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

Reserve Capacity Mechanism Review

Information Paper (Stage 2)

2 August 2023

Working together for a brighter energy future.

An appropriate citation for this paper is: Reserve Capacity Mechanism Review – Information Paper (Stage 2)

Energy Policy WA
Level 1, 66 St Georges Terrace
Perth WA 6000

Locked Bag 100, East Perth WA 6892
Telephone: 08 6551 4600

www.energy.wa.gov.au
ABN 84 730 831 715

Enquiries about this report should be directed to:

Email: EPWA-info@dmirs.wa.gov.au

Contents

Contents ii
Executive Summary iii
The Reserve Capacity Mechanism Review iii
Design Proposals and Rationale iii
1. Introduction 14
1.1 Background 14
1.1.1 The Performance of the RCM 14
1.1.2 The Need for Review 14
1.1.3 Scope of the Review 15
1.2 Purpose and Structure of this Paper 16
2. Stage 2 Review Outcomes 17
2.1 Individual Reserve Capacity Requirements 17
2.1.1 IRCR for Peak Capacity 17
2.1.2 IRCR for Flexible Capacity 19
2.2 Demand Side Programmes 21
2.2.1 DSP CRC 21
2.2.2 DSP Dispatch 23
2.3 Testing, Outages and Refunds 26
2.3.1 Reserve Capacity Testing 26
2.3.2 Outage Planning 28
2.3.3 Refunds 29
2.4 Other Matters 33
2.4.1 The EUE Target in the Planning Criterion 33
2.4.2 Determination of the BRCP Technology 34
2.4.3 Removal of Mandatory Expressions of Interest 35
Appendix A. Responses to the Stage 2 Consultation Paper 37

Executive Summary

The Reserve Capacity Mechanism Review

The Coordinator of Energy (Coordinator), in consultation with the Market Advisory Committee (MAC), is reviewing the 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 RCM 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 RCM products, the methods for assigning Certified Reserve Capacity (CRC) and the Benchmark Reserve Capacity Price (BRCP).[1]
- Stage two assessed how the outcomes of stage one affect the operation of other parts of the RCM, including the Individual Reserve Capacity Requirements (IRCR), Demand Side Programmes (DSPs), outage scheduling and the refunds mechanism.
- Stage three will deliver detailed design in the form of proposed rule amendments.

In July 2022, the Minister for Energy directed Energy Policy WA (EPWA) to investigate policy options for penalty regimes for high emission technologies. While not part of the original scope for the RCM Review, EPWA developed and analysed policy options in conjunction with the RCM Review. Consultation on the implementation of this policy is being conducted under the WEM Investment Certainty Review.[2]

The MAC constituted the RCM Review Working Group (RCMRWG) to support the RCM Review. More information on the RCM Review is available from the EPWA website,[3] 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.

Design Proposals and Rationale

The South West Interconnected System (SWIS) is undergoing a major transition. The nature of the demand profile and of the SWIS electricity supply sources are changing. This transition to a low emissions energy system is characterised by increasing levels of intermittent and distributed generation. As a result, new market design elements are needed to ensure secure and reliable electricity supply. While these new elements bring an increased cost in some cases, analysis suggests they are necessary to avoid significant and ongoing reductions in the reliability of electricity supply.

1 Alternative methods to assign CRC to intermittent generators were identified in stage one of the review and were assessed in stage two.

2 Wholesale Electricity Market Investment Certainty Review (www.wa.gov.au).

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

Stage 2 Review Outcomes

Review Outcome	Rationale
IRCR for Peak Capacity	
Review Outcome 1 IRCR requirements will continue to apply to a participant's contribution to load in high demand intervals during the Hot Season (December-March). Peak IRCR intervals will be selected as follows: (1) identify the 12 intervals from the previous Hot Season with the highest total sent out generation (SOG); (2) identify the trading days on which those intervals fell; (3) if fewer than three days are identified in step (2), identify the additional days in the Hot Season with the highest SOG outside the top 12 intervals to make a total of three days, rather than one or two days; (4) for each identified day, select: (a) the interval with the highest SOG; (b) all other intervals that are in the top 12 intervals; (c) if the intervals selected in steps (4)(a) and (4)(b) are less than three hours apart, all intervals between the intervals selected in steps (4)(a) and (4)(b); and (d) If fewer than three intervals have been selected, select the next highest SOG intervals on either side of the selected intervals to make up to three intervals. TDL/NTDL multipliers will be removed from the IRCR process. Participant Peak IRCR will be calculated on a daily basis. The representative load for new meters will be calculated as the maximum of the median demand in the four peak intervals of any prior calendar month. The Coordinator's review of WEM effectiveness will include reviewing whether extreme demand	The current IRCR method does not consider demand in all system stress intervals: • in some years, the highest demand intervals are spread across six or seven days. The current IRCR method only considers four days in the Hot Season; and • in some years, the highest demand intervals are concentrated on one or two days. The current IRCR method would include only three intervals on each selected day, meaning that high demand intervals are excluded in favour of lower demand intervals. An ex-post highest demand approach was retained as it was supported by most submissions and scored highly in comparison to other options on the basis that it: • allocates costs based on contribution to the RCR; • provides a signal to amend electricity use in a way that reduces the RCR; • is simple, cost effective, and easy to understand; • aligns with the CRC methodology; • can be replicated by potential investors and other stakeholders; and • is predictable so it incentivises effective load management during system stress events All submissions except for one supported the removal of TDL/NTDL multipliers. NTDLs contribute usefully to the SWIS, but IRCR allocation is not the place to recognise this contribution. NTDLs contribute to peak demand just as TDLs do, and IRCR should be fairly allocated based on the contribution to peak demand. Submissions generally supported calculating IRCR on a daily basis with two expressing concerns about implementation costs.

Review Outcome	Rationale
events are forecast to occur outside the Hot Season.	However, AEMO confirmed that the implementation effort would be manageable.
IRCR for Flexible Capacity	
Review Outcome 2 Flexible IRCR will be based on the load shape in high ramp periods. Participants' Flexible IRCR will be calculated as follows: (1) For each Trading Interval in the previous Capacity Year, find the difference between the operational load at the end of the Trading Interval and the load at the end of the Trading Interval four hours prior. (2) Select the three Trading Days with the highest four-hour ramp value calculated under step (1). (3) For each Trading Day selected under step (2): (a) select the Trading Interval with the largest value calculated under step (1); and (b) select all Trading Intervals in the previous four hours. (4) For each participant load portfolio: (a) calculate the portfolio ramp contribution for each Trading Interval selected in step (3) as the difference between consumption at the start of that trading interval and consumption at the end of the latest selected trading interval; (b) calculate the portfolio ramp contribution for each Trading Day selected in step (2) as the maximum portfolio ramp contribution identified under step (4)(a) for Trading Intervals in that Trading Day; and (c) calculate the portfolio annual ramp contribution as the mean of the portfolio ramp contributions determined in step (4)(b).	Calculating participant IRCR using load shape in high ramp periods provides an incentive for participants to reduce their contribution to the evening ramp. This was supported by both the MAC and consultation paper submissions. The upward ramp was chosen because: • the ramp up requirement is expected to remain higher than the ramp down requirement; • facilities that can ramp up quickly can also ramp down quickly; and • ramping down in the morning period can be managed by curtailing registered solar PV facilities (those which are dispatched by the Dispatch Algorithm), while all solar facilities are naturally ramping down through the afternoon ramp and are not available to increase output in the evening. Calculating the ramp using the maximum difference between the minimum demand in the period, and the demand at the end of the period provides a balance between the ability to prevent gaming and simplicity. AEMO's provision of a forecast ramp should provide enough information for participants to make decisions to curtail their ramp to reduce their Flexible IRCR.

Review Outcome	Rationale
(5) Calculate scaling factor R as the RCR for flexible capacity divided by the sum of all portfolio annual ramp contributions. (6) For each participant load portfolio, set the flexible IRCR as the portfolio annual ramp contribution multiplied by R. AEMO will be required to publish the forecast ramp so that consumers can monitor and respond to the cost signal.	
DSP CRC	
Review Outcome 3 DSPs comprised of a single Associated Load will be allocated CRC based on the IRCR of the Associated Load less its minimum load requirement. DSPs comprised of more than one Associated Load will be allocated CRC based on their nominated response. Consumption Deviation Applications (CDAs) will be removed from the assessment of DSP CRC. AEMO will adjust consumption records when the DSP is dispatched or tested. Sites with collocated load and generation or storage are able to be Associated Loads of the DSP. Capability Class 2 facilities with collocated load and storage which hold Capacity Credits will be prohibited from self-scheduling their storage purely to reduce IRCR exposure.	The 95% POE consumption limb of the Relevant Demand calculation always sets the Relevant Demand. As a result, this method favours a flat load profile, which significantly mutes the incentive for loads with variable profiles to participate in the RCM. Participants with such flexible load can reduce their IRCR exposure by managing their own load behind the meter. Many supported the proposals, noting that self-nomination of the quantity better allowed aggregators to manage their programmes over time, and would encourage greater demand side participation in the WEM for the benefit of system security and reliability. Some submitters were concerned that proponents would nominate a higher CRC value than they were capable of providing or would make opportunistic applications not intending to follow through, and that these nominations would unreasonably reduce the capacity price for serious capacity providers. EPWA maintains that there is ample incentive to prevent this from occurring, due to the potential for DSP providers to: • lose their reserve capacity security if no capacity is made available; • pay refunds when there is a shortfall of capacity; and • pay refunds in excess of capacity payments. Submissions generally supported the proposal for the removal of CDAs. Excluding these

Review Outcome	Rationale
	maintenance intervals from consideration is inconsistent with the treatment of other facilities. Planned outages of scheduled facilities are not approved to occur at times of expected system stress, and intermittent generation is assessed on all intervals. DSP Associated Loads should also be measured on their actual consumption during periods of system stress. Almost all submissions supported the proposal, to allow sites with collocated load and generation or storage to be Associated Loads of a DSP.
DSP Dispatch	
Review Outcome 4 DSP performance will be measured against a dynamic baseline. EPWA will continue to engage with participants on the design of the dynamic baseline. AEMO will determine the DSP minimum dispatch requirement annually in the ESOO as follows: (1) identify the 50% POE peak demand; (2) identify the number of Capacity Credits held by DSPs in the latest Capacity Year for which Capacity Credits have been issued; (3) subtract the value determined in step (2) from the value determined in step (1); (4) using the load duration curve from the 10% POE peak demand forecast, identify the number of hours in which the demand is greater than the value determined in step (3); and (5) set the DSP dispatch requirement for year 3 of the current Reserve Capacity Cycle as the number of hours determined in step (4).	There was general support for the adoption of a dynamic baseline. For loads with variable consumption patterns, a static baseline can under- or overstate the counterfactual consumption during likely times of dispatch. Both under- or overstatement of the counterfactual consumption are problematic: • if the counterfactual load is overstated, then DSP dispatch will not deliver the expected reduction in load, which increases the risk to system reliability; and • if the counterfactual load is understated, then system security is not at risk, but the DSP will deliver more reduction than required or requested, meaning load will have been unnecessarily curtailed. A dynamic baseline more accurately reflects the actual curtailment delivered by the DSP compared to its level if not dispatched. A dynamic baseline also allows better forecasting of the actual response expected from dispatched DSPs, which allows more reliable operation of the power system. Under the current rules, it is more attractive for flexible loads to focus on reducing their IRCR exposure, because: • DSP CRC is set based on a 95% POE load value, while IRCR is based on the 50%

Review Outcome	Rationale
	POE load, potentially with a TDL multiplier of 1.3; and • the number of hours of reduction required to respond to IRCR signals is significantly less than the maximum potential 200 hours per year that being a DSP would require. EPWA considers that any change to the DSP minimum dispatch requirement should reflect the needs of the SWIS and that a requirement related to the expected load duration curve (LDC) is appropriate. Reducing the number of hours a DSP must be available to dispatch better aligns the availability requirement with load reductions to reduce IRCR exposure, while taking into account the number of periods a DSP is likely to be dispatched in reality. The more Capacity Credits issued to DSPs, the more hours any individual DSP would need to be dispatched to meet demand. Dispatching DSPs in only the highest demand intervals would require perfect foresight, so some adjustment factor is required. EPWA considers that it is reasonable to use the 50% POE peak demand forecast to indicate expected demand levels in which DSP dispatch is likely to occur. The number of hours in which the 10% POE peak demand exceeds the 50% POE peak demand (less the number of Capacity Credits held by DSPs) addresses this uncertainty, while ensuring that the dispatch requirement scales to reflect the size of the DSP fleet.
Reserve Capacity Testing	
Review Outcome 5 Facilities holding flexible Capacity Credits will be required to be tested for start, stop, restart, and minimum running times; ramp capability; and minimum stable loading level. The minimum requirements to be met by Flexible Capacity will be set through a process that includes consultation.	Current capacity testing focuses on the ability to deliver energy or curtail withdrawal. Flexible capacity must be able to deliver its capacity quickly and at short notice. Capacity tests for facilities holding flexible Capacity Credits need to include testing that the Facility can:

Review Outcome	Rationale
Flexible capacity may be tested through observation. When scheduling Reserve Capacity tests, AEMO will be required to consider: • whether it would make sense to schedule a Flexible Capacity test at the same time as a Peak Capacity test; and • conducting DSP tests under conditions similar to those that AEMO expects would apply when actual DSP dispatch is most likely. This will ensure that the dynamic baseline against which the tests are assessed aligns with that expected for actual DSP dispatch. A DSP failing a test will pay refunds for the reduction not achieved until it passes a subsequent test.	• reach its certified output quantity from a ‘cold’ state at its certified maximum ramp rate; and • start, stop, and restart within its certified timings. Disruption to Market Participant operations will be minimised if these aspects can be tested at the same time as peak capacity testing or by observation, when a facility demonstrates its capability outside a scheduled test. Test requirements and testing by observation were generally supported by submissions. With a dynamic baseline, testing for DSPs needs to be conducted: • against the new baseline, calculated from similar (but non-curtailed) intervals in recent historical data; and • at times which are representative of conditions under which DSPs are likely to be dispatched, so that the dynamic baseline is as close as possible to what it would be in times of system stress. DSPs that fail two tests currently have no incentive to restore their capability to meet their original level of Capacity Credits for the rest of the Capacity Year. Instead of treating a test failure as enduring unavailability of capacity, treating it in a similar manner as the start of a forced outage (meaning that the participant would incur refunds until it passed a retest) provides an incentive for participants to remedy the unavailability. There was general support to adjust the DSP testing regime in line with the dynamic baseline.
Outage Planning	
Review Outcome 6 Facilities holding Flexible Capacity Credits will be required to lodge outages if technical difficulties limit their capabilities. AEMO will be required to account for both flexible and peak capacity availability when assessing outages.	Given that the RCR for peak and flexible capacity will be different, it is likely that, at times: • sufficient peak capacity will be available so that some facilities can go on Planned Outage while leaving enough capacity to meet the expected peak demand; but

Review Outcome	Rationale
DSP owners will manage their own outages, without participating in the outage regime. DSP availability will be measured using the actual demand of the Associated Loads, rather than the Relevant Demand.	• insufficient flexible capacity will be available to ensure that the expected ramping needs can be met if flexible capacity facilities go on Planned Outage. As a result, AEMO's outage assessment process (including the opportunistic maintenance process) will need to compare the forecast need for flexible capacity with the remaining quantity of such capacity when deciding which outage requests to approve, which to reschedule, and when to reschedule them to. Flexible capacity outages were supported by almost all submissions. Some respondents raised concerns that outages affecting Flexible Capacity, while not affecting Peak Capacity, would happen so infrequently that it would not be worth the complexity involved in extending the outage regime to cover them. EPWA considers that, as Frequency Co-Optimised Essential System Services outage notification is currently separate to energy outage notification, there will not be a significant increase in complexity required to encompass Flexible Capacity. The infrequent nature of DSP dispatch and the availability incentives provided by the certification and refund processes mean that allowing participants to schedule their own outages remains appropriate. If DSP dispatch becomes more frequent, especially if DSPs move away from the top of the merit order, it may become appropriate for them to participate in the outage planning process.
Refunds	
Review Outcome 7 Capacity refunds for peak capacity and flexible capacity will be paid from separate capacity refunds pools. A dynamic refund multiplier for flexible capacity will be calculated based on a comparison of the actual ramp requirement in the interval and the	There are several reasons for separate capacity refund payment pools for peak and flexible capacity: • Peak Capacity is needed at the beginning of the Capacity Year, but Flexible Capacity is likely to be needed towards the end of the Capacity Year;

Review Outcome	Rationale
ramp rate used to set the flexible capacity RCR. The maximum capacity refund for DSPs will be increased to 125% of potential capacity payments, instead of drawing on the Reserve Capacity Security. DSPs which voluntarily surrender Capacity Credits during the Capacity Year will forfeit their DSP Reserve Capacity Security in proportion to the amount of the reduction. Capacity refunds will be distributed to Market Participants responsible for loads (and assigned IRCR), rather than other capacity providers.	• if a facility fails to meet its capacity obligations at the beginning of the capacity year and must refund all reserve capacity payments to zero, it may have no incentive to provide flexible capacity for the rest of the year; • failure to provide one product shouldn't result in the reduction of payment for the provision of another product; and • separate refund pools would prevent refunds from one capacity type from eating into refunds for the other type. This would increase the incentive to provide the other product for the rest of the capacity year. Using a ramp ratio for the dynamic refund multiplier would mean that the multiplier is consistently highest during periods of highest ramp, but more volatile. Additional incentive for DSPs is required as the capital-light nature of DSPs means that additional incentives (such as perennial DSP Reserve Capacity Security) are required. AEMO noted that drawing on Reserve Capacity Security is relatively involved and manual process, and that it is not always possible to draw on part of a security. Therefore, increasing the maximum reserve capacity refund is the best method to provide the incentive. Regarding the distribution of collected capacity refunds to participants responsible for loads, rather than other capacity providers: • Loads fund the capacity products in the first place and they, as any consumer would expect, should receive refunds in the event they do not receive all of the product they have paid for; • generators receiving capacity refunds do so without providing any additional level of service; • failure of generators to provide capacity may trigger Non-Co-Optimised Essential System Services or Supplementary Reserve Capacity, which would effectively make consumers pay twice;

Review Outcome	Rationale
	• a competitive retail market will ensure that at least some of the refunds make their way to consumers; • the capacity mechanism is designed to provide incentive for new investment without an additional revenue stream from refund rebates; and • rebating refunds to consumers aligns with the distribution of Reserve Capacity Security drawdowns.
The EUE Target in the Planning Criterion	
Review Outcome 8 The target EUE percentage in the second limb of the RCM Planning Criterion will be set to 0.0002%. The commencement date for this change will be considered further, taking into account concerns raised regarding its potential impact on AEMO's Medium Term Project Assessment of System Adequacy (MT PASA) and outage scheduling.	While the use of the 0.0002% target reduces the system stress periods included in the RLM, the analysis shows an adequate number of intervals continue to drive the CRC allocation to prevent volatility in CRC allocations between years. It is reasonable for a small, isolated power system such as the SWIS to have a higher reliability target than a large, interconnected power system such as the National Energy Market (NEM). A 0.0002% target more closely aligns the reserve margin and EUE target arms of the Planning Criterion. Following AEMO's presentation regarding outage planning at the 27 July 2023 WEM Reform Implementation Group, one stakeholder raised concerns that the change to the EUE target could affect AEMOMT PASA and outage planning, making it more difficult to schedule Planned Outages. EPWA will take this concern into account when scheduling the commencement date for this change.
Determination of the BRCP Technology	
Review Outcome 9 The WEM Rules will continue to 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.	The proposal to have the Coordinator set the BRCP reference technology was generally supported with only one submission opposing. All submissions supported separate BRCPs for different capacity types.

Review Outcome	Rationale
A separate BRCP will be calculated for each of the peak capacity and flexible capacity products. The two capacity products may have a different underlying reference technology, not just different cost components. The Coordinator will review the appropriate reference technology for each capacity product and consequently, the use of gross CONE or net CONE to set the BRCP. The Coordinator must review the reference technology and the use of a gross or net CONE approach at least every five years, and may review it more frequently if the Coordinator considers that the reference technology has changed considerably.	
RCM Expression of Interest	
Review Outcome 10 Starting from the 2024 Reserve Capacity Cycle, participants will not be required to submit an Expression of Interest (EOI) as a condition of eligibility to seek Reserve Capacity certification. Facilities for which an EOI was submitted will be allocated a Network Access Quantity (NAQ) ahead of those for which no EOI was received.	The requirement for participants to submit an EOI as a condition of being eligible to seek certification of Reserve Capacity has had several unintended results. The compulsory scheme has: • failed to produce additional certainty about what capacity will be available; • resulted in wasted effort in submitting and processing speculative and uncertain EOIs; and • potentially created a barrier for proposals that may be otherwise viable but come later in the process. Removal of the mandatory EOI requirement was raised at the 6 July 2023 RCMRWG meeting and was met with full support. Giving priority in the NAQ allocation to facilities for which an EOI has been submitted will provide participants with an incentive to use the EOI process while avoiding the issues associated with the current compulsory nature of the EOI process.

1. Introduction

Clause 2.2D.1(h) of the WEM Rules confers the function on the Coordinator of Energy (Coordinator) 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, clause 4.5.15 of the WEM Rules requires the Coordinator to review the Planning Criterion at least every 5 years.

The Coordinator, in consultation with the MAC, has reviewed the Reserve Capacity Mechanism (RCM) under clause 2.2D.1(h) of the WEM Rules. The RCM Review also incorporates the Coordinator's first review of the Planning Criterion under clause 4.5.15.

1.1 Background

1.1.1 The Performance of the RCM

The RCM has operated successfully in the WEM 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 Review

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

Since the 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 PV (DPV) has increased tenfold, and more than 1,000 MW of coal and gas capacity has or is scheduled to retire by 2030.

The SWIS is now undergoing a major transition to a lower emissions energy system because of increased penetration of DPV, the decreasing cost of renewable facilities, the Government's Renewable Energy Target, increasing pressure to reduce greenhouse gas emissions and consumers' demand for 'green' products.

At the same time, other 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 capacity sources could flatten the demand profile and delay the need for additional conventional capacity to address system stress events.

Given the changes to the nature of the demand profile and electricity supply 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 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 the 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;
- the current derating methodology for Electric Storage Resources (ESR); and
- the Energy Price Limits.[4]

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 RCM products;
    - the Benchmark Reserve Capacity Price (BRCP); and.
    - the methods for assigning Certified Reserve Capacity (CRC).[5]

4 The Coordinator recently reviewed the Energy Price Limits as part of the WEM market power mitigation strategy.

5 Alternative methods to assign CRC to intermittent generators were identified in stage one of the review and were assessed in stage two.

- Stage two assessed how the outcomes of stage one affect implementation of other parts of the RCM, including:
  - Individual Reserve Capacity Requirements (IRCR);
  - DSPs;
  - Reserve Capacity Testing;
  - outage scheduling; and
  - the refund mechanism.
- Stage three will deliver draft WEM Rules amendments.

In July 2022, the Minister for Energy directed EPWA to investigate policy options to implement penalties for high emission technologies. While not part of the original scope for the RCM Review, EPWA developed and analysed policy options in conjunction with the RCM Review. Consultation on the implementation of this policy is being conducted separately under the WEM Investment Certainty Review.[6]

The MAC has constituted the RCM Review Working Group (RCMRWG) to support the RCM Review's work. More information on the review is available from the EPWA website[7], 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.

1.2 Purpose and Structure of this Paper

This paper presents the Review Outcomes for elements of the RCM investigated in stage 2 of the RCM Review, which were subject to public consultation in May 2023. This paper is for information only, presenting the Review Outcomes for:

- IRCR for both Peak Capacity and Flexible Capacity;
- CRC allocation and dispatch for DSPs;
- the testing, outages and refunds regime;
- the unserved energy target in the Planning Criterion;
- the party responsible for setting the BRCP reference technologies; and
- the mandatory nature of the Expression of Interest (EOI) process.

Appendix A provides a summary of the feedback on the Reserve Capacity Mechanism Review Stage 2 Consultation Paper (Stage 2 Paper) and EPWA's responses to the feedback.

6 Wholesale Electricity Market Investment Certainty Review (www.wa.gov.au).

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

2. Stage 2 Review Outcomes

2.1 Individual Reserve Capacity Requirements

The IRCR calculation determines how much each participant contributes to the cost of procuring reserve capacity.

2.1.1 IRCR for Peak Capacity

IRCR is currently calculated monthly for each participant, based on consumption during either:

- twelve Trading Intervals from the previous Hot Season (December-March); or
- if the meter is new since the start of the Hot Season, four Trading Intervals from month n-3.

Temperature Dependent Loads (TDLs) and Non-Temperature Dependent Loads (NTDLs) get different treatment, with TDLs assigned a higher IRCR than an NTDL with the same metered consumption.

Only Time of Use (TOU) meters are explicitly included. All remaining meters are represented by the Notional Wholesale Meter, which is the total generation less demand measured by TOU meters. The Notional Wholesale Meter is treated as a TDL.

The Stage 2 Paper proposed to amend the IRCR methodology to:

- select intervals that better represent peak demand;
- remove TDL and NTDL multipliers; and
- calculate IRCR each day, rather than on a monthly basis.

Proposal A

> *Continue to set participant IRCR based on contribution to load in high demand intervals.*

All submissions supported continuing to set participant IRCR using contribution to load in high demand intervals.

Proposal B

> *Retain current approach of using only intervals in the Hot Season (trading days from 1 December to 31 March) to set IRCR.*
>
> *Amend the IRCR interval selection provisions to ensure that:*
>
> - *all 12 highest demand intervals in the Hot Season are selected;*
> - *intervals on a minimum of three days are selected; and*
> - *where the peak intervals occurring on each day are not contiguous, the intervening intervals are selected.*
>
> *The Coordinator's review of WEM effectiveness will include reviewing whether extreme demand events are forecast to occur outside the Hot Season.*

Most submissions supported the proposal B.

One submission preferred that AEMO designate IRCR intervals ex-ante. EPWA still considers that the proposed method is more robust and predictable, as an ex-ante method would risk the selection of periods that are not high demand periods.

One submission expressed concern that if peak periods fell in both the morning and the evening of the same day, the proposed approach would select low-demand intervals in the middle of the day. To address this concern, the methodology will exclude intervening periods if the high demand intervals are separated by significantly lower demand intervals on the same day.

Proposal C

> *Remove TDL/NTDL multipliers from the IRCR process.*

All submissions except for one supported the removal of TDL/NTDL multipliers. The single dissenting submission argued that NTDLs provide benefit to the SWIS by:

- reducing uncertainty around peak demand; and
- consuming during low load periods in the middle of the day.

EPWA agrees that NTDLs contribute usefully to the SWIS, but considers that the IRCR allocation is not the place to recognise this contribution. NTDLs contribute to peak demand just as TDLs do, and IRCR will be allocated more effectively based on their contribution to peak demand.

Proposal D

> *Calculate IRCR on a daily basis.*
>
> *Set representative load for new meters based on the maximum of the median demand in the four peak intervals of any prior calendar month.*

Submissions generally supported the change.

Two submissions expressed concern about potential implementation costs. EPWA understands that the main consideration for implementation costs is the volume of data required. Given that an amended IRCR method is being implemented, AEMO would need to automate the calculation. Changing the calculation frequency will require a small (though not trivial) implementation effort.

Review Outcome 1

IRCR requirements will continue to apply to a participant's contribution to load in high demand intervals during the Hot Season.

Peak IRCR intervals will be selected as follows:

(1) identify the 12 intervals from the previous Hot Season (December-March) with the highest total sent out generation (SOG);

(2) identify the trading days on which those intervals fell;

(3) if fewer than three days are identified in step (2), identify the additional days in the Hot Season with the highest SOG outside the top 12 intervals to make a total of three days, rather than one or two days;

(4) for each identified day, select:

  (a) the interval with the highest SOG;

(b) all other intervals that are in the top 12 intervals;

(c) if the intervals selected in steps (4)(a) and (4)(b) are less than three hours apart, all intervals between the intervals selected in steps (4)(a) and (4)(b); and

(d) If fewer than three intervals have been selected, select the next highest SOG intervals on either side of the selected intervals to make up to three intervals.

TDL/NTDL multipliers will be removed from the IRCR process.

Participant Peak IRCR will be calculated on a daily basis.

The representative load for new meters will be calculated as the maximum of the median demand in the four peak intervals of any prior calendar month.

The Coordinator's review of WEM effectiveness will include reviewing whether extreme demand events are forecast to occur outside the Hot Season.

2.1.2 IRCR for Flexible Capacity

Proposal E

Set participant IRCR for flexible capacity based on the load shape in high ramp periods.

Submissions generally supported the proposal.

One submitter noted that, while loads are currently the dominant causer of the ramping requirement, changes in the output of utility scale intermittent generation may make up the dominant part of the ramping requirements in the future and, if that occurs, it would make sense to revisit the flex IRCR allocation method.

Proposal F

Set IRCR for flexible capacity based on the three days with the highest four-hour upwards ramp at any time during the year.

Require AEMO to publish the forecast ramp so that consumers can monitor and respond to the cost signal.

Submissions generally supported the proposal.

Two submissions preferred that Flexible IRCR periods be set ex-ante, as doing so would avoid the need for participants to proactively reduce consumption in intervals which might turn out not to be IRCR intervals.

As noted in section 2.1.1, EPWA does not favor the ex-ante method due to the risk of mis-forecasting system stress periods for the system as a whole. AEMO's provision of a forecast ramp should provide enough information for participants to make decisions to reduce their contribution to the ramp in order to reduce their Flexible IRCR.

One submission supported the proposal, as long as there is a way for DSPs to be certified for Flexible Capacity. EPWA agrees that if a DSP can respond flexibly and at short notice, then it should be eligible to receive Flexible CRC.

One submission observed the potential for participants to game the Flexible IRCR allocation process by briefly increasing their load at the start of the Flexible IRCR assessment period (for example by turning off their BTM solar), they may be able to avoid flex IRCR allocation entirely. EPWA has amended the calculation process to address this risk.

Under the amended calculation, a participant could still reduce its Flexible IRCR by correctly predicting the last interval of the ramp period and reducing its demand in that interval, but this would help reduce the ramp requirement and potentially change when the highest four-hour ramp occurs.

Review Outcome 2

Flexible IRCR will be based on the load shape in high ramp periods.

Participants' Flexible IRCR will be calculated as follows:

(1) For each Trading Interval in the previous Capacity Year, find the difference between the operational load at the end of the Trading Interval and the load at the end of the Trading Interval four hours prior.

(2) Select the three Trading Days with the highest four-hour ramp value calculated under step (1).

(3) For each Trading Day selected under step (2):

   (a) select the Trading Interval with the largest value calculated under step (1); and

   (b) select all Trading Intervals in the previous four hours.

(4) For each participant load portfolio:

   (a) calculate the portfolio ramp contribution for each Trading Interval selected in step (3) as the difference between consumption at the start of that trading interval and consumption at the end of the latest selected trading interval;

   (b) Calculate the portfolio ramp contribution for each Trading Day selected in step (2) as the maximum portfolio ramp contribution identified under step (4)(a) for Trading Intervals in that Trading Day; and

   (c) calculate the portfolio annual ramp contribution as the mean of the portfolio ramp contributions determined in step (4)(b).

(5) Calculate scaling factor R as the RCR[8] for flexible capacity divided by the sum of all portfolio annual ramp contributions.

(6) For each participant load portfolio, set the flexible IRCR as the portfolio annual ramp contribution multiplied by the scaling factor.

AEMO will be required to publish the forecast ramp so that consumers can monitor and respond to the cost signal.

[8] This step could also use the total Flexible Capacity Credits issued. EPWA will consider this simplification during rule drafting.

2.2 Demand Side Programmes

2.2.1 DSP CRC

Currently each DSP is allocated CRC based on its Relevant Demand, which is the lower of:

- the aggregate IRCRs of its Associated Loads; and
- its historical 95% POE consumption during the 200 intervals with the highest generation.

Participants can request to exclude intervals from the calculation where the load was out for maintenance by submitting a Consumption Deviation Application (CDA).

The 95% POE consumption limb of the Relevant Demand calculation always sets the Relevant Demand. As a result, this method favours a flat load profile, which significantly mutes the incentive for loads with variable profiles to participate in the RCM. Participants with such flexible load can reduce their IRCR exposure by managing their own load behind the meter.

EPWA proposed to amend the DSP certification process so that there are two certification approaches, depending on whether a DSP keeps the same Associated Loads from year-to-year.

Proposal G

> *Where a DSP has:*
>
> - *the same Associated Loads that it had in the previous year, assign CRC based on IRCR of the Associated Loads less the minimum load requirement of the Associated Loads; and*
> - *different Associated Loads from the previous year, assign CRC based on a value nominated by the Market Participant.*

Submissions expressed mixed views.

Many supported the proposals, noting that self-nomination of the quantity would allow aggregators to better manage their programmes over time and would encourage greater demand side participation in the WEM.

Some submitters were concerned that proponents would nominate a higher CRC value than they were capable of providing or would make opportunistic applications not intending to follow through, and that these nominations would unreasonably reduce the capacity price for serious capacity providers.

EPWA considers that ample incentives will be put in place to prevent this from occurring, due to the potential for DSP providers:

- losing reserve capacity security if no capacity is made available;
- paying refunds when there is a shortfall of capacity; and
- paying refunds in excess of capacity payments (as a result of Review Outcome 7).

Other participants were concerned about the implementation complexity of having two assessment regimes. One participant noted the potential complexity in assessing which approach a given aggregation would be subject to.

EPWA acknowledges these submissions and has simplified the proposal to reduce complexity and increase clarity.

Proposal H

> *Remove CDAs from the assessment of DSP CRC.*

Submissions generally supported the proposal.

One submission requested clarification on when records would need to be adjusted. EPWA confirms that consumption records adjustment would only be performed when a DSP is dispatched or tested.

One submission was concerned about the treatment of DSP CRC in the event consumption of an Associated Load is constrained by a Dynamic Operating Envelope (DOE). EPWA considers that DSPs should account for the potential effects of DOEs when nominating their CRC value and notes that Western Power will need to be clear on any restrictions it places on connections to its network.

Proposal I

> *Allow sites with collocated load and generation or storage to be Associated Loads of a DSP.*

Almost all submissions supported the proposal and none opposed it.

AEMO sought clarification whether the proposal:

- relates only to Non-Scheduled Facilities; and
- is seeking to remove the concept of Separately Certified Components from the WEM Rules.

AEMO noted that Separately Certified Components are used throughout AEMO's processes and systems, and that removing this concept from the WEM Rules would require significant implementation effort across most aspects of AEMO's operations.

EPWA confirms that the proposal currently relates only to Associated Loads with generation or storage that does not exceed the mandatory registration threshold.

One of the RCM Review Outcomes is to remove the requirement to register separate components of a facility, so that the facility as a whole can be assigned a single Capability Class, but acknowledges that this may require significant implementation effort and will continue to engage with AEMO to consider how this can be done while reducing that effort.

EPWA also notes that developing the relevant draft rules and implementing this proposal will take considerable amount of time and will take this into account in its planning activities in consultation with AEMO.

Review Outcome 3

DSPs comprised of a single Associated Load will be allocated CRC based on the IRCR of the Associated Load less its minimum load requirement.

DSPs comprised of more than one Associated Load will be allocated CRC based on their nominated response.

CDAs will be removed from the assessment of DSP CRC. AEMO will adjust consumption records when the DSP is dispatched or tested.

Sites with collocated load and generation or storage are able to be Associated Loads of the DSP. Capability Class 2 facilities with collocated load and storage which hold Capacity Credits will be prohibited from self-scheduling their storage purely to reduce IRCR exposure.

2.2.2 DSP Dispatch

DSPs are scheduled and dispatched differently from generation facilities. Their nature as a last-resort reserve capacity supplier means that they are very seldom dispatched, and their provision of load reduction means that their contribution must be measured against a counterfactual of what they would have consumed if they had not been dispatched.

DSPs can currently be dispatched for up to 200 hours each year.

Under current arrangements, DSPs are dispatched against a static baseline – the Relevant Demand.

Proposal J

Adopt a dynamic baseline to measure DSP dispatch performance against.

Continue to assess the detailed dynamic baseline methodology.

Consider reducing the number of hours that DSPs can be dispatched.

There was general support for adopting a dynamic baseline, with one submission noting that a dynamic baseline would need to be flexible enough to account for a participant responding to IRCR signals during the Hot Season and either responding or not responding on the same day as being dispatched. EPWA notes that, if a participant chooses to reduce consumption to reduce its IRCR exposure during a baseline period, its baseline for DSP dispatch would also be reduced from what it would have been had the participant not sought to manage its IRCR.

Several submissions supported reducing the total number of hours for which a DSP can be dispatched, stating that this is a major barrier to more DSPs entering the market. Submitters proposed various changes to DSP requirements:

- one submitter considered that the current dispatch notice period (two hours) is too short and creates a barrier to many providers;
- one submitter proposed that the duration requirement could be reduced to from 200 to 20 hours;
- one submitter suggested reducing the requirement for DSPs to be available for at least 12 hour on each day to 4 hours; and
- one submitter proposed that DSP availability hours be based on the historical dispatch of DSPs, plus a margin to reflect uncertainty.

Three submissions considered that DSP capacity compensation should be reduced in line with any availability requirements reduction.

During RCMRWG discussions, participants noted that flexible loads have a choice between using their flexibility to:

- reduce consumption during likely IRCR periods, therefore reducing their IRCR exposure; and
- participate in the WEM as a DSP, receive capacity payments, and potentially be dispatched at a time selected by AEMO.

Under the current rules, it is more attractive for flexible loads to focus on reducing their IRCR exposure, because:

- DSP CRC is set based on a 95% POE load value, while IRCR is based on the 50% POE load, potentially with a TDL multiplier of 1.3.

  This issue is already being addressed by the changes to DSP participation as a result of other RCM Review outcomes.
- The number of hours of reduction required to respond to IRCR signals is significantly less than the maximum potential 200 hours per year that being a DSP would require.

EPWA considers that any change to the DSP minimum dispatch requirement should reflect the needs of the SWIS and result in overall benefit to the WEM, and that a requirement consistent with the expected load duration curve (LDC) would be appropriate.

An LDC based approach to DSP dispatch requirements

Currently, DSPs hold 86 MW of capacity credits. If those facilities were dispatched at maximum for the entire year, peak demand would be reduced by 86MW.

The 2022 ESOO forecast a 10% POE peak demand of 4,055 MW for the 2023 Capacity Year, meaning that 3,969 MW of non-DSP capacity is required (excluding capacity required to meet the highest contingency and ESS requirements). If DSPs are only ever dispatched as a last resort, at the top of the merit order stack, then they would only be dispatched when the demand is above 3,969 MW.

The more Capacity Credits are issued to DSPs, the more hours any individual DSP would need to be dispatched to meet demand.

Dispatching DSPs in only the highest demand intervals would require perfect foresight, so some adjustment factor is required. EPWA considers that it is reasonable to use the 50% POE and 90% POE peak demand forecasts to indicate expected demand levels at which DSP dispatch is likely to occur. The number of hours in which the 10% POE peak demand exceeds the 50% POE and 90% POE peak demands would allow for this uncertainty.

Using hourly demand forecast data for each capacity year from 2016 to 2020, scaled so that the peak demand matches the expected 10% POE peak demand for the 2023 capacity year, Table 1 shows the number of hours in which the 2023 Capacity Year 10% POE peak demand exceeds:

- the 50% POE (less the number of Capacity Credits currently held by DSPs); and
- the 90% POE (less the number of Capacity Credits currently held by DSPs).

Table 1: Number of hours above demand threshold

Capacity Year LDC	Hours above CY23 10% POE peak less DSP CCs (3,969 MW)	Hours above CY23 50% POE peak less DSP CCs (3,704 MW)	Hours above CY23 90% POE peak less DSP CCs (3,645 MW)
2016	2	20	76
2017	2	5	21
2018	1	27	91
2019	2	4	32
2020	1	9	48
Mean	1.6	13.0	53.6
Mean less 2018	1.8	9.5	44.3
Maximum	2	27	91
Maximum less 2018	2	20	76

2018 had a relatively low peak demand, meaning that its LDC is considerably flatter than the other years in the sample. It is removed for the purposes of the Relevant Level Method developed under Stage 1 of the RCM Review, so it would be reasonable to remove it here as it does not represent the expected LDC shape in a 10% POE peak year.

Based on this data, if DSPs were dispatched whenever demand exceeded the 90% POE peak less the number of DSP Capacity Credits issued, they could expect to be dispatched for around 45 hours in 9 years out of 10, or a total of around 400 hours over ten years.[9]

If DSPs were dispatched when demand exceeded the 50% POE peak less the number of DSP Capacity Credits issued, they could expect to be dispatched for around 10 hours in 5 years out of ten, or a total of around 50 hours over ten years. Depending on the shape of the year's LDC, DSPs could be dispatched for up to 20 hours in a single year (if the load was shaped like in 2016) or as few as four hours (if the load was shaped like in 2019).

This method will result in a higher number of dispatch hours when more Capacity Credits are on issue to DSPs. For example, this method would result in between 8 and 40 hours in a single year if DSPs are issued 200 MW of Capacity Credits and between 17 and 70 hours in a single year if DSPs are issued 300 MW of Capacity Credits.

Anecdotally, flexible loads that focus on IRCR reduction proactively respond in around 8 to 12 days per year, each with 2 to 4 hours of response, or a total of around 300 hours of response over 10 years, with a maximum of around 50 hours of response in a single year.

9 This assumption does not account for outages, NCESS and excess capacity.

Regarding the suggestion to reduce the 12 hour availability requirement for DSPs to 4 hours, EPWA considers that DSP providers can aggregate Associated Loads so each Load within an aggregation has to be available for only 4 hours. Therefore, EPWA considers that reducing the 12 hours availability requirement for DSPs is unnecessary, as any such reduction may undermine the reliability objectives of the RCM.

Review Outcome 4

DSP performance will be measured against a dynamic baseline. EPWA will continue to engage with participants on the design of the dynamic baseline.

AEMO will determine the DSP minimum dispatch requirement annually in the ESOO as follows:

(1) identify the 50% POE peak demand;

(2) identify the number of Capacity Credits held by DSPs in the latest Capacity Year for which Capacity Credits have been issued;

(3) subtract the value determined in step (2) from the value determined in step (1);

(4) using the load duration curve from the 10% POE peak demand forecast, identify the number of hours in which the demand is greater than the value determined in step (3); and

(5) set the DSP dispatch requirement for year 3 of the current Reserve Capacity Cycle as the number of hours determined in step (4).

2.3 Testing, Outages and Refunds

2.3.1 Reserve Capacity Testing

The Reserve Capacity testing regime ensures that facilities holding Capacity Credits can effectively deliver the capacity that they are paid to provide.

The current capacity testing regime tests the ability of a facility to reach its maximum certified output level twice per year – once between October and March, and again between April and September.

A facility can pass during a scheduled test or by observation, if it happens to achieve its required level in the normal course of market operations. A facility gets two chances to pass a scheduled test – if it fails both, its Capacity Credits are reduced to the maximum level achieved.

DSPs are treated differently – they undergo two tests:

- one between October and March, for the full quantity of Capacity Credits held. A DSP gets two chances to pass this test – if it fails twice, Capacity Credits are reduced to the level of reduction achieved, and it must refund any capacity payments relating to the non-performing capacity; and
- one in October/November, for 10% of assigned Capacity Credits. A DSPs Capacity Credits will be reduced to zero upon failing the test, until the test is repeated, and will be reduced to zero for the year if the test is failed twice.

Proposal K

Require facilities holding Flexible Capacity Credits to be tested for start, stop, restart, and minimum running times; ramp capability; and minimum stable loading level.

Allow facilities to pass flexible capacity tests by observation.

Require AEMO to schedule tests of flexible capacity characteristics to coincide with tests for peak capacity.

This proposal was generally supported, with several submissions providing feedback on the details of the testing regime. Recommendations included that:

- testing for DSPs holding Flexible Capacity Credits should be approached in the same way as testing Peak Capacity;
- submission of Fast Start Inflexibility Profiles should be mandatory for facilities holding Flexible Capacity Credits;
- dual-fuelled facilities should be allowed to demonstrate their compliance with Flexible Capacity obligations using the fuel that reflects their expected flexible operating pattern; and
- the minimum requirements for flexible plants should be established through a consultative process.

Testing flexibility by observation was universally supported.

One submission considered that Flexible Capacity tests need not be conducted at the same time as Peak Capacity tests because the two functions are different.

EPWA is open to these implementation-focused recommendations and will consult further on implementation detail through the rule drafting process.

Proposal L

Adjust Reserve Capacity Testing for DSPs to reflect a shift to a dynamic dispatch baseline.

Require AEMO to consider the expected baseline when scheduling DSP tests.

Treat a failed test as the beginning of a forced outage, rather than a permanent reduction of Capacity Credits.

Support for this proposal was mixed. There was general support to adjust the testing regime in line with the dynamic baseline, although one respondent submitted that DSPs should be tested based on output abilities at ambient temperature just like other capacity types. EPWA maintains that generation and demand side capacity functions differently and that DSP testing should reflect their different characteristics.

One submission proposed reducing the number of tests to one per year, as this would reduce unnecessary costs to participants. EPWA considers that the two tests already provide a suitable balance between confidence in performance and costs to participants.

One submission considered that the treatment of a failed test as the beginning of a forced outage could unfairly penalize resources that cannot remedy their unavailability. EPWA believes that this treatment of unavailability is fair and provides a suitable balance between penalties and incentive to provide the service for the rest of the capacity year.

Review Outcome 5

Facilities holding flexible Capacity Credits will be required to be tested for start, stop, restart, and minimum running times; ramp capability; and minimum stable loading level. The minimum requirements to be met by Flexible Capacity will be set through a process that includes consultation.

Flexible capacity may be tested through observation.

When scheduling Reserve Capacity tests, AEMO will be required to consider:

- whether it would make sense to schedule a Flexible Capacity test at the same time as a Peak Capacity test; and
- conducting DSP tests under conditions similar to those that AEMO expects would apply when actual DSP dispatch is most likely. This will ensure that the dynamic baseline against which the tests are assessed aligns with that expected for actual DSP dispatch.

A DSP failing a test will pay refunds for the reduction not achieved until it passes a subsequent test.

2.3.2 Outage Planning

Proposal M

> *Amend the outage planning process so that AEMO considers availability of both peak and flexible capacity when assessing and approving outages.*

This proposal was supported by almost all submissions.

One submitter considered it unnecessary to codify the consideration of flex capacity into outage scheduling as AEMO was already able to use its discretion when planning outages. EPWA maintains that explicitly accounting for flexibility in the outage planning process is important for system security. Therefore, AEMO should be required to account for both flexible and peak capacity availability when assessing outages.

Proposal N

> *Require flexible capacity holders to lodge outages relating to capability to provide flexible capacity.*

Support for this proposal was mixed. Respondents understood the rationale, but raised concerns that outages affecting Flexible Capacity while not affecting Peak Capacity would happen so infrequently that it would not be worth the complexity involved in extending the outage regime to cover them.

It is difficult to identify how often such an outage might occur. However, the current outage regime already requires participants to notify outages of Frequency Co-Optimised Essential System Services (FCESS) capability separately from energy capability, so there will not be a significant increase in complexity required to encompass Flexible Capacity.

Proposal O

> *Allow DSP owners to manage their own outage schedules, without participating in the outage planning regime.*

Adjust DSP availability measurement to use actual demand of the Associated Loads rather than the Relevant Demand.

This proposal was supported by almost all submissions.

One submitter expressed concern that DSP outages may affect reserve margins that influence whether generator outages are approved.

EPWA considers that, because the effect of self-scheduled DSP outages will be reflected in their baselines, there is sufficient incentive to schedule DSP outages in non-peak periods.

Review Outcome 6

Facilities holding Flexible Capacity Credits will be required to lodge outages where technical difficulties limit their capabilities.

AEMO will be required to account for both flexible and peak capacity availability when assessing outages.

DSP owners will manage their own outages, without participating in the outage regime.

DSP availability will be measured using the actual demand of the Associated Loads, rather than the Relevant Demand.

2.3.3 Refunds

Proposal P

Capacity refunds for both peak capacity and flexible capacity will be paid from a single pool of capacity payments.

Capacity refunds for flexible capacity will be capped at a set portion of total capacity revenues.

Support for this proposal was mixed. Issues raised included that:

- Peak Capacity is needed at the beginning of the Capacity Year, but Flexible Capacity is likely to be needed towards the end of the Capacity Year;
- if a facility fails to meet its capacity obligations at the beginning of the capacity year and must refund all reserve capacity payments to zero, it may have no incentive to provide capacity for the rest of the year;
- failure to provide one product shouldn't result in the reduction of payment for the provision of another product; and
- separate refund pools would prevent refunds from one capacity type from eating into refunds for the other type. This would increase the incentive to provide the other product for the rest of the capacity year.

EPWA agrees that these points are compelling, particularly the final point, and that it is necessary to have separate refund pools for Peak Capacity and Flexible Capacity.

Proposal Q

Calculate a dynamic refund multiplier for flexible capacity based on a comparison of the actual ramp requirement in the interval and the ramp rate used to set the flexible capacity RCR.

Apply the greater of the peak and flexible multipliers to refunds for facilities supplying both capacity products.

Support for the proposal was mixed.

Participants did not comment on the use of a dynamic refund multiplier for flexible capacity based on a comparison of the actual ramp requirement in the interval and the ramp rate.

One submission questioned the need for separate multipliers while others noted issues with the use of a single pool.

Proposal R

Amend the Maximum Facility Refund for DSPs to include the DSM Reserve Capacity Security.

DSPs which voluntarily surrender Capacity Credits during the Capacity Year will forfeit their DSM Reserve Capacity Security in proportion to the amount of the reduction.

Support for the proposal was mixed.

One respondent submitted that the current DSP refund regime is sufficient to ensure capacity availability. EPWA maintains that the capital light nature of DSPs means that additional incentives (such as perennial DSP Reserve Capacity Security) are required.

AEMO noted that drawing on Reserve Capacity Security is relatively involved and manual process, and that it is not always possible to draw on part of a security. This means that the Consultation Paper proposal would be difficult to implement.

EPWA considered two other options for DSP refunds:

- An increased refund cap, whereby the DSP maximum capacity refund could be more than the total capacity payments for the year, but without drawing on the Reserve Capacity Security.
- Excluding test failure refunds from the refund cap. If a DSP fails a Reserve Capacity test, it would start paying refunds until it passes a test, and those refunds would be excluded from the refund cap.

Under either approach DSPs would need to post prudential security, and some additional cap would be required to avoid the potential for unlimited refunds. While such a cap could be seen as arbitrary, EPWA considers that it would be reasonable to apply a cap of 125% of the total capacity payments, as this would match the reserve capacity security at risk without the potential difficulties associated with drawing on part of the security.

Proposal S

Distribute collected capacity refunds to participants, responsible for loads, rather than other capacity providers.

Currently, collected capacity refunds are distributed to other capacity providers who met their obligations during the relevant periods. This increases the incentive for capacity providers to be available during periods of high refund rates, by rewarding those who remain available when others are not. The net amount of capacity payments remains the same, and the amount paid by consumers does not change.

At market start, refunds were distributed to consumers, but this was changed to generators on 1 October 2017 with the commencement of *Wholesale Electricity Market Rules Amending Rules 2016, Schedule B, Part 3*. EPWA considers that the rationale for this change is no longer applicable. A paper discussing the proposed change in allocation of Capacity Rebates from consumers to generators[10] noted that:

> Retailers who benefit from a capacity payment refund will in most cases not experience a power supply disruption – as other capacity providers deliver aggregate capacity to meet demand. This means that the retailer still receives the service it has paid for in its Capacity Credit obligation, but also receives a refund on that cost for no diminution in that level of service.

While the WEM had an oversupply of capacity in the mid-2010s, it was reasonable to assume that, in most cases, outages resulting in capacity refunds were unlikely to also result in reliability concerns. However, the WEM is now projected to have a shortfall of capacity, resulting in the procurement of both Supplementary Reserve Capacity (SRC) and Non-Co-Optimised Essential System Services (NCESS) to provide additional peak capacity. These shortfalls are being driven[11] in significant part by lower than expected plant availability, as well as fuel supply uncertainty which has, in the recent past, led to prolonged forced outages.

If refunds continue to be distributed to generators, consumers (who pay for both SRC and NCESS) will pay more to receive the same level of reliability, while generators who are simply providing the service they have already been paid for also receive an additional revenue stream for no increase in the level of service provided.

EPWA therefore proposed to distribute capacity refunds to participants responsible for loads rather than to other capacity providers.

Submissions for this proposal were polarised with strong support from customers and strong opposition from generators.

Generators provided rationale for retaining the current approach, including:

- a lack of deliberation in the review process compared to when the rule was changed in 2017;
- that retailers would not necessarily pass on refunds to customers;
- that rebating refunds to consumers would reduce the incentive for new generation to enter the market; and
- that installed capacity shortfalls will likely be the main driver of NCESS and SRC procurement, not reduced generator availability.

AEMO submitted that unavailability of capacity for a long duration could become a NCESS/SRC trigger.

10 https://www.wa.gov.au/system/files/2019-08/Position-Paper-on-Reforms-to-the-Reserve-Capacity-Mechanism.pdf

11 https://www.wa.gov.au/system/files/2022-12/221214-NCESS%20Trigger%20Submission-Reliability-Resubmission-Redacted.pdf

An additional meeting of the RCMRWG was held on 13 July 2023 to discuss solely this matter. The views during the meeting were finely balanced between support for and opposition to the proposal, with most of the considerations raised reflecting previous discussions and matters raised in submissions. The following new considerations were provided:

- generators considered that recycling the refunds to capacity providers rewards facilities that are available and, therefore, increases the incentive for other capacity providers to be available to avoid providing financial benefit to their competitors;
- retailers and customers considered that Forced Outages lead to increased energy prices (Short Term Energy Market, Balancing Market and FCESS prices) resulting in higher costs to customers and higher profits for generators that are available for dispatch;
- generators argued that most Market Participants are not affected by the energy prices as they have bilateral contracts;
- retailers and customers considered that, in practice, it did not matter whether participants were bilaterally contracted as bilateral contracts are hedging tools protecting both parties from extreme prices; and
- retailers and customers argued that retailers will pass through at least part of the refunds to consumers, while consumers will not benefit from the refunds if they are recycled to generators.

At the 20 July 2023 MAC meeting, members echoed the RCMRWG views. One member proposed that refunds could be used to cover the cost of SRC with the residual continuing to be rebated to generators, and that any change should be held off, so as not to exacerbate revenue adequacy issues until they had been addressed through the WEM Investment Certainty Review.

Another MAC member noted that the WEM Investment Certainty Review is investigating solutions to potential medium-term revenue shortfalls for new renewable generators, and that there is no evidence to suggest that there is a revenue adequacy issue for existing generators. EPWA agrees with this view.

Taking all of the views into account, while EPWA acknowledges that rebating the refunds to other capacity providers may increase incentives for participants to ensure their capacity is available, it considers that distributing capacity refunds to loads is the preferred option because:

- loads pay for the capacity products and they, as any consumer would expect, should receive refunds in the event they do not receive all of the product they have paid for;
- generators receiving capacity refunds do so without providing any additional level of service;
- risks associated with generator availability have resulted in triggering NCESS or SRC, which would effectively make consumers pay twice;
- while the competitive retail market in Western Australia will ensure that at least some of the refunds make their way to consumers in the long run, the recent capacity availability issues have led to additional costs to retailers and their customers in the short term;
- the capacity mechanism was designed to provide sufficient incentive for new investment without an additional revenue stream from refund rebates;

- the refund mechanism is designed to provide strong incentive for capacity to be available, and the current rebate mechanism may reduce this incentive[12];
- high levels of forced outages result in significant increases to the STEM and balancing prices for the remaining available generators;
- generators being bilaterally contracted is not a reason for them to receive additional payments through the refunds as bilateral contracts also protect them from low prices; and
- rebating refunds to consumers aligns with the distribution of Reserve Capacity Security drawdowns.

Review Outcome 7

Capacity refunds for peak capacity and flexible capacity will be paid from separate capacity refunds pools.

A dynamic refund multiplier for flexible capacity will be calculated based on a comparison of the actual ramp requirement in the interval and the ramp rate used to set the flexible capacity RCR.

The maximum capacity refund for DSPs will be increased to 125% of potential capacity payments, instead of drawing on the Reserve Capacity Security.

DSPs which voluntarily surrender Capacity Credits during the Capacity Year will forfeit their DSP Reserve Capacity Security in proportion to the amount of the reduction.

Capacity refunds will be distributed to Market Participants responsible for loads (and assigned IRCR), rather than other capacity providers.

2.4 Other Matters

2.4.1 The EUE Target in the Planning Criterion

Proposal T

Amend the target EUE percentage in the second limb of the RCM Planning Criterion to 0.0002% of annual energy consumption.

Submissions were mixed on this proposal. Concerns raised were that:

- reducing the EUE target reduces the number of peak periods affecting the fleet ELCC, potentially increasing the volatility of CRC allocations to intermittent generators; and
- the 0.0002% target is three times more stringent than the target in the National Energy Market (NEM).

EPWA maintains that a 0.0002% target is appropriate:

12 Under the current mechanism, generators paying refunds for some intervals (some of their capacity) still receive rebates for other intervals (the rest of their capacity).

- while the use of the 0.0002% target reduces the system stress periods included in the RLM, analysis shows that an adequate number of intervals continue to drive the CRC allocation to prevent volatility in CRC allocations between years;
- it is reasonable for a small, isolated power system such as the SWIS to have a higher reliability target than a large, interconnected power system such as the NEM; and
- a 0.0002% target more closely aligns the reserve margin and EUE target arms of the planning criterion.

Following AEMO's presentation regarding outage planning at the 27 July 2023 WEM Reform Implementation Group, one stakeholder raised concerns that the change to the EUE target could affect AEMO's Medium Term Project Assessment of System Adequacy (MT PASA) and outage planning, making it more difficult to schedule Planned Outages. EPWA will take this concern into account when scheduling the commencement date for this change.

Review Outcome 8

The target EUE percentage in the second limb of the RCM Planning Criterion will be set to 0.0002%. The commencement date for this change will be considered further, taking into account concerns raised regarding its potential impact on the MT PASA and outage scheduling.

2.4.2 Determination of the BRCP Technology

Proposal U

> *The WEM Rules will continue to 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 separate BRCP will be calculated for each of the peak capacity and flexible capacity products. The two capacity products may have a different underlying reference technology, not just different cost components.*
>
> *The Coordinator will review the appropriate reference technology for each capacity product and, consequently, the use of gross CONE or net CONE to set the BRCP, in 2024.*
>
> *The Coordinator must review the reference technology and the use of a gross or net CONE approach at least every five years, and may review it more frequently if the Coordinator considers that it has changed considerably.*

The proposal to have the Coordinator set the BRCP reference technology was generally supported with only one submission opposing. All submissions supported separate BRCPs for different capacity types.

Submitters reiterated concerns about the use of net CONE, noting:

- the difficulty of accurate calculations; and
- the detrimental effects for the capacity mechanism if the BRCP is too low to encourage investment.

Review Outcome 9

The WEM Rules will continue to 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 separate BRCP will be calculated for each of the peak capacity and flexible capacity products. The two capacity products may have a different underlying reference technology, not just different cost components.

The Coordinator will review the appropriate reference technology for each capacity product and consequently, the use of gross CONE or net CONE to set the BRCP.

The Coordinator must review the reference technology and the use of a gross or net CONE approach at least every five years, and may review it more frequently if the Coordinator considers that the reference technology has changed considerably.

2.4.3 Removal of Mandatory Expressions of Interest

In June 2021, the Tranche 3 Amending Rules introduced a new clause 4.2.1 requiring participants to submit an EOI as a condition of being eligible to seek certification of Reserve Capacity. This requirement applied for the 2022 and 2023 reserve capacity cycles, for CRC assigned for the 2024 and 2025 Capacity Years.

The requirement resulted in a significant increase in EOIs from prospective capacity providers, many of which were speculative or included multiple potential configurations for a single facility. Table 2 below shows the sharp uptick in EOIs starting from 2022.

Table 2: Expression of Interest statistics

Year	2010	2011	2012	2013	2014	2015/16	2017	2018	2019	2020	2021	2022	2023
EOIs	16	8	17	9	5	1	3	1	2	3	29	164	137
Unique valid EOIs	16	8	17	9	5	1	3	1	2	3	25	91	72
DSP MW	228	101	19	2	0.25	0	0	0	0	0	5	0	0
Total MW	644	337	214	59	56	42	323	10	32	62	301	1311	1077

EPWA considers that the requirement has:

- failed to produce additional certainty about what capacity will be available;
- resulted in wasted effort in submitting and processing speculative and uncertain EOIs; and
- potentially, created a barrier for proposals that may be otherwise viable but come late in the process.

Removal of the mandatory EOI requirement was raised at the RCMRWG meeting on 6 July 2023 and was met with full support.

Before the 2021 amendments, facilities which submitted EOI were allocated NAQ ahead of other facilities, providing participants with an incentive to use the EOI process while avoiding some of the issues resulting from the compulsory EOI process.

Review Outcome 10

Starting from the 2024 Reserve Capacity Cycle, participants will not be required to submit an EOI as a condition of eligibility to seek Reserve Capacity certification.

Facilities for which an EOI was submitted will be allocated NAQ ahead of those for which no EOI was received.

Appendix A. Responses to the Stage 2 Consultation Paper

<table>
<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA’s Response</th></tr>
<tr><td colspan="3">Proposal A:
Continue to set participant IRCR based on contribution to load in high demand intervals.</td></tr>
<tr><td colspan="3">The following stakeholders indicated that they ‘support’ or generally support the proposal:
Alinta Energy
Change Energy
Expert Consumer Panel
Enel X
Karara Mining Limited
Perth Energy
Synergy</td></tr>
<tr><td colspan="3">Proposal B:
Retain the current approach of using only intervals in the Hot Season (trading days from 1 December to 31 March) to set IRCR.
Amend the IRCR interval selection provisions to ensure that:
all 12 highest demand intervals in the Hot Season are selected;
intervals on a minimum of three days are selected; and
where the peak intervals occurring on each day are not contiguous, the intervening intervals are selected.
The Coordinator’s review of WEM effectiveness will include reviewing whether extreme demand events are forecast to occur outside the Hot Season.</td></tr>
<tr><td colspan="3">The following stakeholders indicated that they ‘support’ or generally support the proposal:
Alinta Energy
Change Energy
Collgar
Expert Consumer Panel
Perth Energy
Synergy
Change Energy</td></tr>
<tr><td>Australian Energy Council (AEC)</td><td>AEC seeks further information about how the methodology would be applied if there were a large gap between peak intervals on a day (for example, there could be a peak in the morning and evening) and whether there would be limits on intervening intervals.</td><td>To avoid selecting low-demand intervals in the middle of the day, the methodology will be implemented to exclude intervening periods in the event high demand intervals are separated by significantly lower demand intervals on the same day.</td></tr>
</table>

Stakeholder	Stakeholder Feedback	EPWA's Response
Electricity Market Advisory Services (EMAS)	EMAS recommends adopting an ex-ante design as it will reduce the cost and uncertainty for Market Participants interacting with the IRCR mechanism. EMAS noted that a larger and coordinated IRCR response will benefit all consumers in the WEM by reducing the Reserve Capacity Requirement.	EPWA considers the proposed method is more robust and predictable, as an ex-ante method would risk the selection of periods that are not high demand periods.
Enel X	Enel X considers that overall, it is not clear that the benefits of changing the methodology would outweigh the costs.	EPWA considers that the proposed new approach for selecting IRCR intervals leads to a more equitable allocation of the capacity costs to customers as it is better aligned with the causer-pays principle than the current method, while still being clear and predictable.
Proposal C: Remove TDL/NTDL multipliers from the IRCR process.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Alintа Energy • Enel X • Change Energy • Perth Energy • Expert Consumer Panel • Synergy		
Karara Mining Limited	Karara Mining Limited considers the TDL/NTDL multipliers as necessary and notes that the NTDL consumers provide certainty to future network demand predictions. The price stabilisation created by NTDL consumers should continue to be incentivised through the TDL/NTDL multipliers. The EPWA paper, "Low Load Project: Stage 1 report", defines the "low demand issue" Karara Mining Limited notes that the Karara Mine Load being a constant load mitigates the "Low Demand" issue. Karara Mining Limited considers that if it is eventually decided to remove the TDL/NTDL multipliers, a mechanism should be created to recognise and reward the effects of the loads that	EPWA agrees that NTDLs contribute usefully to the SWIS, but considers that the IRCR allocation is not the place to recognise this contribution. NTDLs contribute to peak demand just as TDLs do, and IRCR will be allocated more effectively based on their contribution to peak demand.

Stakeholder	Stakeholder Feedback	EPWA's Response
	support system stability under low demand conditions, if a decision is made to remove the TDL/NTDL multipliers.	
Proposal D: Calculate IRCR on a daily basis. Set representative load for new meters based on the maximum of the median demand in the four peak intervals of any prior month.		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO • Perth Energy		
Alinta Energy	Alinta Energy provides tentative support. Alinta Energy questioned the benefits of recalculating IRCR daily and noted that prior reforms to the IRCR and prudentials under the 'Reduction of Prudential Exposure' involved substantial work.	EPWA considers that the benefits of calculating the IRCR daily outweigh the additional costs. EPWA understands that the main consideration for implementation costs is the volume of data required. Given that an amended IRCR method is being implemented, AEMO would need to automate the calculation and changing the calculation frequency will require a small (though not trivial) implementation effort.
AEMO	AEMO is supportive of more frequent calculations and: • notes that the change may have implementation issues that should be further considered in advance of the development of rule amendments; and • suggests consideration is given to calculating Reserve Capacity payments daily, as the current monthly approach arbitrarily places a higher value on capacity credits in shorter months. Notes that further detail is required to understand the operational impacts.	• See EPWA's response to the issue raised by Alinta Energy above. • Participant Peak IRCR will be calculated on a daily basis. Talks with AEMO have confirmed that the implementation effort would be manageable.

Stakeholder	Stakeholder Feedback	EPWA's Response
Proposal E: Set participant IRCR for flexible capacity based on the load shape in high ramp periods.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Alinta Energy • Expert Consumer Panel • Perth Energy • Synergy		
Synergy	Synergy suggests that the methodology used to determine the flexible capacity requirement and the allocation of costs may require monitoring to ensure that this product does not become a "proxy" for the provision of FCESS capacity.	The WEM Rules require the Coordinator to regularly review the appropriateness of the Planning Criterion, the ESS Requirements as well as the effectiveness of the WEM. These reviews will include the new flexible reserve capacity requirement.
Enel X	Enel X does not have a strong view on the preferred option. Option 1 is likely to have more impact in delivering a reduction in the ramping effect by allowing large industrial loads that do not usually contribute to the ramp, to help deliver a demand reduction and so offset the ramping. On the other hand, Option 2 is fairer because it adopts a causer pays approach whereby those that contribute to the ramp are targeted. However, notes it is likely to be more complex and so more costly to implement.	Noted
Proposal F: Set IRCR for flexible capacity based on the three days with the highest four-hour upwards ramp at any time during the year. Require AEMO to publish the forecast ramp so that consumers can monitor and respond to the signal.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Alinta Energy • Expert Consumer Panel • Enel X • Perth Energy		

Stakeholder	Stakeholder Feedback	EPWA's Response
EMAS	• EMAS recommends adopting an ex-ante design as it will reduce the cost and uncertainty for Market Participants interacting with the IRCR mechanism. Noted that a larger and coordinated IRCR response will benefit all consumers in the WEM by reducing the Reserve Capacity Requirement. • EMAS notes that Market Participants can reduce their IRCR by temporarily increasing their load (e.g. through reducing their BTM solar production) at the beginning of the Flexible IRCR assessment period.	• As noted above, EPWA does not favor the ex-ante method due to the risk of mis-forecasting system stress periods for the system as a whole. AEMO's provision of a forecast ramp should provide enough information for participants to make decisions to reduce their contribution to the ramp in order to reduce their Flexible IRCR. • EPWA notes the risk identified by EMAS regarding the ability of participants to game the Flexible IRCR allocation and has amended the calculation process to address this risk.
Enel X	Enel X is supportive of proposal F provided there is a reasonable way for DSPs to offer the flexible ramping product. DSPs must be able to respond to an AEMO direction to reduce load. The alternative approach, where participants have to conservatively anticipate when the high ramping intervals will be, requires participants to dispatch many times to reduce their exposure to flexible IRCR. This is highly costly and inefficient, as unnecessary dispatches do not contribute to a system need. If AEMO provides better instructions on when high ramping times will be, DSPs will be better able to respond.	EPWA agrees that if a DSP can respond flexibly and at short notice, then it should be eligible to receive Flexible CRC.
Proposal G: Where a DSP has: • the same Associated Loads it had in the previous year, assign CRC based on IRCR of the Associated Loads; and • different Associated Loads from – the previous year, assign CRC based on a value nominated by the Market Participant.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Expert Consumer Panel • Enel X • Perth Energy • SwitchDin		

Stakeholder	Stakeholder Feedback	EPWA's Response
AEMO	AEMO notes that the integration of multiple CRC options for DSPs is likely to add complexity, such that a single process would be preferable if the complexity of the detailed design and the cost to implement and operationalise outweighs the benefit. Requires clarification on the detailed design.	EPWA considers that the current certification method works well for single large industrial loads. The proposed additional certification method will allow DSPs that aggregate multiple smaller loads to participate in the RCM. This is expected to unlock valuable additional capacity and increase system reliability and security. However, to address the concern, EPWA has amended the approach as follows: • DSPs comprised of a single Associated Load will be allocated CRC based on the IRCR of the Associated Load less its minimum load requirement. • DSPs comprised of more than one Associated Load will be allocated CRC based on their nominated response.
AEC	The AEC does opposes the proposal to allow DSPs to nominate their CRC value on the basis that this would risk disingenuous applications that cause substantial volatility in the RCP and reliability forecast and thereby exacerbate investment uncertainty that is already a critical issue facing the WEM If implemented, this proposal should be accompanied by stringent accreditation requirements or penalties to prevent or disincentivise applicants from submitting speculative offers that are designed only to meet a capacity test.	EPWA considers that ample incentives will be put in place to prevent and disincentivise disingenuous applications, including the potential of DSP providers: • losing their reserve capacity security if no capacity is made available; • paying refunds when there is a shortfall of capacity; and • paying refunds in excess of capacity payments.
Alinta Energy	Alinta Energy does not support allowing DSPs to nominate their CRC value, considering that this would risk disingenuous applications that cause substantial volatility in the reserve capacity price and reliability forecast and thereby exacerbate investment uncertainty that is already a critical issue as the WEM transitions.	

Stakeholder	Stakeholder Feedback	EPWA's Response
Change Energy	Change Energy supports the continued approach to assign CRC to DSPs based on the IRCR of the Associated Loads less the minimum load requirement of those Associated Load. Change Energy acknowledges that the Associated Loads of some DSPs are more changeable within and between years (e.g. those of small load aggregators), and this needs to be managed. However, this already occurs and as noted by EPWA, the certification process already contemplates this. Change Energy recommends only introducing an alternative approach if significant issues are identified with the existing approach. On this basis Change Energy does not support the addition of a second DSP CRC approach at this time (Part 2 of Proposal G).	EPWA considers that the current certification method works well for single large industrial loads. The proposed additional certification method will allow DSPs that aggregate multiple smaller loads to participate in the RCM. This is expected to unlock valuable additional capacity and increase system reliability and security. EPWA further considers that the current method for assigning CRC to DSPs does not allow AEMO to adequately assess aggregations of small loads were one year's consumption is not a good predictor of the consumption in the following year.
Enel X	Enel X seeks further clarification on cases that do not clearly fall into the two options identified in EPWA's proposal G. For example, as an aggregator we are likely to have a mix of large industrial loads that, by themselves, may fall into option 1. However, these will be combined with many smaller loads that, aggregated by themselves, would fall into option 2. Further, when aggregators are certifying capacity three years in advance, we are unlikely to have certainty about the NMIs that will ultimately be included in our portfolio. As identified by EPWA, "For DSPs made up of many aggregated loads, the specific NMIs involved may not be identified at the time of certification, and only identified closer to the start of the Capacity Year". 2 Therefore, while we can commit to an aggregate level of capacity, we will not necessarily know exactly which loads will be delivering the capacity and therefore the specific NMIs involved. Enel X considers that all aggregators should fall under option 2 regardless of the size of the loads in the aggregations or if the Associated Loads have changed from the previous year. Allowing all aggregators to nominate a value for the purposes of assigning CRCs will remove barriers on aggregators to enroll any loads to	EPWA acknowledges the concern and has simplified the proposal to reduce complexity and increase clarity. To address these concern, EPWA has amended the approach as follows: • DSPs comprised of a single Associated Load will be allocated CRC based on the IRCR of the Associated Load less its minimum load requirement. • DSPs comprised of more than one Associated Load will be allocated CRC based on their nominated response.

Stakeholder	Stakeholder Feedback	EPWA's Response
	meet CRC obligations and therefore bring more capacity to the market.	
Proposal H: Remove Consumption Deviation Applications (CDAs) from the assessment of DSP CRC.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Alintа Energy • Expert Consumer Panel • Enel X • Perth Energy		
Enel X	Enel X supports the proposal to remove CDAs on the basis that aggregators will be able to nominate their own value for CRCs and so account for maintenance days within that value. Enel X notes that it would be helpful if EPWA could clarify when consumption records will be adjusted and on what basis.	EPWA confirms that consumption records adjustment would only be performed when a DSP is dispatched or tested.
SwitchDin	SwitchDin seeks more information regarding the proposed treatment of the DSP CRC if, in future, the DSP performance is affected by the application of bi-directional DOEs. SwitchDin understands the rationale for no longer allowing maintenance intervals to be excluded from consideration, and seeks to understand how the application of bi-directional DOEs would be accounted for in the measurement of actual consumption. Participants are unable to determine how DOEs are applied, and if the CDA mechanism is removed entirely it is unclear how participants will be expected to manage the risk of DOEs affecting DSP performance.	EPWA considers that DSPs should account for the potential effects of DOEs when nominating their CRC value, and notes that Western Power will need to be clear on any restrictions it places on connections to its network.

<table>
<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA's Response</th></tr>
<tr><td colspan="3">Proposal I:
Allow sites with collocated load and generation or storage to be Associated Loads of a DSP.</td></tr>
<tr><td colspan="3">The following stakeholders indicated that they 'support' or generally support the proposal:
• Alinta Energy
• Expert Consumer Panel
• Enel X
• Perth Energy
• SwitchDin</td></tr>
<tr><td>AEMO</td><td>AEMO seeks confirmation that there will not be an obligation to register generation and storage under this proposal, and that the proposal:
• is for Non-Scheduled Facilities only; and
• allows for sites containing load/generation to participate as a DSP.
AEMO seeks clarification on reference to "hybrid" and assurance that the proposal is not seeking to remove the concept of Separately Certified Component as removing this concept from the WEM Rules will require significant implementation effort across most aspects of AEMO's operations. AEMO requires clarification on the detailed design to enable assessment of the proposal.</td><td>EPWA confirms that the proposal currently relates only to Associated Loads with generation or storage, which does not exceed the mandatory registration threshold.
One of the RCM Review Outcomes is to remove the requirement to register separate components of a facility, so that the facility as a whole can be assigned a single Capability Class, but acknowledges that this may require significant implementation effort and will continue to engage with AEMO to consider how this can be done while reducing that effort.</td></tr>
<tr><td>SwitchDin</td><td>SwitchDin notes that Virtual Power Plants (VPPs) should be considered viable new sources of dispatchable capacity and the RCM Review should ensure that payments under the RCM are available to appropriately accredited VPPs.</td><td>RCM payments will be available to any Facility assigned CRC including VPPs capable of being registered as DSPs.</td></tr>
</table>

Stakeholder	Stakeholder Feedback	EPWA's Response
Proposal J: Adopt a dynamic baseline to measure DSP dispatch performance against. Continue to assess the detailed dynamic baseline methodology. Consider reducing the number of hours that DSPs can be dispatched.		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO • Perth Energy • Expert Consumer Panel • SwitchDin • Enel X		
AEMO	AEMO is generally supportive of the proposal with suggestions for improvement. AEMO proposes enabling a DSP to nominate the number of hours. AEMO notes that a dynamic baseline would need to be flexible enough to account for a participant responding to IRCR signals during the Summer and either responding or not responding on the same day as being dispatched.	EPWA notes that, if a participant chooses to reduce consumption to reduce its IRCR exposure during a baseline period, its baseline for DSP dispatch would also be reduced from what it would have been had the participant not sought to manage its IRCR.
Alinta Energy	Alinta Energy does not support the proposal. Alinta Energy does not consider that the proposal to reduce the maximum number of hours a DSP can be dispatched is warranted nor supported by sufficient evidence to revert from the status quo which harmonised the availability requirements for Supply-Side and Demand-Side Capacity Resources (which was developed through significant and detailed consultation and analysis). Alinta Energy considers that the proposal could lead to an inefficient amount of DSP to enter the market and earn a substantive capacity income (compared to its fixed costs) while having very little risk of actually needing to perform. Alinta energy considers that these fundamental issues associated with the treatment of DSP under the Market Rules warrant prompt	EPWA considers that any change to the DSP minimum dispatch requirement should reflect the needs of the SWIS and result in overall benefit to the WEM, and that a requirement consistent with the expected load duration curve (LDC) would be appropriate. See section 2.2.2.

Stakeholder	Stakeholder Feedback	EPWA's Response
	further consideration with a view to ultimately ensuring unnecessary costs are not incurred.	
Enel X	Enel X strongly supports the move to measuring response against a dynamic baseline. Enel X suggests the CAISO 10/10 baseline, used by demand side resources offering supplementary reserve capacity, as a dynamic baseline approach to be considered. Enel X notes that reducing the required dispatch hours from 200 would reduce the potential costs and risks of participating and allow more loads to participate. Enel X suggests reducing to 20 hours, as this is more reflective of the number of hours that DSPs are likely to be dispatched and of value to the system. A limit of 20 hours will help to encourage new demand side capacity to participate. Enel X encourages EPWA to consider the duration requirements for DSP. Currently, a facility must be available to provide reserve for at least 12 hours (Rule 4.10.1(f)(iii)). We propose this be reduced to four hours, again to be more reflective of the expected value of demand side resources during grid stress events. A twelve hour dispatch is unachievable for many loads. For example, a refrigeration warehouse can only reduce load for a few hours before their goods start to spoil. Reducing the duration requirements to four hours would allow different types of load to provide valuable capacity for the times when the system is most under stress.	The detail of the dynamic baseline will be developed during Stage 3 of the RCM Review and will be based on analysis undertaken under the Demand Side Response Review. See section 2.2.2 for further analysis and detail on the hours a DSP must be available. EPWA considers that DSP providers can aggregate Associated Loads so each Load has to be available for 4 hours only. Therefore, EPWA considers that limiting the hours a DSP must be available each day below 12 hours is unnecessary and may undermine the RCM reliability objectives.
SwitchDin	SwitchDin considers a dynamic baseline should more accurately reflect measurement against the counterfactual of what would otherwise have been consumed, provided the dynamic baseline is set appropriately. SwitchDin considers that requiring DSPs to be available for dispatch for up to 200 hours each year would be an unnecessary	See responses above.

<table>
<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA’s Response</th></tr>
<tr><td></td><td>barrier to participation. SwitchDin notes that the minimum availability requirement for DSPs should be based on historical experience, plus a margin of safety to allow for years when demand for the services of DSPs are higher than anticipated. SwitchDin notes that they do not have the data nor the analysis to nominate an appropriate number of hours.</td><td></td></tr>
<tr><td>Synergy</td><td>Synergy considers that the proposal to reduce the availability requirement for DSP may be appropriate. However, Synergy is strongly of the view that the compensation paid to DSP capacity should also be reduced in line with any reduction in the availability requirement. Synergy notes further exploration of the requirements and incentives for DSP facilities may be considered by the Demand Side Response Working Group.</td><td>See responses above.</td></tr>
<tr><td colspan="3">Proposal K:
Require facilities holding flexible Capacity Credits to be tested for start/stop times and ramp capability.
Allow Facilities to pass flexible capacity tests by observation.
Require AEMO to schedule tests of flexible capacity characteristics to coincide with tests for peak capacity.</td></tr>
<tr><td colspan="3">The following stakeholders indicated that they ‘support’ or generally support the proposal:
• AEMO
• Enel X
• Alinta Energy
• Perth Energy
• Expert Consumer Panel</td></tr>
<tr><td>AEMO</td><td>AEMO generally supportive of the proposal with suggestions for improvement.
AEMO suggests considering mandatory participation in Fast Start Inflexibility Profiles.</td><td rowspan="2">Facilities holding flexible Capacity Credits will be required to be tested for start, stop, restart, and minimum running times; ramp capability; and minimum stable loading level.
To address the stakeholders comments on this proposal, the following clarifications have been included in the relevant Review Outcome:</td></tr>
<tr><td>Enel X</td><td>Enel X considers that testing for flexible capacity should be approached in the same way as for regular DSP capacity.</td></tr>
</table>

Stakeholder	Stakeholder Feedback	EPWA's Response
Perth Energy	Perth Energy supports the proposal to test compliance of flexible plant by observation. Perth Energy does not necessarily see this being undertaken at the same time as capacity testing as the two obligations are somewhat different. Perth Energy suggests that dual fuel, distillate-natural gas plants, should be allowed to demonstrate their flexibility compliance on the fuel that more fully reflects their expected flexible operating pattern.	• The minimum requirements to be met by Flexible Capacity will be set through a process that includes consultation. • Flexible capacity may be tested through observation. • When scheduling Reserve Capacity tests, AEMO will be required to consider whether it would make sense to schedule a Flexible Capacity test at the same time as a Peak Capacity test.
Proposal L: Adjust Reserve Capacity Testing for DSPs to reflect a shift to a dynamic dispatch baseline. Require AEMO to consider the expected baseline when scheduling DSP tests. Treat a failed test as the beginning of a forced outage, rather than a permanent reduction of Capacity Credits.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Expert Consumer Panel	• Enel X	• Perth Energy
Alinta Energy	Alinta Energy does not support the proposal and considers that testing should reflect the facility's accredited capacity, subject to ambient conditions, like other capacity types.	EPWA considers that DSP tests should be conducted under conditions similar to those that AEMO expects would apply when actual DSP dispatch is most likely. This will ensure that the dynamic baseline against which the tests are assessed aligns with that expected for actual DSP dispatch. A DSP failing a test will pay refunds for the reduction not achieved until it passes a subsequent test.
Enel X	Enel X agrees that the testing regime for DSPs will need to change to reflect the use of dynamic baselines. However, Enel X considers that the testing regime could be improved to incentivise DSP participation whilst ensuring the integrity of DSP capacity. It is not clear how the obligations and penalties of the two existing tests for DSP (the annual test and the verification test) interact, and why two tests are necessary. The	EPWA considers that that the two tests already provide a suitable balance between confidence in performance and costs to participants. EPWA further considers that the treatment of a failed test as the beginning as a forced outage is fair and provides a suitable

Stakeholder	Stakeholder Feedback	EPWA's Response
	testing regime must strike an appropriate balance between ensuring the capacity is "real" and incentivising DSP resources to participate. In Enel X's view, one annual test is an appropriate balance as this provides sufficient certainty to AEMO that a resource is capable without using too many hours of that resource's dispatch capability. Regarding the treatment of failed tests as the beginning of a forced outage – Enel X is concerned that this approach does not recognise that the primary purpose of generation and demand side resources are fundamentally different, and will unfairly penalise customer resources that may not be able to quickly remedy the unavailability.	balance between penalties and incentive to provide the service for the rest of the capacity year.
Proposal M: Amend the outage planning process so that AEMO considers availability of both peak and flexible capacity when assessing and approving outages		
The following stakeholders indicated that they 'support' or generally support the proposal: • Expert Consumer Panel • Perth Energy		
Alinta Energy	Alinta Energy provides tentative support. Alinta Energy questions whether additional amendments are required to the criteria AEMO must consider when scheduling outages. Alinta Energy supports AEMO having discretion to decide when to schedule outages and understand that overly prescriptive requirements are contributing to the current difficulty in generators scheduling outages, ahead of the new criteria being introduced in the new WEM. Alinta Energy encourage measures that would support AEMO using its discretion to permit outages proceeding where deferring would present a greater risk to supply in the short to medium term.	EPWA considers that explicitly accounting for flexibility in the outage planning process is important for system security. Therefore, AEMO should be required to account for both flexible and peak capacity availability when assessing outages.

Stakeholder	Stakeholder Feedback	EPWA's Response
Proposal N: Require flexible capacity holders to lodge outages relating to capability to provide flexible capacity.		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO • Expert Consumer Panel • Perth Energy		
AEMO	AEMO generally supports the proposal, but notes that further detail is required to understand whether there will be a separate refund regime and, therefore, the operational impact on AEMO.	As FCESS outage notification is currently separate to energy outage notification, there will not be a significant increase in complexity required to encompass Flexible Capacity.
Alinta Energy	Alinta Energy provides tentative support. Alinta Energy questions whether flexible capacity requires a separate outage regime, noting the additional complexity. It is Alinta's expectation that the instances where facilities are not able to provide flexible capacity but are able to provide peak capacity would be infrequent.	EPWA notes that it is difficult to identify how often such an outage might occur. However, the current outage regime already requires participants to notify outages of FCESS capability separately from energy capability, so there will not be a significant increase in complexity required to encompass Flexible Capacity.
Proposal O: Allow DSP owners to manage their own outage schedules, without participating in the outage planning regime. Adjust DSP availability measurement to use actual demand at Associated Loads rather than the Relevant Demand.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Expert Consumer Panel • Enel X • Perth Energy		
Alinta Energy	Alinta Energy does not support the proposal. Alinta Energy is uncertain whether this would impact the reserve margins that are crucial to scheduled facilities being able to conduct outages. If DSP availability measurements are adjustable, Alinta Energy would question whether they should refund Capacity Credits like Scheduled Generators where they are not able to provide their full capacity.	EPWA considers that, because the effect of self-scheduled DSP outages will be reflected in their baselines, there is sufficient incentive to schedule outages in non-peak periods.

Stakeholder	Stakeholder Feedback	EPWA’s Response
Proposal P: Capacity refunds for both peak capacity and flexible capacity will be paid from a single pool of capacity payments.		
The following stakeholders indicated that they ‘support’ or generally support the proposal: • AEMO • Alinta Energy		
AEMO	AEMO generally supports the proposal, but requires further detail to understand the operational impacts.	
Perth Energy	Perth Energy considers that the proposal requires further work. Perth Energy notes that a plant that experiences high levels of unavailability can be required to refund its full reserve capacity payments and, because of the dynamic refund charge, this may occur well before the end of the capacity year. The risk in having all refunds paid in this way is that there may be limited incentive for a plant to continue to provide the flexibility service during August or September when the requirement may be high. Some refund obligation must be left with flexible providers through to the end of the capacity year. This may require flexibility refunds to be capped in some way.	EPWA has amended the approach (reflected in Review Outcome 7) to implement separate refund pools for Peak Capacity and Flexible Capacity. See section 2.2.3.
Synergy	Synergy considers that Facilities should only pay refunds based on the product that they are not providing at the refund rate that applies to that product. The refund rate that should be applied if a facility is able to provide the peak capacity product should be the refund rate applicable to the reliability of the flexible product. Synergy considers that refunds should be calculated based on two separate payment pools, one for each of the capacity products.	See response above.

Stakeholder	Stakeholder Feedback	EPWA's Response
	The proposed approach of two capacity pools will ensure that the refunds collected for each of the products can be redistributed to Market Participants in relation to the product that has been paid for.	
Proposal Q: Calculate a dynamic refund multiplier for flexible capacity based on a comparison of the actual ramp requirement in the interval and the ramp rate used to set the flexible capacity RCR. Apply the greater of the peak and flexible multipliers to refunds for facilities supplying both capacity types. Require AEMO to publish the projected load ramp rate alongside the load forecast.		
The following submissions indicated that they 'support' or generally support the proposal: • AEMO		
AEMO	AEMO generally supports the proposal, but requires further detail is to understand the operational impacts.	
Alinta Energy	Alinta Energy provides tentative support. Alinta Energy questions whether the additional complexity of a separate refund regime is required for flexible capacity as Alinta Energy expects low reserve conditions for peak capacity would typically coincide with low reserve conditions for flexible capacity and that the instances where facilities are not able to provide flexible capacity but are able to provide peak capacity would be infrequent.	EPWA considers that it is necessary to have separate refund pools for Peak Capacity and Flexible Capacity. Therefore, separate refund regimes are required. See section 2.3.3. A dynamic refund multiplier for flexible capacity will be calculated based on a comparison of the actual ramp requirement in the interval and the ramp rate used to set the flexible capacity RCR.
Perth Energy	Perth Energy does not support setting refunds based on the greater of the peak and flexible refunds for plants that supply both. These are different services and they are expected to be delivered in different seasons. The refund mechanism must ensure that each service is appropriately incentivized and that the incentive to deliver flexibility remains for the full capacity year.	EPWA has amended the approach (reflected in Review Outcome 7) to implement separate refund pools for Peak Capacity and Flexible Capacity. See section 2.2.3.

Stakeholder	Stakeholder Feedback	EPWA's Response
Proposal R: Amend the Maximum Facility Refund for DSPs to include the DSM Reserve Capacity Security.		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO • Perth Energy • Alinta Energy • Synergy		
AEMO	AEMO generally supports the proposal, but requires further detail is to understand the operational impacts. AEMO requires further detail to understand if DSM Reserve Capacity Security will be called upon or if it is to be an input into the calculation. Effort taken in the detailed design phase will be necessary; otherwise significant complexity will likely arise during implementation.	EPWA acknowledges that the proposed approach is difficult to implement and has amended the approach (reflected in Review Outcome 7) to apply a Maximum Facility Refund for DSPs of 125% of the total capacity payments. This matches the reserve capacity security at risk without the potential difficulties associated with drawing on part of the security. See section 2.3.3.
Enel X	Enel X considers that the existing penalty and refund regime, combined with the testing regime Enel X proposes in response to Proposal L, is robust enough to deter any participant from taking on a capacity obligation speculatively or failing to deliver contracted capacity. In Enel X's view the risk of losing capacity credits is sufficient incentive to ensure that capacity is available. Enel X does not consider that DSP should be penalised simply for being a more economic resource, noting that DSP dispatches are not without cost. Enel X considers that a clearer policy rationale for this proposal is needed if the change is to be made.	EPWA maintains that the capital light nature of DSPs means that additional incentives (such as increasing the maximum capacity refund for DSPs to 125% of potential capacity payments) are required. See section 2.3.3.

Stakeholder	Stakeholder Feedback	EPWA's Response
Proposal S: Distribute collected capacity refunds to consuming participants rather than other capacity providers.		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO • Perth Energy • Expert Consumer Panel • Change Energy • Karara Mining Limited • Synergy		
AEMO	AEMO is generally supportive of the proposal with suggestions for improvement. AEMO suggests to consider including a required action if a provider fails to provide for a full year; for example, include unavailability / non-provision as part of NCESS trigger.	EPWA notes the suggestion to include long-term unavailability of certified capacity as an NCESS trigger. However, this was not the objective of the propos.
Alinta Energy	Alinta Energy does not support the proposal. Alinta Energy recommends that EPWA considers whether retailers would redistribute any rebates to customers to offset the SRC or NCESS costs. If not, there may be little benefit to progressing any reforms to rebate allocations. Alinta Energy also strongly oppose the redistribution of collected capacity refunds and recommend that EPWA and the working group investigate other potential reforms to address this issue for the reasons below: • EPWA's rationale incorrectly assumes that forced outages will be the sole cause of SRC and NCESS, and that all forced outages will cause additional SRC and NCESS costs or undermine reliability outcomes. (Additional detail provided in Alinta Energy's submission.) • EPWA's rationale assumes that retailers will pass-through the rebates to customers. This is not certain, as the WEM Rules do not regulate how retail rates are set, and many customers	EPWA considers that, for the following reasons, capacity refunds should be distributed to participants responsible for loads, rather than other capacity providers: • Loads fund the capacity products in the first place and they, as any consumer would expect, should receive refunds in the event they do not receive all of the product they have paid for; • generators receiving capacity refunds do so without providing any additional level of service; • failure of generators to provide capacity results in triggering NCESS or SRC, effectively making consumers pay twice; • a competitive retail market will ensure that at least some of the refunds make their way to consumers; • the capacity mechanism is designed to provide sufficient incentive for new investment without an additional revenue stream from refund rebates; and

Stakeholder	Stakeholder Feedback	EPWA's Response
	are on regulated rates. (Additional detail provided in Alinta Energy's submission.) • The proposal has not been adequately interrogated, especially compared to the current arrangements, implemented in 2017. (Additional detail provided in Alinta Energy's submission.) • Re-allocating all rebates to customers would make the current refund regime excessively punitive for generators, especially given low reserves over the medium term. (Additional detail provided in Alinta Energy's submission.)	• rebating refunds to consumers aligns with the distribution of Reserve Capacity Security drawdowns. • EPWA held an additional RCM Review Working Group on 13 July 2023 to further discuss the proposal. The views during the meeting were finely balanced between support for and opposition to the proposal. See section 2.3.3 for a summary of the meeting. • EPWA notes that lower reserves due to lower excess capacity results in a higher value placed on each Capacity Credit resulting in higher capacity payments. EPWA considers that it is reasonable that it also results in higher refund payments for Forced Outages.
Bluewaters NewGen Power Kwinana (NewGen)	Bluewaters and NewGen do not agree with the proposal. Bluewaters and NewGen are concerned that the proposal does not appear to have undergone the same level of investigation, scrutiny and industry engagement as other proposals presented in the consultation paper and has only been briefly discussed at RCMRWG and MAC sessions. The issue of capacity refund distribution has previously been reviewed and did change from consumers to generators on 1 October 2017. The background work supporting this previous change was more detailed and robust, than what is currently being contemplated. Bluewaters and NewGen consider that the Proposal rationale: • ignores the increased value of generation capacity that is available during times of reduced capacity in the WEM; and • implies that that reduced generator availability is the only driver of SRC and NCESS procurement while consumer demand also influences SRC/NCESS requirements. Bluewaters and NewGen consider that the current dynamic capacity refund mechanism and refund distribution regime work in	See response above.

Stakeholder	Stakeholder Feedback	EPWA's Response
	parallel to strengthen incentives for plant availability and competition in the energy market. Proceeding with the proposal will remove an incentive associated with plant availability and potentially reduces competition in the energy market.	
Shell Energy	Shell Energy strongly suggests that the proposal should not proceed. In Shell Energy's view, the case for change has not been established and the level of scrutiny of Proposal S has been insufficient. Consultation and assessment at both the Reserve Capacity Mechanism Review Working Group (RCMRWG) and the Market Advisory Committee (MAC) was not sufficient and there has been no assessment of the merits of the proposed change. The future impact of the proposed change is not quantified, and the economic efficiency impacts were not assessed. Upon examination, Proposal S appears inconsistent with both the WEM objectives and the broader changes to the RCM. In its submission, Shell Energy provides its own assessment of: • the significance of RCM refund recycling to generators; • the link between refund recycling and AEMO tendering for SRC; • the rational for the current refund recycling arrangements; • how the RCP does not take into account the actual RCM supply; • recycling refunds to generators as a proxy for dynamic RCP pricing; and • tighter RCM supply increasing the need for dynamic RCP. Sell Energy concludes that • Any further consideration of Proposal S must be supported by analysis as to whether competitive and regulatory arrangements are in place to ensure that recycled capacity	See response above.

Stakeholder	Stakeholder Feedback	EPWA's Response
	funds are applied to SRC, NCESS, or passed back to consumers. • Dynamic capacity refunds and capacity recycling to generators support more dynamic price signals about actual demand and supply conditions at the time that capacity credits are provided. This helps to offset errors in the 2-year forward pricing currently, which gives rise to situations whereby RCPs are set too low if plant outages are higher than expected in the capacity year (i.e., supply of capacity credits is lower than anticipated) and ensures that remaining plant is available to meet reliability requirements. • Changes to capacity refund recycling should only be considered in the context of introducing dynamic RCPs and better alignment of RCP levels with RCM outcomes, as well as better alignment between RCP levels and the economic value of RCM supplied. • Given the transition to intermittent generation and energy storage facilities with only limited energy supplies (2 to 4 hours), this is not the time to reduce future revenue streams for existing generation facilities that provide firm capacity and are not energy constrained to the same extent as energy storage facilities. Recycling capacity refunds to generators provides a strong signal for plants to be available, which is critical to maintaining supply when there are significant plant outages (as occurred with the unavailability of the Collie Power Station for several months due to coal supply concerns).	

Stakeholder	Stakeholder Feedback	EPWA's Response
Proposal T: Amend the target EUE percentage in the second limb of the RCM Planning Criterion to 0.0002% of annual energy consumption.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Expert Consumer Panel • Perth Energy		
AEC	The AEC does not agree with the proposed changed to a 0.0002% EUE target in the Planning Criterion and opposes to this being included in the RLM as the assumed level of system reliability as it unnecessarily causes the reliability of the fleet of intermittent generators to be based on much fewer intervals, creating a needless risk of substantial volatility and investment uncertainty.	EPWA considers that a 0.0002% target is appropriate: • While the use of the 0.0002% target does reduce the system stress periods included in the RLM, the analysis shows an adequate number of intervals continue to drive the CRC allocation in order to prevent volatility in CRC allocations between years. • It is reasonable for a small, isolated power system such as the SWIS to have a higher reliability target than a large, interconnected power system such as the NEM. • A 0.0002% target more closely aligns the reserve margin and EUE target arms of the planning criterion. However, the commencement date for this change will be considered further, taking into account concerns raised regarding its potential impact on the MT PASA and outage scheduling. See section 2.4.1.
Alinta Energy	Alinta Energy opposes the proposal, noting that: • the market has not been designed for the second limb of the planning criterion to bind; • the measure is extremely conservative, being 3 times more conservative than the interim measure currently applied in the NEM, and it is not appropriate to assume the system would have such a high standard in the RLM; • the rationale is not based on a value of customer reliability;	See response above.

Stakeholder	Stakeholder Feedback	EPWA's Response
	• the WEM is a small and a very 'peaky' system, making an EUE target less relevant; and • per the forecast, it appears the proposed EUE is very unlikely to bind, meaning the only practical impact of the reform would be to the RLM. Alinta Energy considers that the proposed EUE target is inappropriate to apply to the RLM: • it assumes reliability will be higher compared to the SWIS forecast shortfalls over the medium term; and • arbitrarily and unnecessarily reduces the number of intervals used to calculate the capacity value of the fleet, meaning it will become more volatile for no commensurate benefits to the investment signals or accuracy of the model. Further, Alinta Energy considers the sample of periods used to test volatility is not large enough to give us confidence that more erratic fluctuations will not occur in future.	
Collgar	Collgar does not support a change to a EUE target of 0.0002% and is concerned that a target of 0.0002% will have a material impact on volatility. Collgar supports retaining the existing 0.002% EUE.	See response above.
Expert Consumer Panel	The Expert Consumer Panel provide qualified support, subject to highlighting the need to ensure that changes to this reliability standard do not unnecessarily increase costs to consumers. The Expert Consumer Panel suggests that the setting of this EUE limb of the planning criterion be re-examined closer to when this limb is likely to affect the quantity and costs of WEM reserve capacity.	EPWA notes that the WEM Rules require that the Coordinator periodically reviews the appropriateness of the Planning Criterion, including the EUE target.
Perth Energy	Supports the proposal and also supports raising the reserve capacity target during the transformation process to minimize	EPWA acknowledges the request and notes that Stage 1 of the RCM Review has increased the reserve margin and therefore the

Stakeholder	Stakeholder Feedback	EPWA's Response
	customer supply risk arising from failure of new capacity to be delivered on time.	Reserve Capacity Target. EPWA considers that further raising the Reserve Capacity Target would be therefore unnecessary.
Proposal U: The WEM Rules will continue to 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 separate BRCP will be calculated for each of the peak capacity and flexible capacity products. The two capacity products may have a different underlying reference technology, not just different cost components. The Coordinator will review the appropriate reference technology for each capacity product, and consequently the use of gross CONE or net CONE to set the BRCP. The Coordinator must review the reference technology and the use of a gross or net CONE approach at least every five years, and may review it more frequently if the Coordinator considers that it has changed considerably.		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO • Expert Consumer Panel • Perth Energy • Synergy		
AEC	The AEC considers that there is no benefit in the Coordinator determining the reference technology used in the BRCP methodology. Instead, the Australian Energy Council considers that the ERA should continue to consider the appropriate reference technology under clause 4.16 of the WEM Rules, noting that the ERA is independent and has the capability to undertake this role. The AEC does not agree with a net CONE approach and instead supports retaining the gross CONE approach. The AEC's main concern with the net CONE approach is that it risks creating 'missing money' for generators and consider this can adversely impact the investment case for flexible generation and storage.	EPWA considers that, at this early stage, the setting of the reference technologies is a market development issue and part of the energy transition. In a way, this is a natural progression of the RCM Review. Therefore, in this instance the reference technologies should be reviewed by the Coordinator. The responsibility for this can be examined once the relevant policies have been fully implemented and bedded down. EPWA notes that the Coordinator's review of the appropriate reference technologies will include a review the appropriateness of using a gross CONE or net CONE. EPWA also notes that the review will include adequate stakeholder consultation.

Stakeholder	Stakeholder Feedback	EPWA's Response
Alinta Energy	Alinta Energy provides tentative support. Alinta Energy continues to oppose the possibility of net CONE pricing but recognises the proposal as a compromise, noting stakeholder feedback.	See response above.
Collgar	Collgar does not support the potential adoption of a net CONE and supports retaining a gross CONE. A net CONE will likely result in additional complexity and will likely result in revenue insufficiency for generators. A net CONE approach would likely result in a requirement for an additional mechanism to compensate for this missing revenue. A gross CONE will likely have an adverse impact on new entrance to the WEM.	See response above.
Synergy	Synergy supports a different BRCP being applied to the flexible capacity product and consideration of the potential difference in the reference technology. Synergy considers that a review of the appropriateness of the reference technology at least every five years appears to be appropriate and should also consider ensuring that the BRCP covers all efficient costs that are expected to be incurred by facilities that are not recoverable in the other markets as well as ensuring that facilities not expected to be dispatched can recover all efficient market costs. Synergy reiterates its concerns with the appropriateness and complexities of the potential use of net CONE to determine the BRCP.	See response above.