is surplus capacity

- increase the amount paid when there is a capacity shortfall

The peak capacity price curve has been defined for the specific circumstances of the WEM. Using a different shape for the flexible capacity product price curve would increase complexity of the mechanism, and risk a mismatch in the relative incentives for the two products.

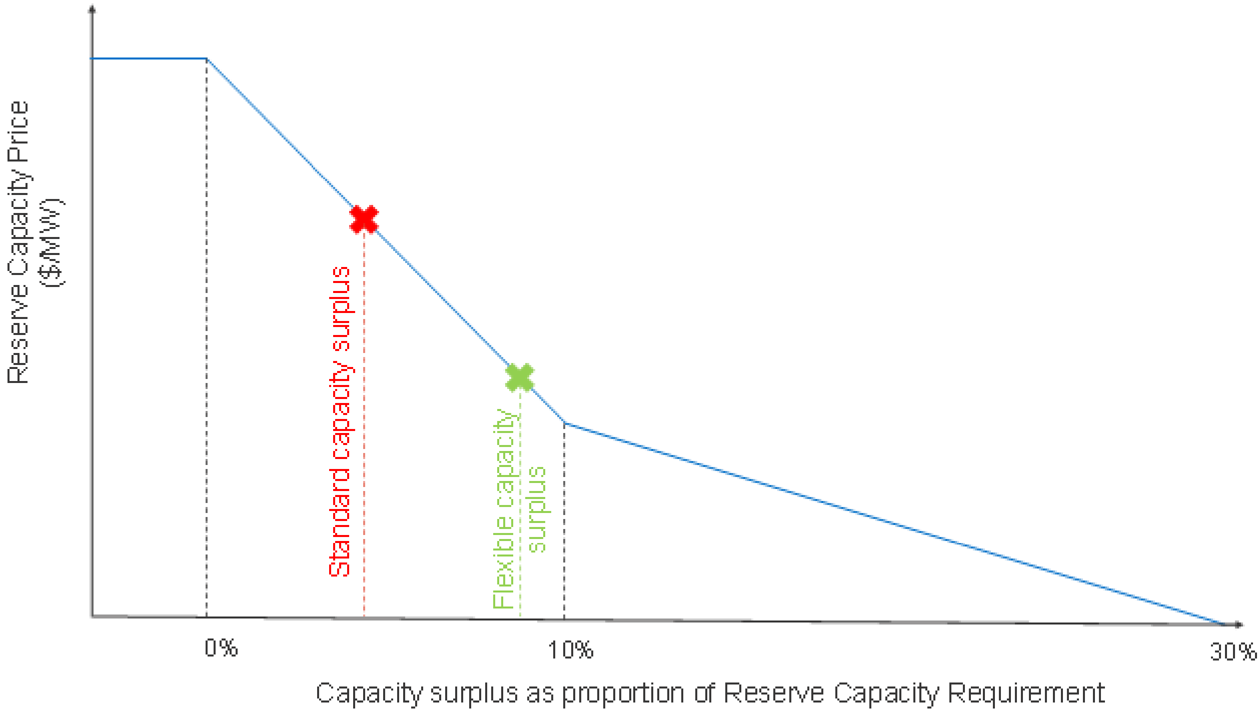
No compelling reasons were identified to use differently shaped price curves for the two products and so it is proposed to set the price curve for the flexible capacity product using the formula in clause 4.29.1(b)(iv) of the WEM Rules. Using the same shaped price curve means if there is a shortfall in flexible capacity and an oversupply of peak capacity, the flexible capacity product would have a higher price (as shown in Figure 20).

Figure 20: Insufficient flexible capacity provided by existing facilities, facilities providing flexible capacity receive a higher capacity price



As long as facilities are paid at least the peak capacity price for the portion of their capacity that provides both services, when there is plenty of flexible capacity, overall capacity costs will be no more than they would have been in the absence of the flexibility product (as shown in Figure 21). Where there is a surplus of peak capacity, there would be additional costs associated with the flexible capacity product.

Figure 21: Sufficient flexible capacity provided by existing facilities, all facilities receive standard capacity price



To incentivize participants to make capacity available for both products from the outset, and prevent strategic withholding at the time of certification, it is important that existing facilities would be eligible for the same payment per MW as new facilities.

Setting the capacity price for a portion of a facility that provides both products at the higher of the two product prices would avoid overcompensation, preserve the pricing signals for both products, and avoid incentives to withhold capacity.

To maintain consistency with the peak capacity product, facilities providing flexible capacity would have an option to lock in fixed pricing for the flexible capacity for five years, but would only be awarded Capacity Credits if there were a shortage of capacity applying for the floating price option. As some types of facility (such as pumped hydro storage) may need investment certainty for longer than five years, this could change over time as the need for longer duration storage becomes more pressing.

Although the definition of the RCM price curve is not in scope of this review, the international review of capacity mechanisms indicated that the WEM price curve is relatively shallow compared to that used in other jurisdictions. Economic modelling (see Appendix D) indicates that the next ERA review of the price curve may need to consider whether there is a sufficient price signal in times of projected capacity shortage.

Conceptual Design Proposal 12:

- The administered RCM price curve for the flexible capacity product will be the same as the one used for the peak capacity product, as defined in WEM Rule 4.29.1(b)(iv).
- The capacity price paid to a facility providing flexible capacity will never be lower than the peak capacity price.
- Proposed facilities will have the option to seek a five-year fixed price for flexible capacity, on the same basis as is currently available for peak capacity. A facility must opt for a fixed price for both products, it cannot select fixed price for one product and floating price for the other.

Consultation Questions:

(12)(a) Do stakeholders support using the same price curve for the peak and flexible capacity products?

(12)(b) Do stakeholders support the proposed pricing arrangements for the flexible capacity product?

(12)(c) Do stakeholders support a 5-year fixed price option for proposed flexible capacity facilities?

5. Capacity Certification

5.1 Valuing capability when certifying capacity

The current RCM requires scheduled facilities to always be available in the market, except when on a Planned Outage. This was based on the assumption that capacity needed to be available at all times to allow for the scheduling of outages.

In the current RCM, AEMO procures capacity up to the Reserve Capacity Target from facilities in the order of Availability Class. Existing and committed facilities in both classes are allocated Capacity Credits, but when there is more CRC than the Reserve Capacity Target, proposed facilities in Availability Class one are preferred to those in Availability Class two.

These Availability Classes do not include a dimension for the 'firmness' of the capacity, even though intermittent and non-intermittent facilities have different CRC allocation methods and different capacity obligations.

Further, retaining the current Availability Classes is not a viable option, as they do not allow for hybrid facilities, which may be increasingly prevalent.

It is therefore proposed to retire the existing Availability Classes and instead include the concept of 'Capability Classes' in the WEM Rules, which better aligns capacity allocation with firmness of delivery and availability obligations. There will be three Capability Classes:

- Class 1: Unrestricted firm capacity

  A Class 1 facility must be firm, dispatchable capacity with no fuel supply or availability limitations such that, if dispatched, it could run at maximum output for at least 14 hours. Class 1 facilities would be required to be available at all times (except when on outage), offer into both STEM and real-time markets as is currently the case for Scheduled Facilities, and meet their obligations if dispatched or be subject to capacity refunds if they fail to do so.

- Class 2: Restricted firm capacity

  A Class 2 facility must have firm, dispatchable capacity that is not eligible for Class 1 due to fuel supply or availability limitations. This might include a storage facility which is energy limited, a DSP which is only available at certain times of day or a dispatchable facility that has restrictions on fuel supply. Class 2 facilities would receive lower CRC based on their availability limitations (see section 5.2), and would be required to be available during specified hours, offer into the STEM and real-time markets in those hours, meet their obligations if dispatched during those hours or be subject to refunds if they fail to do so.

- Class 3: Non-firm capacity

  A Class 3 facility is one which does not provide firm, dispatchable capacity, such as a wind or solar farm without collocated firming capacity. Class 3 facilities would not have availability obligations (as is currently the case for Non-Scheduled facilities) but would expect to have significantly lower ratio of CRC to nameplate capacity than facilities in the other classes (see section 5.2).

The methodology for receiving Capacity Credits in Appendix 3 will need to be amended to use the new Capability Classes. It is proposed to use the following approach:

- all existing and committed facilities in all classes would be able to receive Capacity Credits;
- new proposed facilities would only be able to receive Capacity Credits if existing and committed facilities plus new proposed facilities in the higher Capability Classes are insufficient to meet the Reserve Capacity Target; and

- new proposed facilities in Class 1 would be accepted ahead of those in Class 2, and new proposed facilities in Class 2 would be accepted ahead of those in Class 3.

It is considered that capacity certification must evolve to allow treatment of hybrid facilities as a single entity. Separating storage from its co-located wind or solar generation for certification purposes will increasingly work against the behaviour required in a world with more intermittent generation.

Any technology can be nominated for any Capability Class. This includes DSPs and intermittent generators. Participants would need to provide evidence to demonstrate the class they nominate for their facility (particularly its ability to meet availability obligations), and will be subject to refunds for non-performance of their facility and AEMO could place a facility in another Class if its performance does not match its Class certification.

Participants would be required to show that each facility receiving CRC in Capability Class 1 has sufficient certainty of fuel access (for example, through a combination of onsite fuel storage[21] and fuel delivery contracts[22]) to deliver service for up to 14 hours during a system stress event (which is likely to last up to three to four days), and not being able to do so would affect Capability Class allocation.

Economic modelling shows that, at some point in the 2030s or 2040s, decreasing revenue for solar generation (both capacity and energy) means that it may not be economic to build a standalone solar plant to the levels assumed in the system stress scenarios, resulting in insufficient generating resources to charge the storage. At this point, storage facilities would not be able to rely on market-based charging and would need to show evidence of “fuel” supply arrangements that will allow them to produce energy.

It is considered that a 14-hour availability requirement to qualify as firm, unrestricted capacity is still valid. The requirement was originally put in place to ensure that liquid fuelled facilities had sufficient onsite fuel to operate for 4-5 hours a day for three days, without resupply. This consideration is still relevant, as system peak events in recent years have occurred over several days during periods of sustained high temperatures and high demand. It is considered that relaxing this requirement now risks reducing the level of reliability provided for by the WEM Rules. This would be counter to one of the objectives of the RCM review.

As the peak requirement changes over time, there will likely be sufficient intermittent generation to provide supply during the middle of the day. The duration gap analysis (see section 5.2) shows that, over time, the peak will flatten and extend, meaning that firm capacity will be needed overnight.

For these reasons, it is considered that it is reasonable to retain the 14-hour requirement for facilities in Capability Class 1. However, the new capability class arrangements mean that owners of existing facilities could choose to contract for less than 14 hours of fuel and be in Capability Class 2, with lower CRC, availability requirements to match their fuel availability, and refunds only for not performing in the intervals their capacity obligations apply.

It was considered to reduce availability requirements during mid-day hours, with AEMO setting indicative obligation hours in the ESOO for all Capability Classes, but it was decided that it is not appropriate to relax availability obligations through the midday period while firm generation is still likely to be needed to ensure power system security.

21 E.g. for facilities with fuel supplied by road.

22 E.g. for facilities with fuel supplied by pipeline.

It is acknowledged, however, that the current implementation of the fuel requirement in the WEM Procedure[23], which requires firm fuel availability during peak trading intervals on all business days of the year, may be more restrictive than is warranted to ensure fuel availability during times of system stress – particularly for facilities which usually operate in a mid-merit or peaking role. This will be further assessed in stage 2 of the review.

As noted in section 4.2, at some point in the 2030s or 2040s, it may be necessary to require storage facilities to demonstrate their access to energy sources for charging.

Conceptual Design Proposal 13:

- The current Availability Classes will be removed from the WEM Rules.
- The RCM will allocate facilities to one of three Capability Classes.
- CRC allocation methodologies will be amended to consider hybrid facilities as a single entity.
- Capability Class 1 facilities will be required to demonstrate fuel arrangements that enable them to run for 14-hours, with this requirement practical implementation to be considered in stage 2 of the review.
- Capability Class 1 facilities will be required to be available during all dispatch intervals, unless on an outage.

The proposed design for Capability Class 2 is outlined in design Proposal 14 and the design for Capability Class 3 will be developed in stage 2 of the RCM Review.

Consultation Questions:

(13)(a) Do stakeholders support replacement of the current Availability Classes with Capability Classes?

(13)(b) Do stakeholders support the conceptual design proposal for the Capability Classes?

(13)(c) Do stakeholders support retaining the 14-hour fuel requirement, with its practical implementation to be considered in stage 2 of the review, and the all-hours availability requirement for Capability Class 1?

5.2 The duration gap

System stress modelling showed that, after 2030, firm capacity duration becomes a key factor in serving load overnight. There will be a 'duration gap' between the end of the evening ramp (when flexible capacity that ramps up to meet the evening peak load may have exhausted its availability) and sunrise (when behind the meter and grid scale solar start to ramp up).

Modelling indicates that firm capacity will be needed by 2030 to shift energy from the middle of the day to the peak period, with a total duration of around six hours, but that in 2030 there will likely be sufficient gas fuelled facilities to fill most of the overnight need (along with a contribution from wind), meaning that storage facilities which can discharge over the few peak hours will be sufficient to serve load and achieve adequate reliability. By 2050, with all thermal generation retired, the

[23] https://aemo.com.au/-/media/files/electricity/wem/procedures/certification-of-reserve-capacity-for-the-2022-and-2023-reserve-capacity-cycles.pdf

overnight gap must be filled primarily by wind, storage, and DSM across a total duration of around 14 hours.

This means that facilities that cannot maintain output overnight would not provide the same contribution to system reliability as facilities that can.

The RCM needs to incorporate a signal of the needed availability duration as the market evolves over the years, and incentivise new entrant technologies to meet the duration requirement.

This duration requirement can be incorporated into the CRC allocation approach for Capability Class 2 facilities in a similar fashion to the current de-rating of ESR facilities, with AEMO calculating an availability duration target assuming:

- load is at the forecast 10% POE day operational load shape and magnitude;
- existing and committed Capability Class 1 capacity is fully available, but the total available capacity is de-rated by the same overall fleet outage rate used to calculate the reserve margin in the reserve capacity target;
- existing and committed Capability Class 2 capacity is available for its certified duration; and
- existing and committed Capability Class 3 facilities output is per their CRC.

The availability duration target would be calculated as the length of the period in which this capacity is not sufficient to meet the load[24], and Capability Class 2 availability obligation hours would be set accordingly.

The availability duration target would set the availability requirement for facilities in Capability Class 2. Facilities with insufficient fuel availability or storage duration to output at maximum for the entire duration target would receive a pro-rated CRC. For example, if the availability duration target was 10 hours, a facility with 8 hours availability at maximum output would receive CRC of 0.8 times its maximum output, and be required to make this quantity available during all hours of the availability duration requirement.

Because the availability duration target would change from year to year, the CRC received by a Capability Class 2 facility could change over time. The most cost effective 14-hour availability technology may be very different from the most cost effective 4-hour availability technology. Although the expected availability requirement for future years would be forecast in the ESOO, the uncertainty around what configuration to build could make it more difficult to secure finance for a new facility.

This uncertainty is similar to that which exists for capacity prices. To address the price uncertainty, the RCM pricing arrangements allow for a proposed facility to request a fixed price for a five-year period. Such a facility is only awarded CRC if there are insufficient non-fixed-price facilities to meet the reserve capacity target when capacity prices are likely to be high. This arrangement shifts price risk from developers to customers for the five-year period.

In the same way, the uncertainty around the future availability duration target could be addressed by including an option for new facilities to be assessed based on the availability duration target that applied when they were first certified for five years from commissioning (in the same way that they can request a capacity price fixed for five years). A proposed new facility requesting these arrangements would be selected only if existing, committed and proposed non-fixed-price capacity was not sufficient to meet the reserve capacity target.

[24] With a minimum of four hours, to match the current ESR obligation period.

It is considered that a five-year period would provide investment certainty, while not shifting significant risk to customers. Over time, as the need for longer-term storage becomes more pressing, EPWA may consider extending this period for such technologies. It is also noted that facilities with longer planning cycles than provided for by the standard capacity process can use the early certification process in section 4.28C of the WEM Rules.

Once the fixed-duration period was over, the facility would receive CRC based on de-rating over the prevailing availability duration requirement at that time.

Over time, if the peak does not flatten and extend as forecast, it may be appropriate to amend the duration gap approach to consider multiple availability durations for new facilities each year, whereby AEMO procures, for example, some Capability Class 2 capacity with four-hour duration, some with eight-hour duration, and some with 12-hour duration. It is considered that this additional complexity is not warranted at this time.

High level design proposal 14:

- AEMO will determine an availability duration requirement for new Capability Class 2 facilities, based on the capacity of the existing and committed fleet, and publish it in the ESOO, including forecasts for subsequent years.
- Capability Class 2 facilities will receive CRC equal to their maximum instantaneous output pro-rated by the number of hours they can sustain this output divided by the availability duration requirement.
- Proponents can request a five-year fixed availability duration requirement for a Class 2 facility but this request will only be accepted if the facility is needed to meet the reserve capacity target.

Consultation Questions:

(14)(a) Do stakeholders support the proposal for AEMO to calculate the availability duration requirement for each capacity cycle?

(14)(b) Do stakeholders support prorating the CRC for Capability Class 2 facilities in proportion to the availability duration requirement?

(14)(c) Do stakeholders support allowing proponents to request a 5-year fixed availability requirement?

5.3 Accounting for Forced Outages

5.3.1 ICAP

The RCM currently operates on an 'installed capacity' (ICAP) basis, where firm dispatchable facilities are allocated CRC without accounting for past or future forced outage rates, apart from exceptional circumstances. The ICAP of a Facility in the WEM is its maximum MW output at 41 degrees. When a facility suffers a forced outage, it is required to refund a portion of its capacity revenue to reflect that it has not met its obligations.

Because it is possible that some portion of the ICAP will be on forced outage (and paying capacity refunds) at the time of system peak, the Planning Criterion must consider the potential for forced outages occurring at peak times, and include an estimate of that unavailable capacity in the reserve margin. If it does not, then any forced outage will mean that there is insufficient capacity available to meet the requirements. If it does, then there will be sufficient capacity to meet the 10% POE peak load as long as the overall forced outage rate is no more than the historic rate.

As discussed in section 3.1.3 the reserve margin in the planning criterion also needs to cover the possibility of the largest contingency occurring at system peak. The required reserve margin is set at the larger of this and the overall proportion of the fleet expected to be unavailable at system peak.

5.3.2 UCAP

An alternative approach is to consider forced outage rates during certification, so that CRC is allocated based on 'UCAP'. This approach is used in other capacity mechanisms around the world, on the basis that it more closely aligns the procured product with what is actually delivered – i.e. a facility's CRC allocation includes the effects of expected forced outages, similar to how intermittent generation CRC is allocated based on expected performance rather than nameplate capacity.

A facility's historic Forced Outage Rate for a given time period (such as a year, or since commissioning) is the proportion of the period that the facility was offline due to a forced outage. The contribution of a partial outage is prorated to reflect the proportion of capacity that was unavailable.

Since forced outages are only likely to become apparent when a facility is actually running, facilities that run only infrequently are likely to have a very small forced outage rate. The EFORd adjusts for facility runtime in an attempt to place facilities on a consistent footing.

This UCAP implementation bases capacity allocation on historical performance that will not necessarily reflect future performance. EFORd can also be assessed on a forward-looking basis, either by adjusting historical outage data to remove uncharacteristic outages[25], or by using representative outage rates from similar facilities.

The UCAP for a Facility is its average generating capacity available after expected forced outages as adjusted for runtime.

$$UCAP = ICAP * (1 - EFORd)$$

UCAP allocates less CRC to facilities with poor outage records, more closely aligning the quantity of capacity procured and the quantity of capacity expected to be delivered (on average). For example a facility with an ICAP of 100 MW which ran 25% of the time (sitting idle 75% of the time) and had an overall forced outage rate of 5% across the whole year would have an EFORd of 20%, and a UCAP of 80 MW.

UCAP for scheduled facilities is similar to an effective load carrying capability (ELCC) approach, where the contribution of the facility is adjusted based on actual performance, as long as the facility's chance of an outage is not correlated with weather events.

If CRC is allocated on a UCAP basis, the peak limb of the Planning Criterion does not need to consider the expected fleet forced outage rate as forced outages have already been considered at CRC allocation time.

The WEM Rules (clause 4.11.1(h)) allow AEMO to reduce CRC allocated to a facility with sustained outage issues, but AEMO has never used this power.

Appendix C shows an example calculation of UCAP using outage and service data for 2012 to 2022. In this example, total Capacity Credits allocated would reduce by 8.7%[26].

25 Participants would be able to submit that certain outages are unrepresentative and should not be incorporated into historic outage rate, similar to how NTDL maintenance intervals are managed.

26 Under an ICAP approach, the planning criterion would need to ensure this percentage is added as a reserve margin to account for outages at peak.

5.3.3 Discussion

Under a UCAP approach, a facility’s contributing capacity is partially reduced at all times to reflect outages that reduce capacity some of the time. When the facility suffers a forced outage, its unavailable portion will usually be significantly more than the amount it was de-rated by.

Moving to a UCAP approach would require changes to either:

- relax the refund regime such that facilities are not subject to pay refunds until their actual EFORd exceeds the EFORd that they were certified at; or
- relax availability obligations so that facilities are required to offer only their de-rated capacity into the energy market, and only declare forced outages for that capacity.

Under an ICAP approach, a facility’s contributing capacity is not reduced, but it pays refunds specific to the hours in which it is not available. Since ICAP does not account for failure probabilities for individual generators, strong penalties for non-performance are needed to ensure the required level of system reliability.

The rules already make provision for facilities to have their CRC adjusted where their forced outage rate exceeds a threshold, but this is restricted to facilities with a forced outage rate of more than 10% over the previous three years. AEMO has not exercised this option. It is assumed that this is because the rules do not provide guidance on the appropriate circumstances to exercise this discretion.

It is considered that:

- the current refund regime is working well to incentivise availability, particularly at times when the reserve margin is low;
- an ICAP approach provides a stronger incentive for facilities to present all their capacity at peak time;
- an ICAP approach better aligns facility payments with actual performance during the capacity year; and
- where a specific facility has sustained poor outage performance:
  - the arrangements in clause 4.11.1(h) should be strengthened to require AEMO to reduce the CRC for the facility unless, in AEMO’s view, the underlying issues causing the high outage rate have been addressed such that the future outage rate is expected to be less than 10% in any three-year period;
  - A facility with CRC reduced under clause 4.11.1(h) should be excluded from the calculation of the fleet outage rate for the purposes of the planning criterion reserve margin, as its expected outage rate has already been accounted for.

The retention of the current ICAP approach was also broadly supported by the MAC and the RCMRWG.

Stage 2 of the RCM Review will consider specific aspects of the outage reporting regime, including how the CRC de-rating for high forced outage rates would be applied, whether forced outages resulting from dispatch non-compliance are excepted, and whether the lack of Dispatch Instructions for Synergy in under the current WEM Rules is likely to have a material impact on historical forced outage rates.

Conceptual Design Proposal 15:

- CRC allocation will remain on an ICAP basis, with refunds payable for any forced outage.

- The reserve margin in the first limb of the Planning Criterion will be set at the greater of the fleet-wide EFORd and the largest contingency expected at system peak, with AEMO assessing both each year.
- Where, over a three-year period, a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd.
- The method for calculating EFORd will also account for forced outages reported at times the relevant facility had not been called to run.
- A facility whose CRC has been reduced under clause 4.11.1(h) will be excluded from the calculation of fleet outage rate for the purposes of setting the planning criterion reserve margin.

Consultation Questions:

(15)(a) Do stakeholders support continuing to allocate CRC on an ICAP basis?

(15)(b) Do stakeholders support the conceptual design proposal for treatment of outages?

5.4 CRC assignment

A facility's expected contribution to system reliability is recognised by the level of CRC it is allocated. This section discusses options for assessing facility contributions, including methods proposed by the RCMRWG members during the development of these proposals.

In the current WEM, different technologies are assessed in different ways:

- non-intermittent generators are assessed based on their expected availability at 41 degrees Celsius;
- storage facilities are assessed based on their maximum output over a set duration (currently four hours);
- DSPs are assessed based on their historical load during high demand periods; and
- intermittent facilities are assessed based on their historical output in intervals with high non-intermittent generation, according to the Relevant Level Method (RLM) specified in Appendix 9 of the WEM Rules.

Selection of an appropriate method for CRC allocation for intermittent facilities requires further analysis, and will be concluded during stage two of the RCM Review.

5.4.1 The need to better reflect contribution to system reliability when assigning CRC to Intermittent Generators

The current RLM was designed for an environment where intermittent generation made up a small proportion of the fleet. It uses constant parameters in the calculation (the k and the u factors), the purpose and calculation of which is not defined under the WEM Rules. Market Participants and new entrants into the SWIS cannot calculate the value of these parameters. The current RLM is inconsistent with the Planning Criterion, because it focuses on performance in periods that do not directly relate to system stress intervals. Increased penetration of intermittent generators in the system will exacerbate the issues with the current RLM.[27]

[27] A detailed explanation of the shortcomings of the RLM is available in the ERA's 2018 review of the RLM.

As the number of intermittent generators in the SWIS continues to grow, it will become increasingly important to ensure that the CRC values of intermittent generators accurately reflect their actual contribution to system reliability and signal the value of firming the output of intermittent generators.

Ideally, a CRC allocation method for intermittent generators would:

- accurately reflect facility performance in periods of system stress;
- account for the correlation of output between facilities in the same location or affected by the same weather conditions;
- ensure those who are best placed to manage the risk of volatility in intermittent generator output are exposed to that risk; and
- minimise CRC volatility between years to provide certainty for investment.

5.4.2 The need to change the approach for assigning CRC to Demand Side Programmes

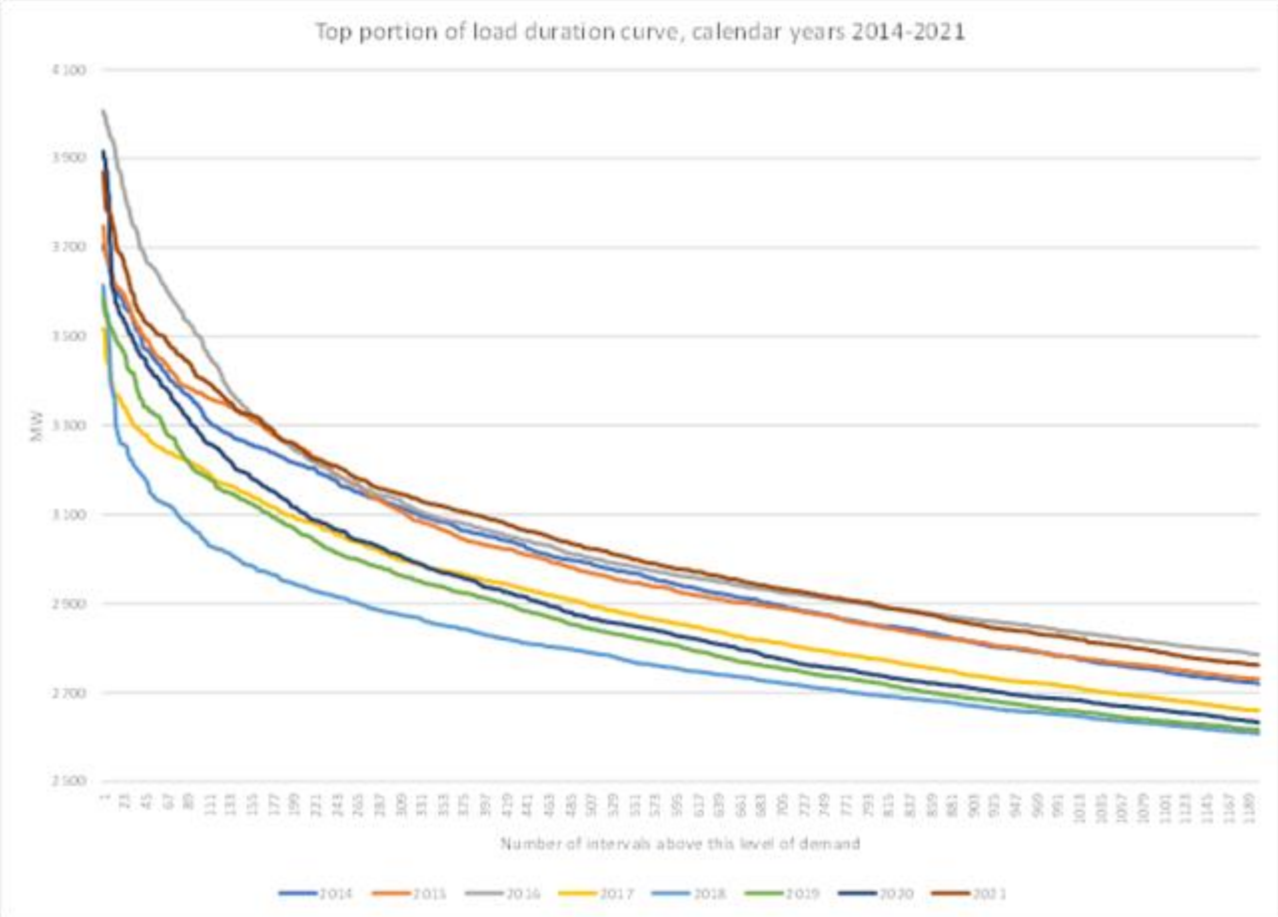
The current method for assessing the reliability contribution of DSPs is also problematic. It assesses potential performance at times of high demand periods, but these periods are not aligned with the periods used for the current RLM or the allocation of IRCR.

It is considered that, ideally, consistent methods should be used to assess CRC for DSPs and intermittent generators, and that IRCR allocation should also be aligned with this method. The treatment of DSPs and IRCR allocation will be analysed in stage 2 of the RCM review.

5.4.3 Intermittent Generator performance in system stress periods

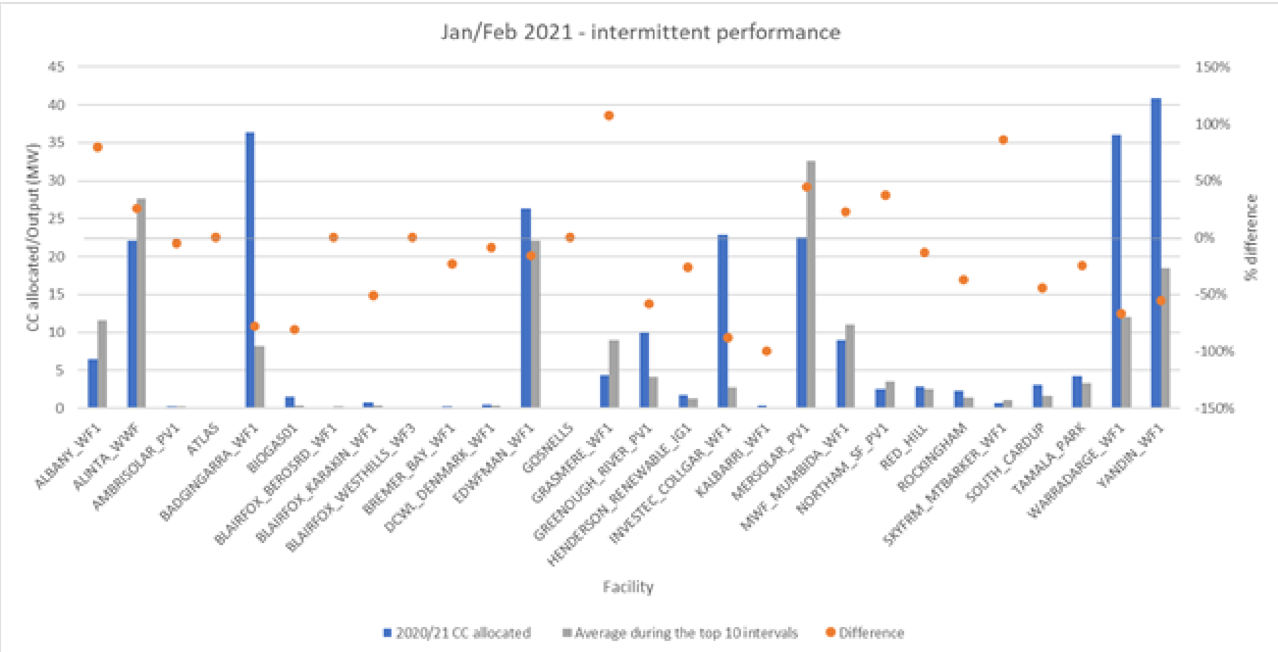
Western Australia experiences extreme system stress events very infrequently, and not all years have the same level of stress. For example, 2016 had 47 hours with higher demand than the 2017 peak. Figure 22 shows the 1200 hours with the highest load for each calendar year from 2014 to 2021. Each year has a very small number of intervals with very high load, and in some years the load reaches a considerably higher level than in others.

Figure 22: Peak portion of load duration curve by calendar year



Weather drives both demand and intermittent generation, so performance in historic stress intervals is the only real measure of expected performance in future stress intervals. For example, as shown in Figure 23, intermittent facilities performance during the 2021 summer peak intervals was below the level of capacity credits allocated.

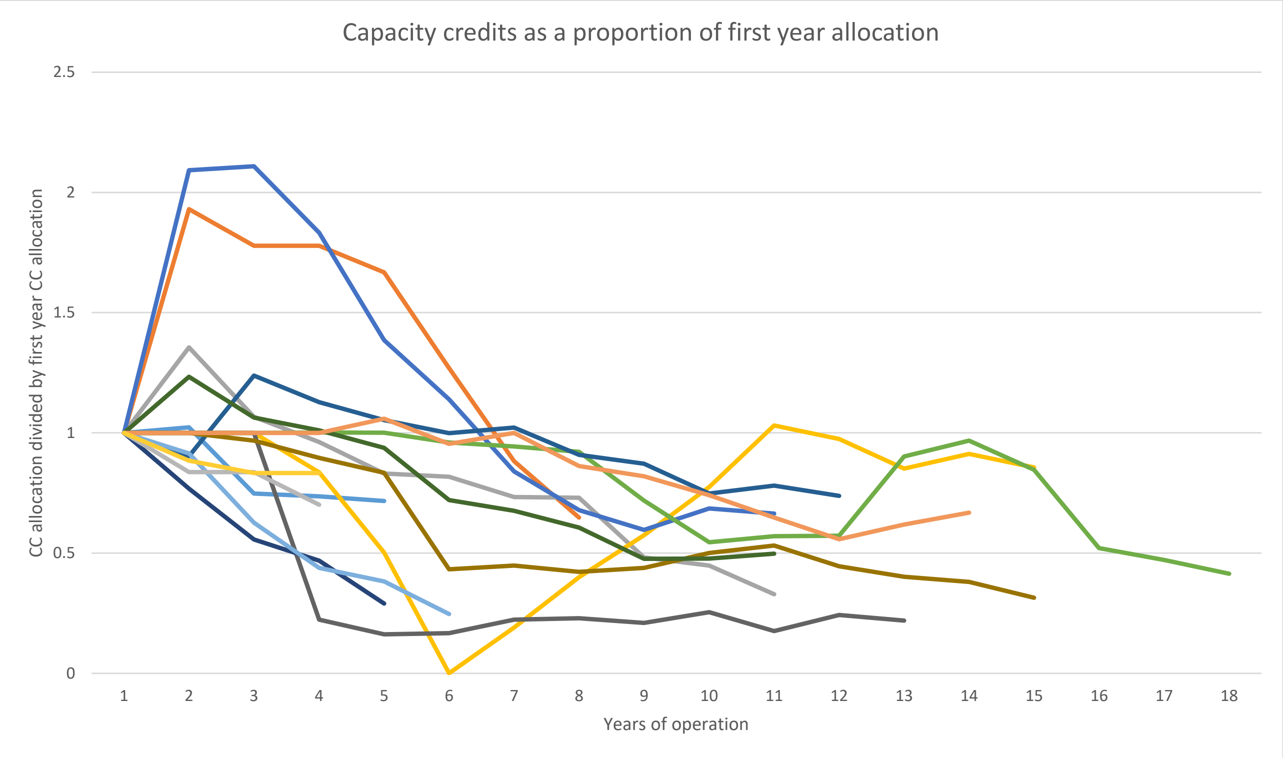
Figure 23: Intermittent facility performance in Jan/Feb 2021 peak periods



Expert reports

CRC assessment for new intermittent facilities is reliant on expert reports of estimated output for the historical reference period. While the overall trend in capacity allocation is affected by many factors, Figure 24 shows how intermittent facility CRC changes over time from the CRC it was allocated in its first year of operation (based solely on expert reports). Some facilities see a significant decline in their CRC over the first five years of operation (the period during which expert reports are used) and then stabilise.

Figure 24: Capacity Credit allocation for intermittent facilities



This may be due to overoptimistic expert estimates that result in overestimation of facility contribution. To reduce the potential for bias, it is considered that it would be appropriate to require AEMO to procure the reports on behalf of participants.

It is expected that the process for the procurement of these reports would need to be defined in a WEM Procedure and include specific measures to manage:

- conflicts of interest and confidentiality;
- protection of intellectual property; and
- cost efficiency.

Conceptual Design Proposal 16:

To ensure independent estimates of intermittent generator output, AEMO will procure expert reports to derive estimates of performance on behalf of participants.

Consultation Questions:

(16) Do stakeholders support requiring AEMO to procure expert reports on behalf of participants?

5.4.4 Alternative approaches to certifying the capacity contribution of intermittent facilities

Effective load carrying capability

As seen in the review of international capacity mechanisms published alongside this consultation paper, the contribution of intermittent facilities is sometimes assessed through probabilistic methods, including effective load carrying capability (ELCC[28]), equivalent firm capacity (EFC), and the marginal reliability index (MRI).

Under these approaches, intermittent facility CRC is based on actual contribution to system reliability, accounting for expected facility output at times of system stress.

The ELCC of a facility represents the amount of load that can be added to a system if this facility was added to the system, without increasing the system's LOLE. That is, the ELCC is determined as the firm capacity that could replace the assessed intermittent generator without changing the system's LOLE. The process is as follows, and is illustrated in Figure 25:

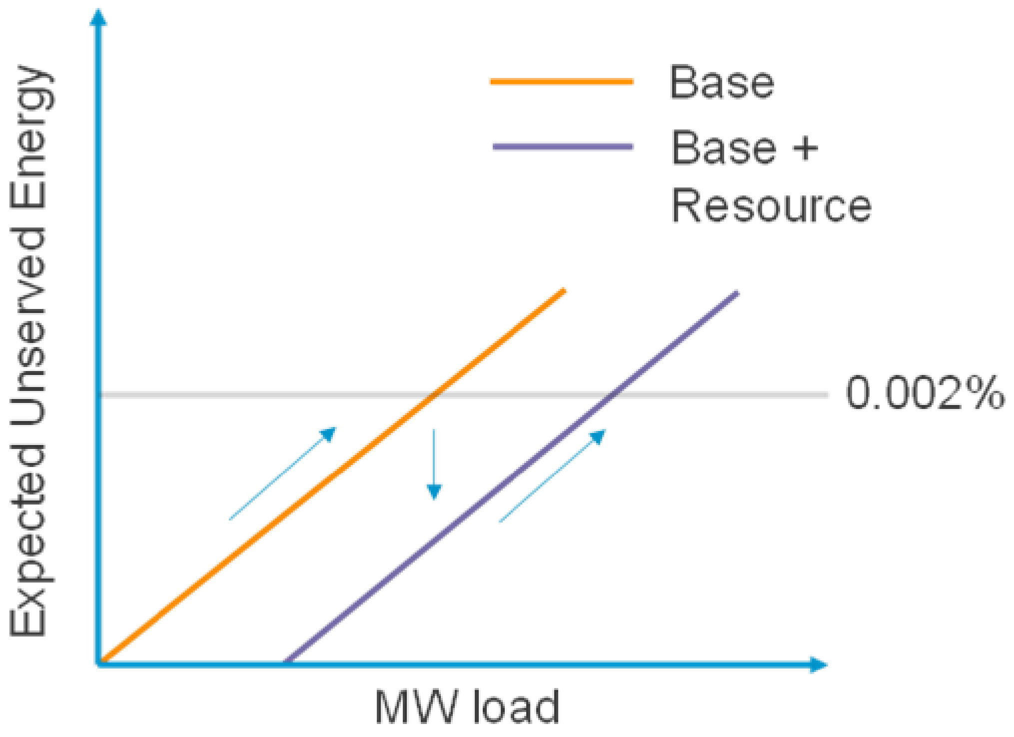
1. take a historical load profile and adjust it so that it reflects the underlying demand before any loss of load or DSP dispatch[29];
2. determine the expected lost load (for example adjust load to derive 0.002% EUE, or the desired LOLE measure, or use the unadjusted EUE or LOLE) in a base case that does not include the candidate facility;
3. add the candidate facility to the base case;[30]
4. adjust load (using a flat profile and increment every interval with the same amount) until expected lost load is back to the same level as in the base case; and
5. calculate ELCC for the facility as the MW of load added.

[28] The ELCC method is familiar to WEM participants through prior work by the ERA and the Rule Change Panel.

[29] The load profile may also be adjusted for relevant expected future changes to the load such as projected increase in DPV or change in block loads.

[30] For intermittent generators, this means adding the facility's expected or historical generation profile to the base case,

Figure 25: ELCC method



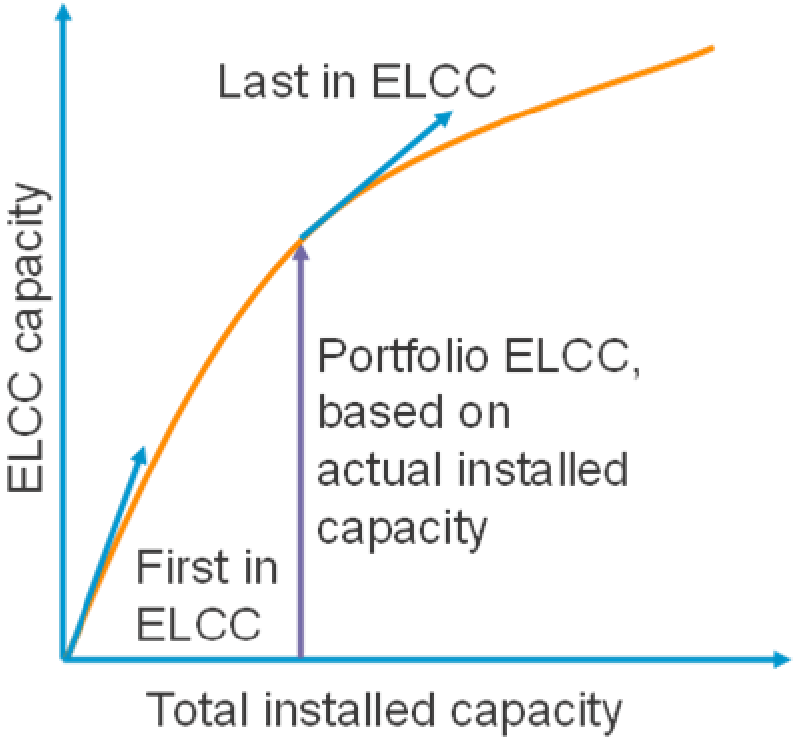
The ELCC for a facility that is 100% available at all times is the maximum output of the facility. The ELCC of a traditional thermal facility can be calculated without probabilistic modelling and is dependent on whether outages are included or excluded (see section 5.3).

A facility's ELCC can be affected by the characteristics of other facilities in the fleet. Where intermittent output is correlated, additional facilities of that type will contribute less and less to system reliability. For this reason, the ELCC for a particular facility will differ depending on whether it is assessed in the presence or absence of other similar facilities. For example, the first solar facility in a power system will have a very high proportion of its output contributing to meeting the reliability requirements. The twentieth large solar facility is much less likely to contribute, as there is already an oversupply of facilities generating during daylight hours. Similarly, as more wind farms are built in the same geographical area, the correlation between their outputs means that each subsequent MW contributes less to system reliability.

The "first-in ELCC" is the marginal ELCC of an individual intermittent facility in the absence of other intermittent facilities. The "last-in ELCC" is the marginal ELCC of a facility in the context of the whole fleet. The "portfolio ELCC" is the collective ELCC of a group of facilities (potentially the whole fleet) and can be greater or less than the sum of the first-in ELCCs or last-in ELCCs.

Figure 26 illustrates how the Facility ELCC can change depending on the characteristics of the fleet. This change can be positive or negative, depending on whether the facility being assessed complements the rest of the fleet.

Figure 26: First in and last in ELCC



To ensure that the total allocated ELCC matches the ELCC of the fleet as a whole, the first in and last in facility ELCCs can be used to allocate the fleet effect according to the “delta method” as follows.[31]

1. For each individual facility, calculate:
   a. the First-In ELCC, which is the ELCC of the individual facility excluding the other facilities (i.e. as if the individual facility was the first facility used to meet system demand); and
   b. the Last-In ELCC, which is the ELCC of the individual facility including the other facilities (i.e. as if the other facilities have already reduced demand);
2. Determine the Interactive Effect as the fleet ELCC less the sum of all facilities’ Last-In ELCCs;
3. Determine the Delta for each facility as its First-In ELCC less its Last-In ELCC;
4. For each facility, determine its Interaction Effect Share as the facility’s Delta multiplied by the Interactive Effect and divided by the sum of all Deltas; and
5. For each facility determine the ELCC as its Last-In ELCC plus its Interaction Effect Share.

This can be represented by the following equation:

$$ELCC_i\ (each\ resource) = LI_i + (P - \sum_{j=1}^{n} LI_j)(\frac{LI_i - FI_i}{\sum_{j=1}^{n} LI_j - FI_i})$$

Where:

- LI_i is the Last-In ELCC of Facility i

[31] See Energy and Environmental Economics, Inc., Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy

- FI_i is the First-In ELCC of Facility i
- P is the Portfolio ELCC

Depending on the load shape and the volatility of the facility's output, ELCC results can be driven by a facility's performance during a small number of intervals (those with the highest likelihood of unserved energy). For example, if a facility is not available at system peak, then increasing load in that period will have a 1:1 relationship with unserved energy. If the profiles for demand and facility generation are taken from too short a period, the period may not include any relevant system stress events, and the facility's ELCC would be calculated based on its performance in non-peak intervals.

Today, solar facilities can contribute in some periods where there is potential for lost load. Over time, the increase in behind the meter solar PV will mean that there is no longer any chance of lost load while the sun is up, meaning that by 2050, the first-in and last-in CRC of all solar projects is likely to be zero.

The ELCC of wind facilities will change over time as the peak shifts, and as the intervals with likelihood of lost load change. Performance in the system stress events during evening peak is expected to remain the largest driver of ELCC.

The main concern with the ELCC method is volatility of the results for windfarms – that is, the method considers all hours in the reference timeframe, but the inherent volatility of the output of wind farms at peak periods means that the results are driven by only a small number of intervals. If the facility output is volatile, then using a small number of intervals has the potential to under- or over-estimate expected facility performance. Over time, this would likely average out, but could continue to be volatile from year-to-year. Because the WEM experiences only a few system stress events over multiple years, a single stress event being added or removed from the reference period can markedly affect the ELCC of a facility with volatile output.

Non-probabilistic method

Expanding the number of intervals driving CRC allocation would reduce volatility, but could include performance in periods that do not represent performance of facilities in stress situations. The current RLM attempts this, but the periods used are not representative of stress situations.

The RCMRWG proposed that a non-probabilistic method could reduce this uncertainty, with one of the group members suggesting[32] that it could be calculated as follows:

1. take a set of historical load data over five years, adjusted to remove the effects of any load shedding or DSP dispatch;
2. select the 20 days with the highest demand in each year, and then the 10 intervals from each of those days with the highest likelihood of unserved energy – for example, 4:00 pm to 9:00 pm – for a total of 1000 intervals (around 2.3% of intervals);
3. find the mean output of each facility in the selected intervals;
4. de-rate the output to reflect the variability of the facility; and
5. set the CRC for the facility as the de-rated mean output in the selected intervals.

[32] See: https://www.wa.gov.au/system/files/2022-07/RCMRWG%202022_07_21%20-%20Slides%20from%20Alinta%27s%20Presentation_0.pdf

This approach is conceptually simple, but risks basing the CRC for intermittent generators on their performance during intervals that do not reflect system stress conditions. It also does not account for any correlation between facility outputs.

It is considered that the method can be refined to better approximate system stress periods by using the highest stress intervals across the entire period rather than for each year individually, and to account for correlation between facility outputs by using demand minus intermittent generation, as follows:

1. take a set of historical load data over five years (adjusted to remove effects of any load shedding or DSP dispatch, and adjusted to reflect penetration of solar PV generation in the reference year);
2. for each facility:
    a. sort the intervals in order of load minus all intermittent generation plus the output of the facility assessed to produce a multi-year lowest-scheduled-generation (LSG) duration curve[33];
    b. select the highest intervals (for example, the top 5%) as representative of system stress events; and
    c. find the facility output (adjusted for any curtailment) during those intervals;
    d. sort in order of facility injection;
    e. find output at a given percentile output in those intervals; and
    f. set the CRC of the facility at the maximum of that value and zero.

Under either of these methods, the total quantity of CRC allocated will be sensitive to both the facility output percentile used and the load percentage used. Unlike the ELCC method, the allocation to individual facilities does not consider the overall ability of the generation fleet to serve load.

Alternative hybrid ELCC method

The RCMRWG also discussed an alternative hybrid ELCC method, whereby the overall fleet capability was calculated using the ELCC method, and this total ELCC is allocated according to a non-probabilistic method. Another member of the group proposed[34] that this be calculated as follows:

1. take load and facility output data for each of the seven previous capacity years;
2. calculate the annual fleet ELCC for each year;
3. determine the fleet ELCC as the mean of the annual fleet ELCC values;
4. select the 12 days from each year with the highest demand and then the four intervals with the highest demand in each of those days, for a total of 240 intervals (around 0.5% of intervals);
5. for each facility, calculate the facility performance level as the mean of its output in the selected intervals;

[33] The output of the facility in question would be added back to the load, as otherwise the helpful contribution of the facility could shift the 'peak' periods to its disadvantage.

[34] See: https://www.wa.gov.au/system/files/2022-07/RCMRWG%202022_07_21%20-%20Slides%20from%20Collgar%27s%20Presentation_0.pdf

6. calculate scaling factor R as the fleet ELCC divided by the sum of the facility average performance levels; and
7. for each facility, determine CRC as the scaling factor multiplied by the facility average performance level.

This approach would ensure that the total CRC allocated does not exceed the overall ELCC calculated for the fleet.

Analysis by the group member who proposed this hybrid method indicates that:

- the overall variance in the total fleet allocation would be less than for the delta method;
- the year-to-year variation in individual facility allocations would be somewhat muted; and
- the method is relatively insensitive to changes in the selection of peak intervals.

This approach would ensure that the total CRC allocated does not exceed the overall ELCC calculated for the fleet. However, partitioning data by year will give undue weight to non-stress intervals in years where the peak demand is low, and using the load alone ignores the effect of correlation between facility outputs.

It is considered that the method could be refined to address these issues as follows:

1. take load and facility output data for the five previous capacity years;
2. calculate the fleet ELCC using the load trace for the whole period to avoid giving undue weight to non-stress intervals in years where the peak demand is low;
3. for each facility, sort the load trace in order of operational demand less all intermittent generation output plus the output of the facility assessed to produce a multi-year LSG duration curve [35];
4. for each facility, select the highest intervals (for example, the top 0.5%) as representative of system stress events;
5. for each facility, calculate the facility average performance level as the higher of zero and the mean of its output in the selected intervals;
6. calculate scaling factor R as the fleet ELCC divided by the sum of facility average performance levels; and
7. for each facility, determine CRC as the scaling factor multiplied by the facility average performance level.

This approach would ensure that the total CRC allocated matched the fleet capability, and incorporate facility output correlation, while reducing some of the volatility in individual facility CRCs.

5.4.5 Discussion

It is considered that simple methods of CRC assessment remain appropriate for Capability Class 1 and 2 facilities[36], but that an alternative method may be appropriate for Capability Class 3 facilities.

[35] Again, the output of the facility in question would be added back to the load, as otherwise a helpful contribution from the facility could shift the ‘peak’ periods to its disadvantage.

[36] Given temperature trends in the SWIS over the last decade, the reference temperature of 41 degrees may no longer be the appropriate benchmark. This will be considered in stage 2 of the RCM review.

EPWA will continue quantitative analysis to assess options to improve the proposed CRC methods, using common assumptions and inputs to ensure comparability, and propose a preferred option during stage 2 of the RCM Review. The selected method must reflect actual contribution to system reliability, and EPWA will seek to balance this with the need to provide certainty for investment. This assessment will be conducted in consultation with the RCMRWG, and EPWA will endeavour to align input data, calculation models, and outputs as far as possible.

It is considered that the IRCR methodology needs to be adjusted to better align with the intervals used to determine CRC allocation. The IRCR methodology will be considered in the next stage of the RCM review.

Conceptual Design Proposal 17:

- The methodology to assign CRC to facilities in each of the different Capability Classes will differ by class as follows:
  - Class 1: Expected output at projected 10% POE peak ambient temperature;
  - Class 2: Expected output at projected 10% POE peak ambient temperature, adjusted for required availability duration; and
  - Class 3: To be confirmed in stage two of the RCM review.

Consultation Questions:

(17)(a) Do stakeholders support using a different methodology to assign CRC to facilities in each Capability Class.

(17)(b) Do stakeholders support the proposed methodology to assign CRC to facilities in Capability Class 1?

(17)(c) Do stakeholders support the proposed methodology to assign CRC to facilities in Capability Class 2?

(17)(d) Do stakeholders prefer one of the three identified methodologies for assigning CRC to facilities in Capability Class 3 and what are the reasons for the preference?

Appendix A. RCM Review Current Timetable

<table>
<tr><th>Task/Milestone</th><th>Timing</th></tr>
<tr><td colspan="2">Stage 1</td></tr>
<tr><td>Literature review of RCM arrangements in other jurisdictions.</td><td>March 2022</td></tr>
<tr><td>Determine the requirements for capacity needed to achieve the purpose of the RCM, by defining:
• what system stress situations appear in the WEM (currently and forecast for 2030);the capacity requirements needed to achieve the reliability target; and
• which system stress situations can/should be addressed through the RCM.</td><td>May 2022</td></tr>
<tr><td>Review the Planning Criterion to ensure it reflects the purpose of the RCM and the reliability target, including assessing whether to use ICAP or UCAP is best suited to determine the capacity value in the SWIS.</td><td>June 2022</td></tr>
<tr><td>Consultation with the MAC and RCMRWG and stakeholder workshops</td><td>January – July 2022</td></tr>
<tr><td>Develop high-level approaches for assigning CRC and setting of the BRCP considering the revised Planning Criterion.</td><td>July 2022</td></tr>
<tr><td>Consultation on Stage 1 with the MAC and RCMRWG and stakeholder workshops.</td><td>August – September 2022</td></tr>
<tr><td colspan="2">Stage 2</td></tr>
<tr><td>Develop a high-level approach to reflect the design developed under Stage 1, including:
• preferred method for CRC allocation for intermittent facilities
• the Relevant Demand Methodology;
• outage scheduling;
• the refund mechanism;
• Reserve Capacity Testing;
• determination of IRCR; and
• assessment of whether any transitional measures are needed, and if so, develop the transitional measures.
This will include consultation on the approaches with the MAC and RCMRWG</td><td>December 2022</td></tr>
<tr><td>Publish a consultation on the outcomes of Stage 2 via the release of a Consultation Paper and a request for stakeholder submissions.</td><td>January 2023</td></tr>
<tr><td colspan="2">Stage 3</td></tr>
<tr><td>Develop the detailed design and Rule Change Proposals for the concepts developed under Stages 1 and 2.</td><td>February-April 2023</td></tr>
<tr><td>Consultation paper(s) on the detailed RCM design and Rule Change Proposals and a request for stakeholder consultation.</td><td>May 2023</td></tr>
</table>

Task/Milestone	Timing
Publish a final Information Paper on the proposed detailed revised RCM design.	June 2023
Submit Rule Change Proposal for consideration and approval by the Coordinator and Minister.	June 2023

Appendix B. Modelling Approach

Resource adequacy modelling was conducted in support of the RCM Review to:

- simulate facility dispatch to meet projected demand in 2022, 2030 and 2050;
- characterise system stress in the SWIS;
- assess how the current and future fleet contributes to or mitigates the stresses; and
- identify appropriate resource adequacy measures for the SWIS and consequential changes to the Planning Criterion.

Modelling focused on generation adequacy by extending the fleet to add sufficient capacity to achieve approximately 0.002% EUE, and then observing the timings and durations of system stress events.

B.1 Modelling Tools

Two modelling tools were used:

- CAPSIM, to assess system reliability; and
- WEMSIM, to determine the economic feasibility of various technologies under different CRC allocation methodologies and BRCP assumptions.

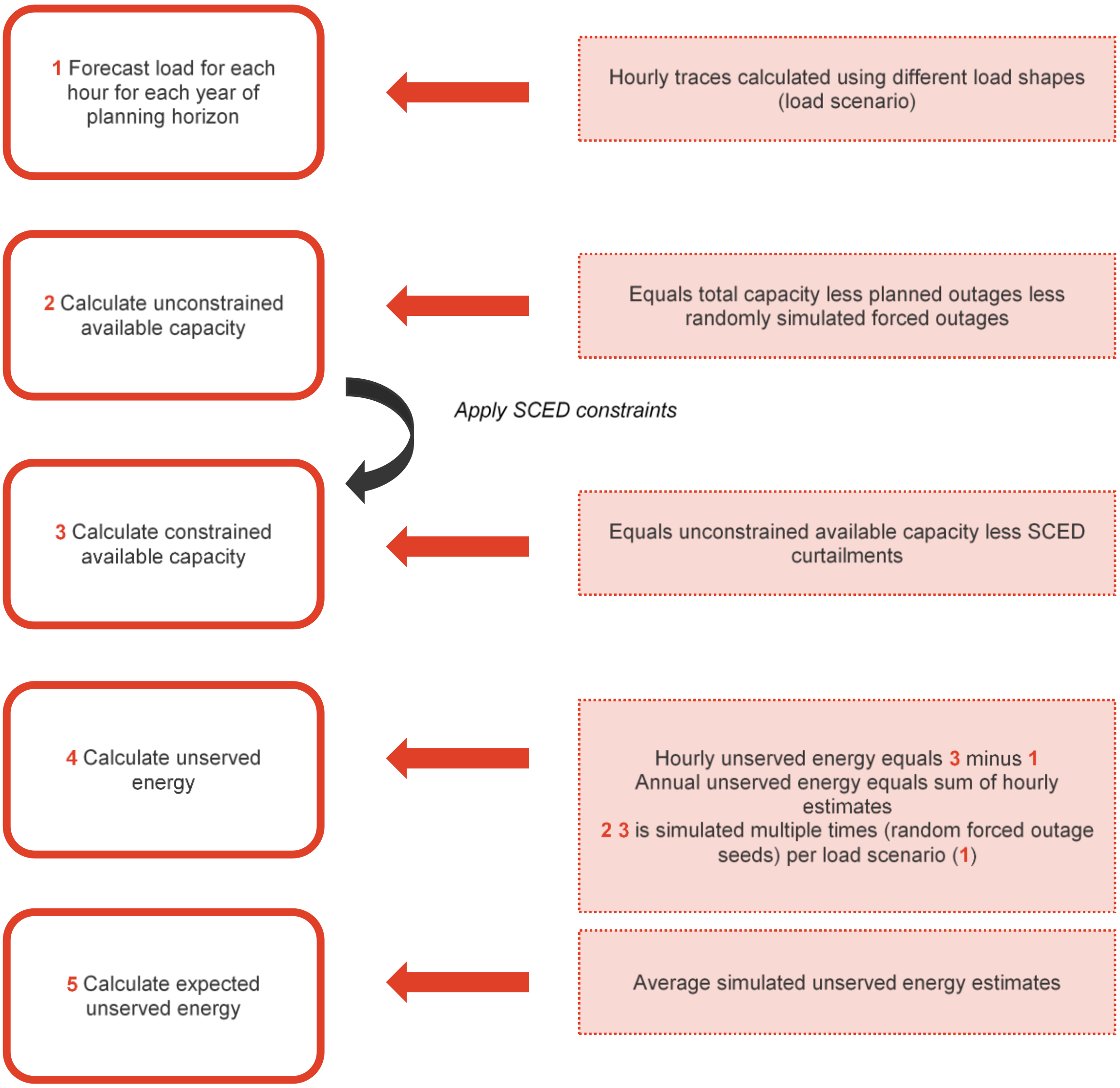
B.1.1 CAPSIM

CAPSIM is a bespoke model built in Python using open-source NumPy and Pandas packages, which simulate and compare the available capacity for each hour in a stipulated period and compares it to the corresponding load. This model was developed for the context of the WEM Reliability Assessment and delivers a large amount of statistical power to capture the increasing role of intermittent generation (and in the future, ESRs) in the WEM. CAPSIM runs hour by hour discretely and not chronologically. The model performs a Monte-Carlo analysis of different system characteristics, focusing on variability in forced outage rates, and accounting for intermittent generation profiles, load profiles, and network constraints. Unserved energy occurs whenever load is less than total available capacity in a period.

CAPSIM is significantly faster than dispatch optimisation models because it does not optimise dispatch or create a merit order, which is not necessary in the context of unserved energy. CAPSIM is run over multiple iterations with varying random number seeds for forced outages, to generate a probability distribution of unserved energy and to estimate EUE.

As shown in Figure 27, the hourly demand for the forecast period is calculated based on historical data. The different load shapes from the previous years are used to develop a forecasted load curve. The unconstrained capacity is the total capacity available in the system while taking into account planned outages and forced outages. Forced outages are randomly simulated based on historical outage data. The constrained capacity is calculated from the unconstrained capacity by accounting for transmission constraints. Finally, the model calculates the unserved energy during periods when the total generating capacity is less than the total demand, leading to unserved energy. The total EUE is the average of the unserved energy during the forecast period.

Figure 27: CAPSIM Overview



B.1.2 WEMSIM

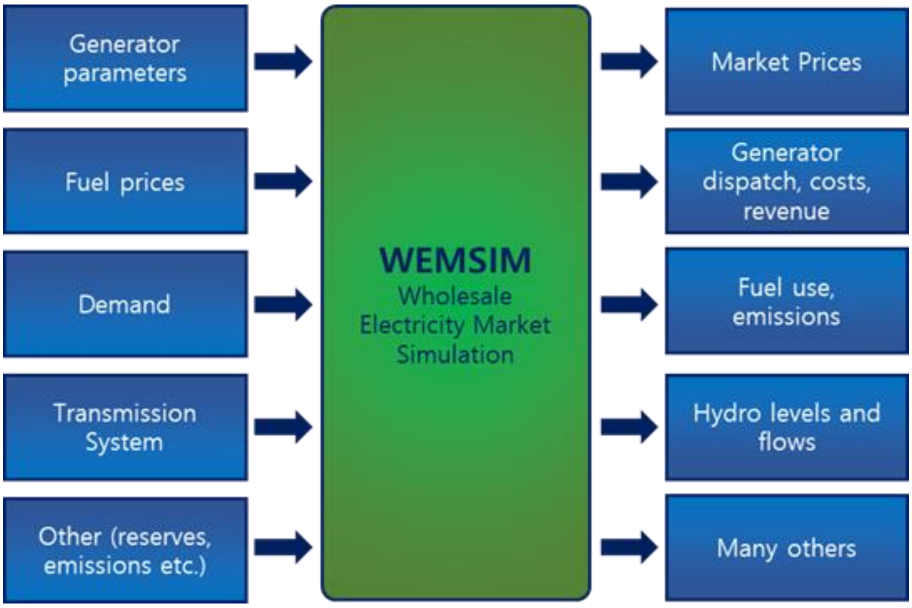
WEMSIM (Wholesale Electricity Market SIMulation) is an analytical dispatch planning and analysis tool that simulates the dispatch of generation resources in a multi-regional transmission framework. WEMSIM is an optimization engine based on linear and mixed integer (MIP) programming. WEMSIM simultaneously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

WEMSIM co-optimises energy dispatch and reserve provision using:

- generation facility data such as capacity, outage rates, ramp rates, heat rates and cost information – fuel, variable operation, and maintenance costs (VOM), fixed operation and maintenance (FOM);
- transmission data, either via the specification of thermal limits or generic constraints (as used for the WEM); and
- reserve requirement and provision data.

WEMSIM is used for analysing optimum dispatch, fuel use, system security, market price impacts and emissions from the electricity system.

Figure 28: WEMSIM Overview

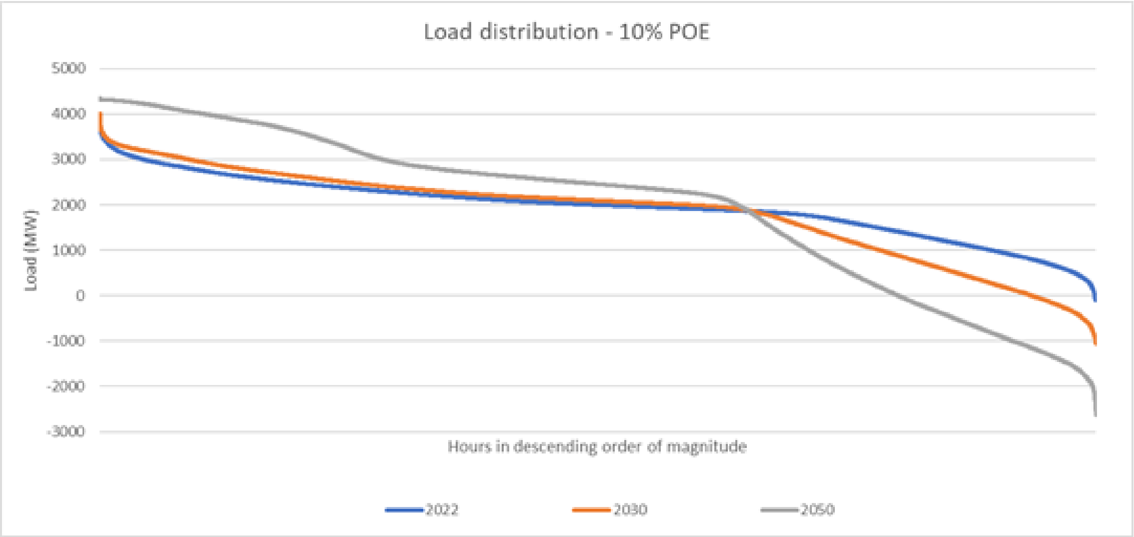


B.2 Demand Forecast

Modelling used the demand forecasts from AEMO's 2021 ESOO[37] for 2022 and 2030 and extrapolated to 2050 assuming there will be some optimisation of electric vehicle charging. Modelling considered both the 50% POE load forecast and the 10% POE load forecast, to understand how system stress events differ depending on the load.

Modelled load duration curves for the 10% POE case are shown in Figure 29.

Figure 29: Load Duration Curves



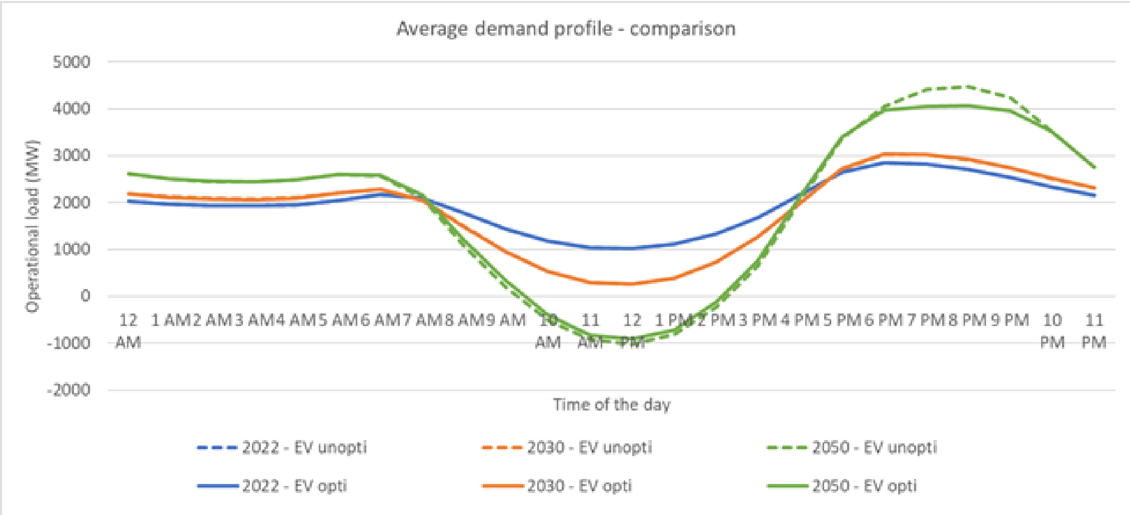
Because the modelling is focused on generation adequacy, the demand traces reflect operational demand before any measures to respond to low or negative operational demand. In these periods, storage and any other demand increase available in the market would be dispatched to soak up

[37] https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo

the excess generation from unregistered behind the meter facilities. As a last resort, AEMO may conduct emergency curtailment of distributed solar resources.

Without electric vehicle (EV) optimisation, the 2050 demand profile would have a higher and sharper peak, as shown in Figure 30.

Figure 30: Average Demand Profile with and without Electric Vehicle Optimisation



Modelling did not include any potential effects of new consumer incentives to increase demand in the middle of the day (such as tariff adjustments, off-market retailer programmes or the orientation of new rooftop solar installs).

B.3 Build and Retirement Scenarios

The future state of the SWIS generation fleet is uncertain. The modelling therefore considered several potential retirement and build scenarios, to understand system stress in a variety of possible futures.

The underlying assumptions behind retirement of existing generators is that all coal, gas, and distillate units retire by 2050, in accordance with the Western Australian Government's stated goal of net-zero carbon by 2050.

- Scenario 1 – Muja retires on schedule; other coal and gas remains until at least 2030:

  In this scenario, all fossil fuelled power plants except the Muja units remain available in 2030, and all other fossil fuelled plants retire by 2050.

- Scenario 2 – All baseload retires by 2030:

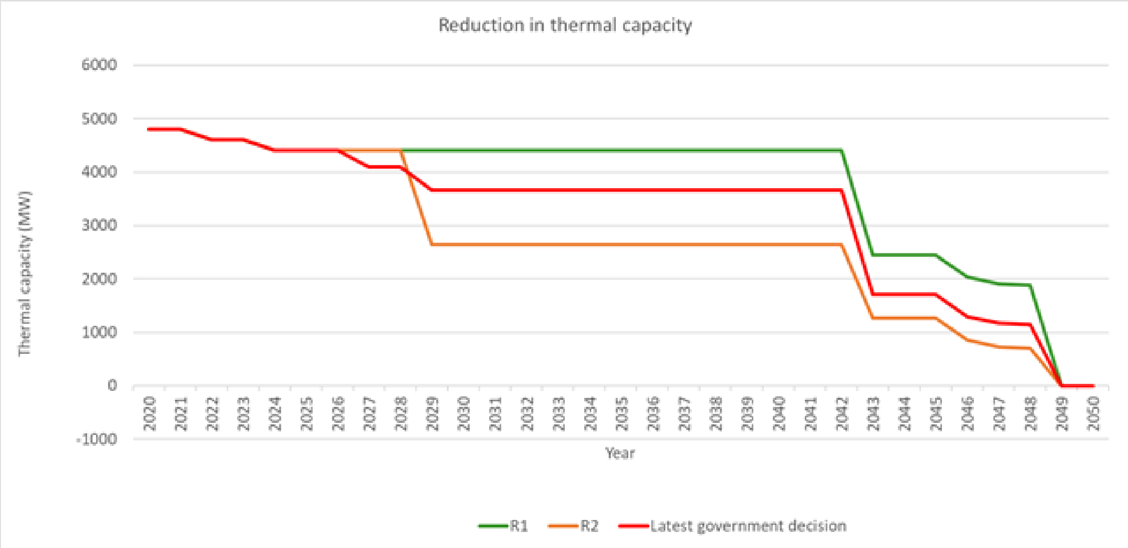
  In this scenario, there is a rapid decarbonisation where all baseload generators (coal and CCGT) exit the market by 2030. Mid merit and peaking gas and liquid generation retire by 2050.

Table 3: Retirement scenarios

Scenario	2022	2030	2050
R1	Current capacity mix	Muja retires as scheduled	All thermal plant retired
R2		All thermal baseload plant retires	

The modelling was conducted before the announcement of additional Synergy facility retirements by 2030.[38] The three retirement profiles are shown in Figure 31.

Figure 31: Retirement profiles



It is not yet clear what type of facility will replace the retiring thermal generation. The modelling considered three scenarios for the 2050 fleet:

- Sufficient low-emission generation (wind and solar) to meet total energy demand, with storage available to ensure that energy can be shifted in time to when it is needed. Storage in this context includes any kind of technology that can store power.
- More low emission generation than needed to meet total energy demand. This helps compensate for the intermittent nature of these renewables, reducing the need for large storage facilities.
- Sufficient low emission generation to meet total energy demand, with a combination of storage and a new firm low-emission technology such as green hydrogen or nuclear fusion.

These scenarios are not intended to reflect any particular form of technology but are intended to compare three main types of capacity, intermittent, storage, and firm.

Table 4: Build scenarios

<table>
<tr><th>Scenarios</th><th>2022</th><th>2030</th><th>2050</th></tr>
<tr><td>S1</td><td rowspan="2">Current capacity mix</td><td rowspan="2">New capacity as required in line with respective 2050 targets</td><td>Sufficient PV + wind by 2050 to meet energy requirement
Large storage capacity
Some demand flexibility</td></tr>
<tr><td>S2</td><td>PV + Wind overbuild by 2050 reducing amount of storage required
Less storage capacity
Large demand flexibility</td></tr>
</table>

38 https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/06/State-owned-coal-power-stations-to-be-retired-by-2030.aspx

Scenarios	2022	2030	2050
S3			Sufficient PV + wind by 2050 to meet energy requirement Green H2 thermal Some storage Some demand flexibility

The overall findings are consistent across scenarios. While the details of timing change, the overall conclusions are similar.

B.4 Timing of Expected Unserved Energy

Figure 32 through Figure 35 show the periods with highest likelihood of unserved energy in 2030 and 2050 under the 10% and 50% POE load forecasts.

Figure 32: LDC and Unserved Energy Events – 2030, 10% POE

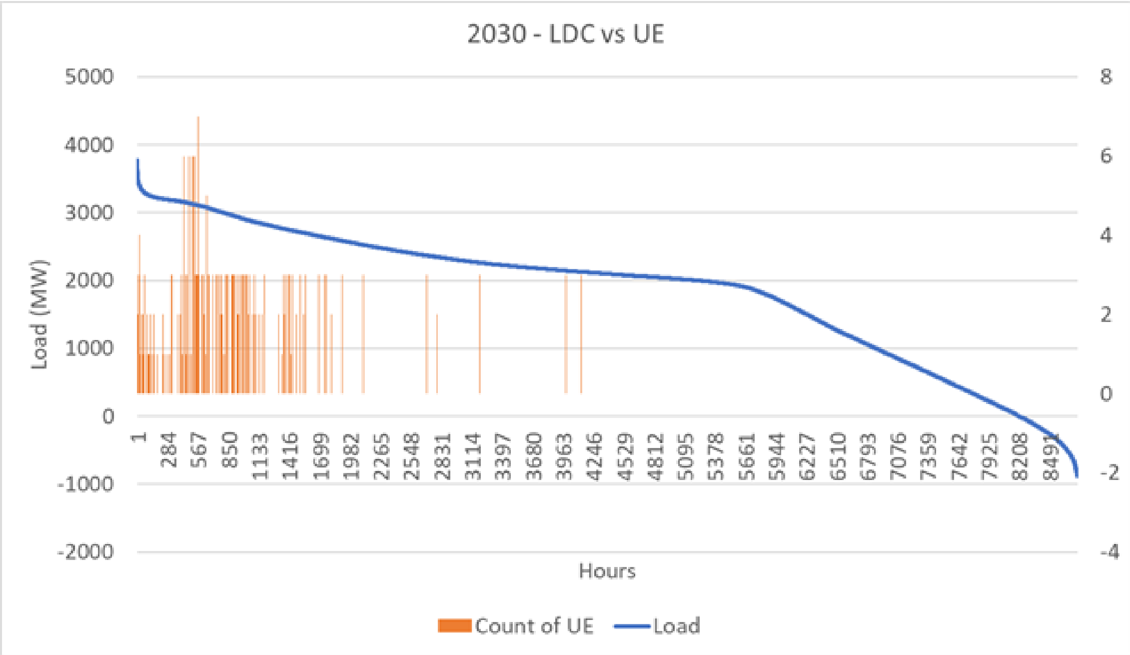


Figure 33: LDC and Unserved Energy Events – 2050, 10% POE

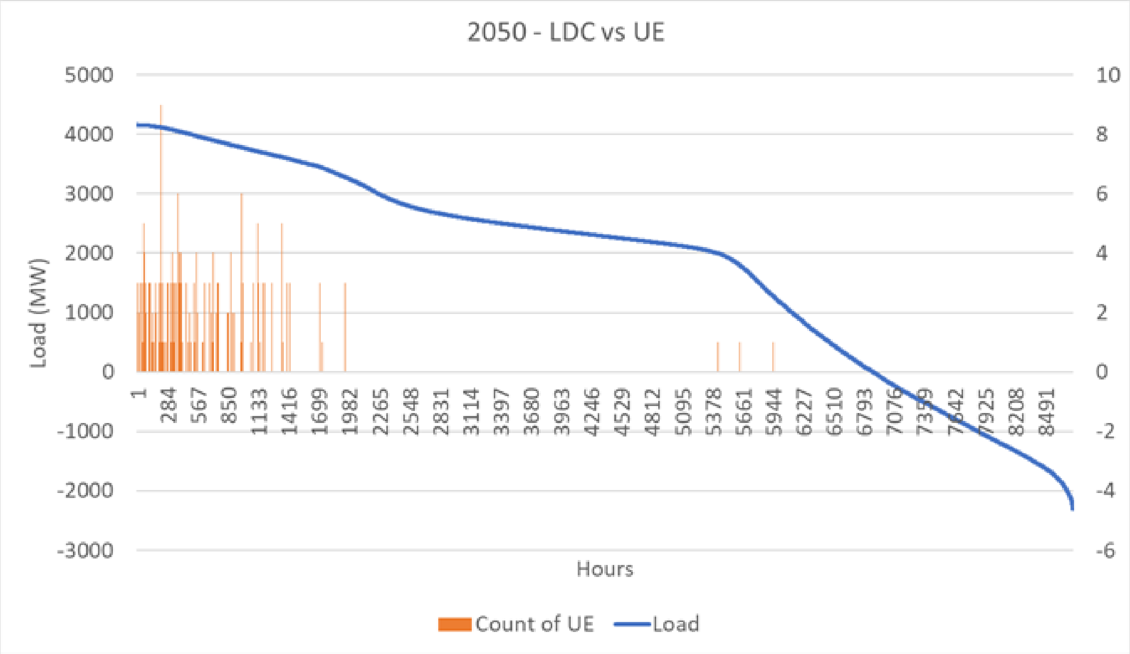


Figure 34: LDC and Unserved Energy Events – 2030, 50% POE

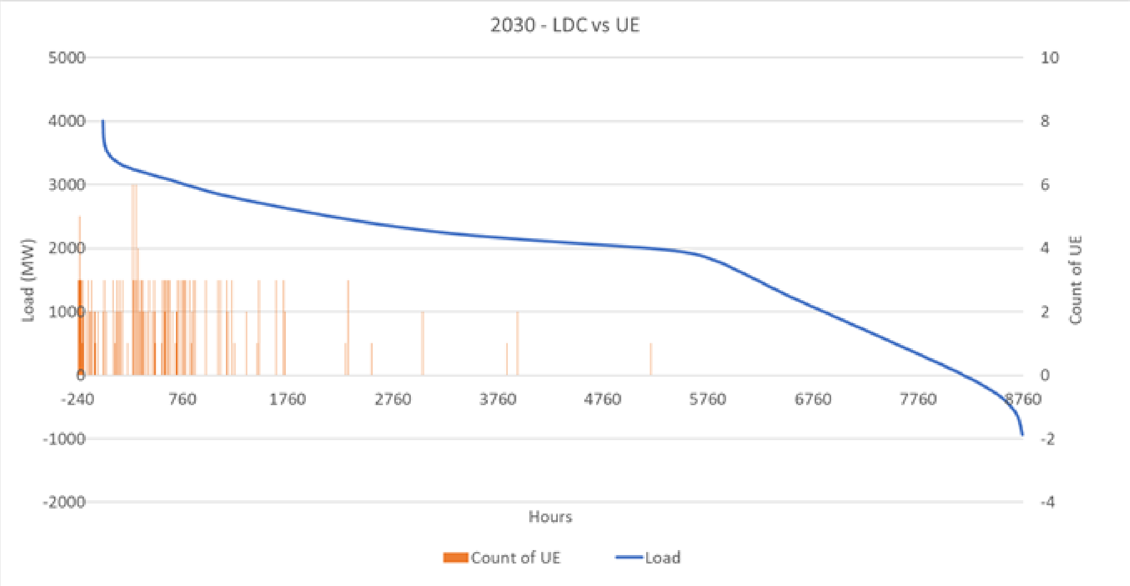
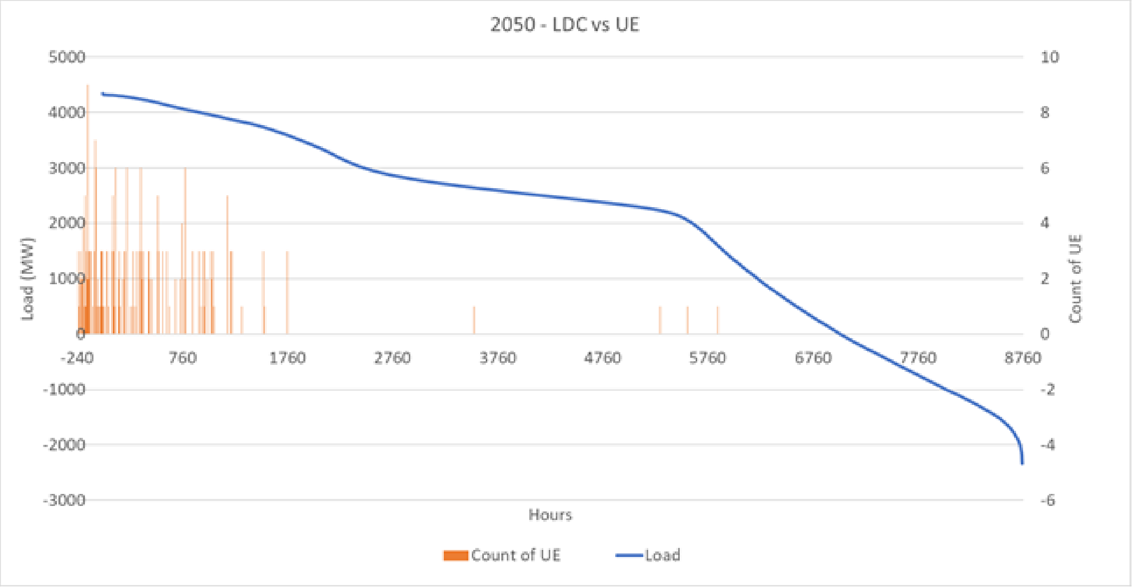


Figure 35: LDC and Unserved Energy Events – 2050, 50% POE



Appendix C. Estimated UCAP Capacity

Table 5 shows an example calculation of Capacity Credits under the UCAP method, using publicly available outage and service data for 2012 to 2022. Table 5 does not account for potential removal of uncharacteristic outages, nor for forced outages that were recorded outside of running hours.

Table 5: Outage adjusted Capacity Credits

Facility	Forced Outage Rate 2012-2022 (FOR)	% Of hours in service	FOR/Service Hours (EFORd)	Nameplate Capacity	CC 2022/23	FOR Adjusted CC	EFORd Adjusted CC
ALCOA_WGP	5.15%	61.80%	8%	38.5	26	24.7	23.8
ALINTA_PNJ_U1	0.43%	51.18%	1%	143	142.45	141.8	141.3
ALINTA_PNJ_U2	1.17%	50.73%	2%	143	142.45	140.8	139.2
ALINTA_WGP_GT	0.28%	7.13%	4%	212	196	195.4	188.3
ALINTA_WGP_U2	0.42%	7.57%	6%	212	196	195.2	185.0
BW1_BLUEWATERS_G2	1.17%	63.71%	2%	229	217	214.5	213.0
BW2_BLUEWATERS_G1	6.50%	65.17%	10%	229	217	202.9	195.4
COCKBURN_CCG1	1.85%	15.19%	12%	240	240	235.6	210.8
COLLIE_G1	1.48%	43.97%	3%	340	317.2	312.5	306.5
KEMERTON_GT11	0.11%	3.67%	3%	156	155	154.8	150.2
KEMERTON_GT12	0.11%	3.58%	3%	156	155	154.8	150.3
KWINANA_GT2	1.40%	77.69%	2%	100	98.5	97.1	96.7
KWINANA_GT3	2.26%	73.83%	3%	100	99.2	97.0	96.2
MUJA_G6	5.50%	38.78%	14%	193	193	182.4	165.6
MUJA_G7	4.28%	45.41%	9%	227	211	202.0	191.1
MUJA_G8	4.12%	46.03%	9%	227	211	202.3	192.1
NAMKKN_MERR_SG1	0.46%	0.46%	99%	86	82	81.6	0.5
NEWGEN_KWINANA_CCG1	0.61%	50.75%	1%	338.8	334.8	332.7	330.8
NEWGEN_NEERABUP_GT1	0.30%	10.70%	3%	342	330.6	329.6	321.3
PERTHENERGY_KWINANA_GT1	1.88%	9.90%	19%	120	109	106.9	88.3
PINJAR_GT1	0.16%	2.96%	5%	37.4	31	31.0	29.4
PINJAR_GT10	3.29%	23.79%	14%	116.4	110.5	106.9	95.2
PINJAR_GT11	1.30%	29.95%	4%	123.4	124	122.4	118.6
PINJAR_GT2	0.22%	2.34%	9%	37.4	30.5	30.4	27.7

Facility	Forced Outage Rate 2012-2022 (FOR)	% Of hours in service	FOR/Service Hours (EFORd)	Nameplate Capacity	CC 2022/23	FOR Adjusted CC	EFORd Adjusted CC
PINJAR_GT3	0.43%	2.48%	17%	38.34	37	36.8	30.6
PINJAR_GT4	2.99%	4.41%	68%	38.34	37	35.9	11.9
PINJAR_GT5	0.35%	2.56%	14%	38.34	37	36.9	31.9
PINJAR_GT7	0.19%	2.85%	7%	38.34	37	36.9	34.6
PINJAR_GT9	1.47%	22.57%	6%	116.4	111	109.4	103.8
PRK_AG	0.79%	5.39%	15%	68	59.748	59.3	51.0
STHRNCRS_EG	9.27%	39.06%	24%	23	21.012	19.1	16.0
TESLA_GERALDTON_G1	0.05%	2.34%	2%	9.999	9.999	10.0	9.8
TESLA_KEMERTON_G1	0.00%	1.21%	0%	9.9	9.9	9.9	9.9
TESLA_NORTHAM_G1	0.08%	0.16%	51%	9.9	9.9	9.9	4.9
TESLA_PICTON_G1	0.13%	0.55%	24%	9.9	9.9	9.9	7.5
TIWEST_COG1	1.53%	88.71%	2%	42.1	36	35.4	35.4

Appendix D. Economic Modelling Results

D.1 Introduction

The economic modelling simulates the impact of the high level design proposals on the profitability of new entrants in the WEM. This informs whether the proposed design changes will result in the required types of new capacity entering the market.

The results focus on the profitability of Battery Energy Storage Systems (BESS) entering the market.

D.2 Methodology

RBP's WEMSIM model of the WEM is used to forecast market dispatch and prices from 2022 to 2050. This model forecasts the following market outcomes:

- Facility dispatch for energy and ESS;
- Energy and ESS prices;
- Cost of generation and cost of energy used by facilities; and
- Net revenue.

The WEMSIM model includes:

- Daily and seasonal generation profiles for Wind and PV generation;
- Optimised charge/discharge profiles for ESS; and
- Start costs and minimum generation levels for key thermal plant.

A retirement and new build profile has been determined based on:

- Government announcements regarding retirement of coal facilities;
- Retirement of remaining thermal facilities based on assumed technical lifetimes and an assumption that all carbon-emitting facilities will be retired by 2050; and
- Sufficient Wind, PV and BESS new build to keep unserved energy below an acceptable level.[39]

Based on the WEMSIM results, a spreadsheet model calculates (on an annual basis):

- CONE for candidate new entry technologies, on a Gross and Net basis, for 3 future cost reduction profiles (based on CSIRO projections);
- BRCP;
- Capacity Credit allocation based on the ELCC delta method (ELCC values calculated in a separate model);
- RCM revenue for each facility; and
- Profitability of existing and new build facilities.

[39] Ideally below the 0.002% reliability criterion, but since WEMSIM is not a Monte Carlo model, this is not exactly achieved.

Multiple iterations of the model have been run, in which the levels of wind, PV and BESS have been refined to:

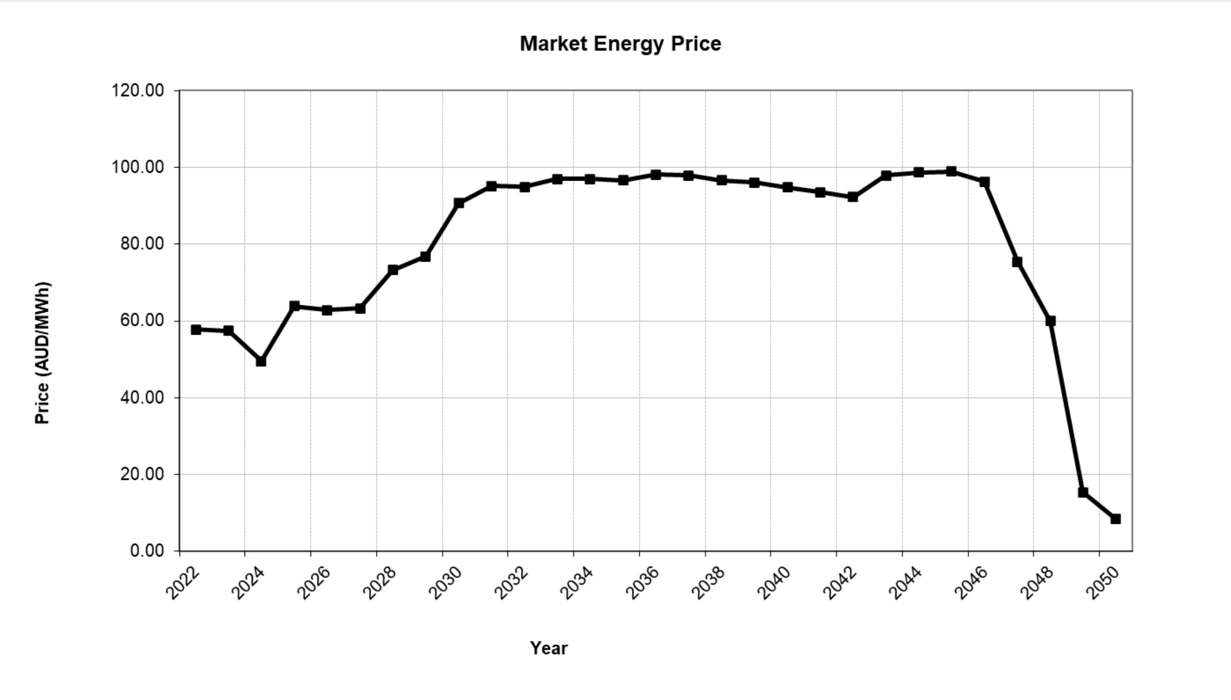
- Avoid unprofitable new build entering the market; and
- Keeping unserved energy below an acceptable level.

The following limitations of the modelling to date should be noted:

- Income from large-scale generation certificates (LGCs) is not included in the modelling. The assumption is that they are not extended and the purpose of the current modelling is to determine the type of new capacity entering the market with the RCM but in the absence of other incentives; and
- The modelling focuses on the existing peak capacity product, it does not provide for a separate flexible capacity target. As shown in Figure 8, additional capacity will be needed for this service, but this is not included in the current modelling. Income from a separate flexibility product is not assumed to increase the profitability of wind and PV.

D.3 Key Results

D.3.1 Market energy prices



Prices increase significantly up to 2030 with the retirement of the coal plants, resulting in prices being set by the gas OCGTs. This continues until the mid-2040s, when retirement of the remaining gas and distillate-fired plant, and extensive new build of PV, wind and BESS results in energy prices collapsing.

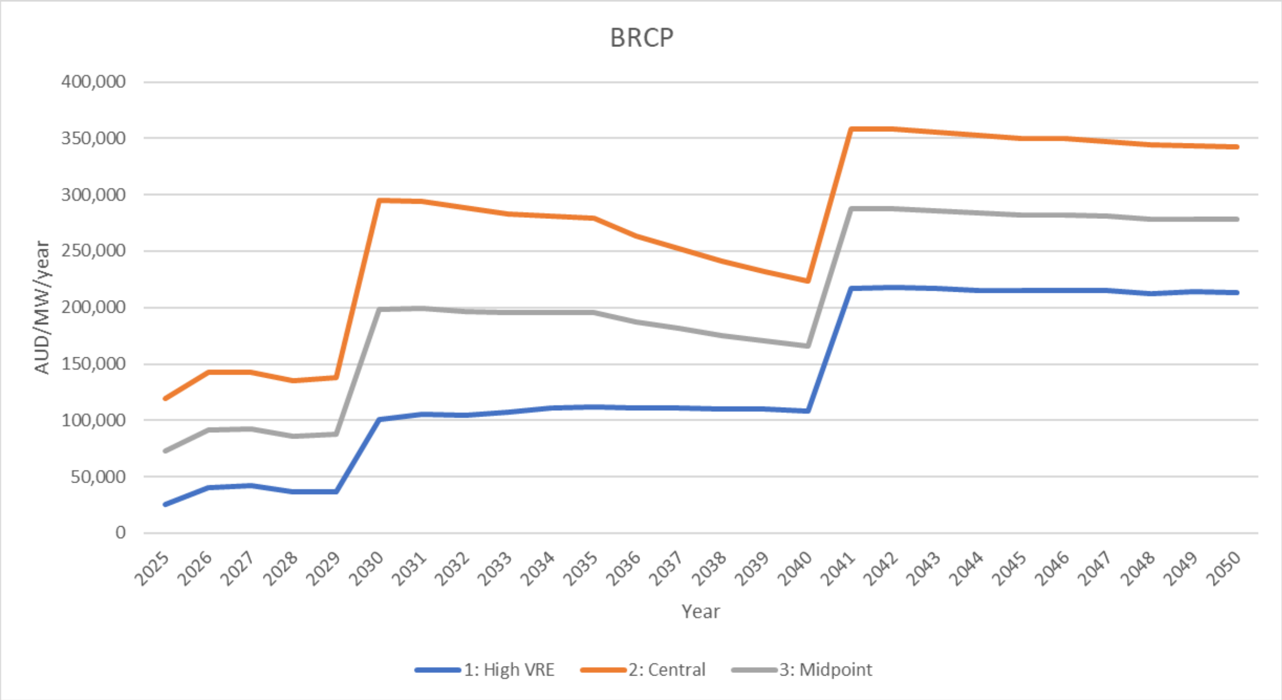
D.3.2 BRCP

The following chart shows projected BRCPs, on a net CONE basis, for three new cost projections:

- CSIRO 'High VRE';
- CSIRO 'Central'; and
- A midpoint between the above two.

This is calculated according to the proposed methodology, being the lesser of the net CONE of:

- A large OCGT, up to 2025 (assumed as the last date that OCGT is an acceptable new build technology);
- A BESS, sized as follows:
  - 4 hour duration from 2022 to 2029;
  - 8 hour duration from 2030 to 2040; and
  - 16 hour from 2041 to 2050.

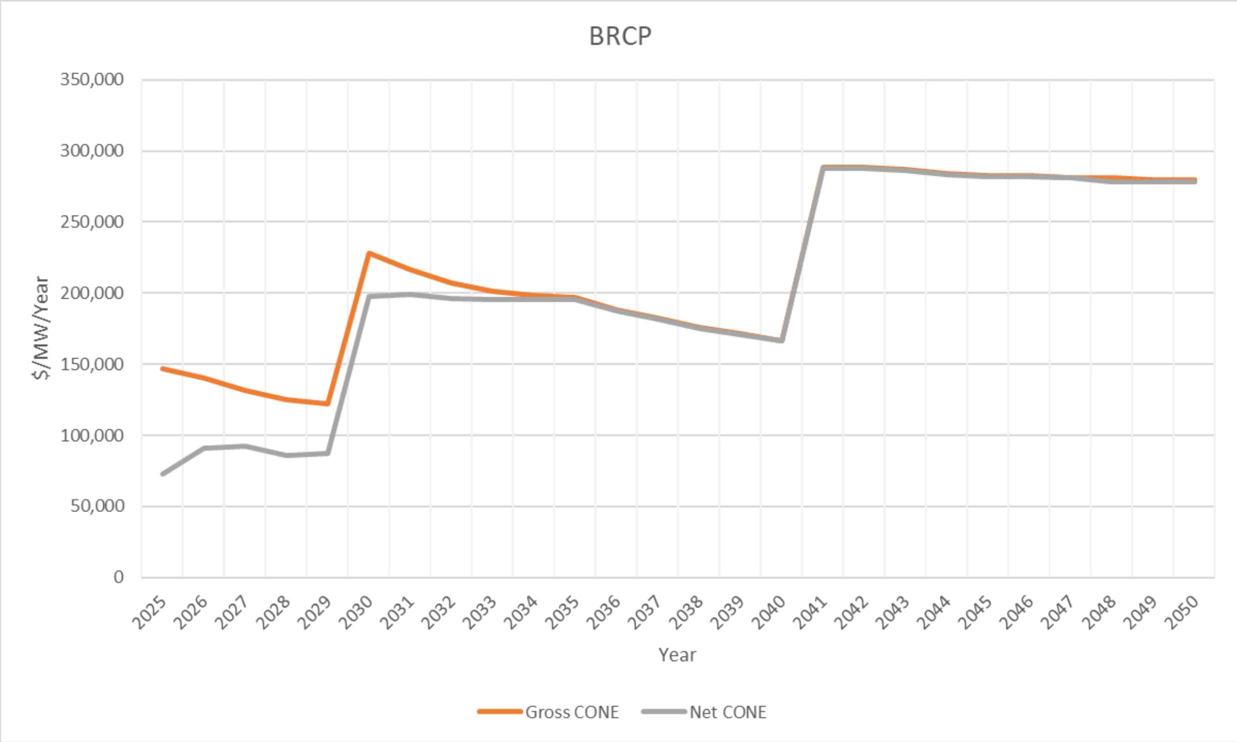


Key conclusions from these results are:

- In all years, BESS is profitable regardless of which technology is used to set the BRCP;
- The projected level of the BRCP is highly dependent on the assumed storage cost reduction profile; and
- BRCP increases significantly as the need for longer-duration storage results in the BRCP being set by longer duration batteries.

D.3.3 Net CONE vs gross CONE

The following chart show the impact of using net CONE vs gross CONE (using the ‘Midpoint’ cost reduction outlook):



The profitability of BESS results in much lower BRCP values using the net CONE basis during early years. As high levels of BESS new build are required in the later years to meet the reliability target, the per-unit profitability of BESS declines.

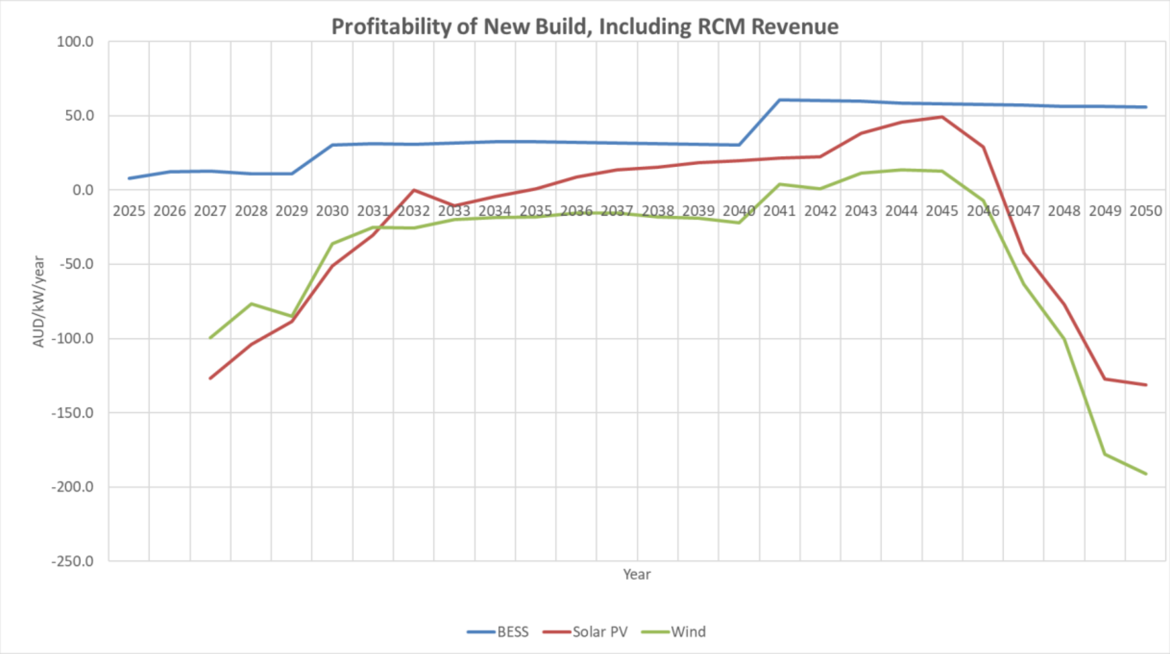
It should be noted that this result is very sensitive to new build assumptions. Increased intermittent generation build leads to greater utilisation and price spreads for BESS, increasing its net revenue and thus decreasing its net CONE. Zero net CONEs are possible under some realistic new build scenarios.

D.3.4 Profitability of new build

The profitability of new build measures whether the Net Revenue (Energy + ESS + RCM Revenue less variable costs) for new build is sufficient to meet the gross CONE (i.e. amortised capital costs and fixed O&M costs). A positive value indicates that the new build is financially viable, whereas a negative value indicates that it is not, and would not be built.

The following results are based on the following settings:

- BRCP set by OCGT/BESS on a net CONE Basis; and
- Midpoint cost reduction curve.



These results show that while BESS new build is adequately compensated by the market with these RCM settings, the case for PV and wind capacity is not so clear. While there is some positive profitability for PV and wind in later years, the experience in achieving this result over multiple iterations shows that this result is very sensitive to new build levels and is only achieved with an absolute minimum of PV and wind new build. Any overbuild can eliminate this profitability for PV and wind. This uncertainty could be a disincentive to invest in renewable generation.

The result could be adequate new build of BESS to perform the required load-shifting, but insufficient PV and wind capacity to provide the required energy. While all facilities receive the same market price when they are generating, several factors contribute to the low profitability of PV and wind:

- Using a net CONE basis for the BRCP results in low BRCP values for the early years;
- The ELCC delta method allocates very low levels of capacity credits to wind and PV. Therefore, these technologies only receive a fraction of their CONE through the RCM. The ELCC values for PV are close to zero, as they cannot contribute to system peak load; and
- It could be argued that the administered price curve, which limits the RCP to 1.3 time the BRCP, does not provide a sufficient scarcity price signal at times of low capacity to incentivise new build of renewables.

D.3.5 Conclusions

The modelling to date shows that while BESS new build is adequately compensated by the market with the proposed RCM settings, the RCM could be insufficient to incentivise sufficient new build of renewable generation to provide the energy required by the system as thermal capacity is retired.

Potential measures to ensure sufficient renewables build include:

- Extending the Renewable Energy Target (RETs) so that renewables have LGCs as an additional income source;
- Requiring BESS facilities that receive Capacity Credits to have contracts for sufficient renewable energy to meeting their energy charging requirements; or

- Modifying the administered price curve to provide a sufficient scarcity price signal. While reviewing the administered price curve is out of scope for this review, EPWA will consider this in a separate review.

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