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

Meeting Agenda

Meeting Title:	Market Advisory Committee (MAC)
Date:	Thursday 20 July 2023
Time:	9:30 AM – 11:30 AM
Location:	Online, via TEAMS.

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda • Conflicts of interest • Competition Law	Chair	Noting	2 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	Minutes of Meeting 2023_06_08	Chair	Decision	2 min
4	Action Items	Chair	Noting	2 min
5	Market Development Forward Work Program	Chair/Secretariat	Discussion	5 min
6	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Noting	5 min
	(b) Reserve Capacity Mechanism Review Working Group (RCMWG)	Chair/Secretariat	Noting	5 min
	(c) Demand Side Response Working Group (DSRWG)	DSRWG Chair	Noting	5 min
7	Rule Changes			
	(a) Overview of Rule Change Proposals	Chair/Secretariat	Noting	2 min
8	Terms of Reference for the WEM Investment Certainty (WIC) Review	Chair	Discussion	10 min
9	Supplementary Reserve Capacity Review	Chair/Secretariat	Noting	10 min
10	Reserve Capacity Mechanism Review Stage 2 – Information Paper	Chair/Secretariat	Discussion	60 min
11	General Business	Chair	Discussion	10 min
	Next meeting: 9:30am Thursday 31 August 2023			

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the MAC (**Members**) note their obligations under the *Competition and Consumer Act 2010* (**CCA**).

If a Member has a concern regarding the competition law implications of any issue being discussed at any meeting, please bring the matter to the immediate attention of the Chairperson.

Part IV of the CCA (titled "Restrictive Trade Practices") contains several prohibitions (rules) targeting anti-competitive conduct. These include:

(a) **cartel conduct**: cartel conduct is an arrangement or understanding between competitors to fix prices; restrict the supply or acquisition of goods or services by parties to the arrangement; allocate customers or territories; and or rig bids.

(b) **concerted practices**: a concerted practice can be conceived of as involving cooperation between competitors which has the purpose, effect or likely effect of substantially lessening competition, in particular, sharing Competitively Sensitive Information with competitors such as future pricing intentions and this end:

- a concerted practice, according to the ACCC, involves a lower threshold between parties than a contract arrangement or understanding; and accordingly; and
- a forum like the MAC is capable being a place where such cooperation could occur.

(c) **anti-competitive contracts, arrangements understandings**: any contract, arrangement or understanding which has the purpose, effect or likely effect of substantially lessening competition.

(d) **anti-competitive conduct (market power)**: any conduct by a company with market power which has the purpose, effect or likely effect of substantially lessening competition.

(e) **collective boycotts**: where a group of competitors agree not to acquire goods or services from, or not to supply goods or services to, a business with whom the group is negotiating, unless the business accepts the terms and conditions offered by the group.

A contravention of the CCA could result in a significant fine (up to $500,000 for individuals and more than $10 million for companies). Cartel conduct may also result in criminal sanctions, including gaol terms for individuals.

Sensitive Information means and includes:

(a) commercially sensitive information belonging to a Member's organisation or business (in this document such bodies are referred to as an Industry Stakeholder); and

(b) information which, if disclosed, would breach an Industry Stakeholder's obligations of confidence to third parties, be against laws or regulations (including competition laws), would waive legal professional privilege, or cause unreasonable prejudice to the Coordinator of Energy or the State of Western Australia).

Guiding Principle – what not to discuss

In any circumstance in which Industry Stakeholders are or are likely to be in competition with one another a Member must not discuss or exchange with any of the other Members information that is not otherwise in the public domain about commercially sensitive matters, including without limitation the following:

(a) the rates or prices (including any discounts or rebates) for the goods produced or the services produced by the Industry Stakeholders that are paid by or offered to third parties;

(b) the confidential details regarding a customer or supplier of an Industry Stakeholder;

(c) any strategies employed by an Industry Stakeholder to further any business that is or is likely to be in competition with a business of another Industry Stakeholder, (including, without limitation, any strategy related to an Industry Stakeholder's approach to bilateral contracting or bidding in the energy or ancillary/essential system services markets);

(d) the prices paid or offered to be paid (including any aspects of a transaction) by an Industry Stakeholder to acquire goods or services from third parties; and

(e) the confidential particulars of a third party supplier of goods or services to an Industry Stakeholder, including any circumstances in which an Industry Stakeholder has refused to or would refuse to acquire goods or services from a third party supplier or class of third party supplier.

Compliance Procedures for Meetings

If any of the matters listed above is raised for discussion, or information is sought to be exchanged in relation to the matter, the relevant Member must object to the matter being discussed. If, despite the objection, discussion of the relevant matter continues, then the relevant Member should advise the Chairperson and cease participation in the meeting/discussion and the relevant events must be recorded in the minutes for the meeting, including the time at which the relevant Member ceased to participate.

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

Minutes

Meeting Title:	Market Advisory Committee (MAC)
Date:	8 June 2023
Time:	9:30am –11:30am
Location:	Microsoft Teams

Attendees	Class	Comment
Sally McMahon	Chair	
Martin Maticka	Australian Energy Market Operator (AEMO)	
Toby Price	AEMO	Proxy for Dean Sharafi
Mark McKinnon	Network Operator	Proxy for Zahra Jabiri
Genevieve Teo	Synergy	
Noel Schubert	Small-Use Consumer Representative	
Christopher Alexander	Small-Use Consumer Representative	
~~Geoff Gaston~~	~~Market Customer~~	
Timothy Edwards	Market Generator	
Jacinda Papps	Market Generator	
Adam Stephen	Market Generator	
Paul Arias	Market Generator	
Peter Huxtable	Contestable Customer	
Patrick Peake	~~Perth Energy~~ Market Customer	
Noel Ryan	Observer appointed by the Minister	
Rajat Sarawat	Observer appointed by the Economic Regulation Authority (ERA)	

Also in Attendance	From	Comment
Dora Guzeleva	MAC Secretariat	Observer
Laura Koziol	MAC Secretariat	Observer
Shelley Worthington	MAC Secretariat	Observer
Grant Draper	Marsden Jacob Associates (MJA)	Presenter

Apologies	From	Comment
Geoff Gaston	Change Energy	
Dean Sharafi	AEMO	
Zahra Jabiri	Western Power	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am with an Acknowledgement of Country. The Chair noted that MAC members are to participate in the interests of the stakeholder group they represent.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance and apologies as listed above.	
3	**Minutes of Meeting 2023_04_20** The MAC accepted the minutes of the 20 April 2023 meeting as a true and accurate record of the meeting, subject to correcting Mr Stephen’s name in the list of attendance. **Action: The MAC Secretariat to publish the minutes of the 20 April 2023 MAC meeting on the Coordinator’s Website as final.**	**MAC Secretariat**
4	**Action Items** The paper was taken as read. The MAC noted that there were no open action items.	
5	**Market Development Forward Work Program** The paper was taken as read. • Mrs Papps questioned the value of undertaking the MAC Review at this time, given the large workload under the Wholesale Electricity Market (WEM) reform program. The Chair suggested discussing this under Agenda Item 10. • Mrs Papps suggested that a roadmap needs to be developed of the priorities for the WEM reform program.	
6	**Update on Working Groups**	
	(a) AEMO Procedure Change Working Group (APCWG) The paper was taken as read. Mr Maticka noted an APCWG meeting was held 6 June 2023. The purpose was to discuss upcoming Procedure Change Proposals to amend the WEM Procedure: Supplementary Capacity; and the WEM Procedure: Reserve Capacity Security. .	
	(b) RCM Review Working Group (RCMRWG) Update	

Item	Subject	Action

The paper was taken as read.

The Chair noted that MAC members are being asked to note the updates on activities since the last MAC meeting, including the:

- minutes from the RCMRWG meeting on 22 March 2023; and
- publication of the RCM Review: Information Paper (Stage1) and Consultation Paper (Stage 2) on 3 May 2023.

Ms Guzeleva noted that a record number of submissions were received on the RCM Review: Consultation Paper (Stage 2), including from respondents who had not previously provided submissions, and noted:

- the consultation period had been extended by a week and just closed two days ago, so submissions had not yet been assessed;
- stage 1 of the RCM Review was now complete from a policy perspective and drafting of the Amending Rules had commenced; and
- another meeting of the RCMRWG will be scheduled at a later date.

(c) Demand Side Response Working Group (DSRWG) Update

The Chair noted that MAC members are being asked to note the updates on activities since the last MAC meeting including the minutes from the DSRWG meeting on 10 May 2023.

Ms Guzeleva noted that:

- the DSRWG consisted of around 20 members, including members who had not previously participated in other MAC working groups, and there was considerable interest in ensuring that the demand side achieves its potential and adds value in the market;
- a DSRWG meeting was held on 7 June 2023 and the minutes from that meeting would be available soon. The meeting covered two topics:
  - access and connection arrangements for load; and
  - hybrids and how they participate in the RCM and in the WEM more generally;
- there was interest regarding how load would be connected in constrained parts of the network in the future and the interaction with the WEM, if load is connected under run back schemes;
- with regard to hybrids there was discussion about metering and allowing participants to have a choice of alternative arrangements for the connection of hybrids, containing loads, to ensure that value is added without double dipping; and
- further meetings would be held in July and August 2023 and the MAC would be updated accordingly..

Item	Subject	Action
7	**Rule Changes** **(a) Overview of Rule Change Proposals** The paper was taken as read. Ms Guzeleva noted that the following would be published by 30 June 2023: • a Draft Rule Change Report for RC_2014_05, which was proposed by the IMO and deals with reduced frequency of the review of Energy Price Limits and the Maximum Reserve Capacity Price; • a Draft Rule Change Report for RC_2018_03, which was proposed by Collgar and deals with the Capacity Credit allocation for methodology for Intermittent Generators; and • an Extension Notice for RC_2019_01, which was proposed by EnelX and deals with the Relevant Demand calculation. The deadline for publishing the Draft Rule Change Report for RC_2019_01 will be extended to September 2023 because its subject matter is addressed in stage 2 of the Reserve Capacity Mechanism (RCM) Review. The date will align with the timing for publishing the Final Rule Change Report for RC_2019_03, which is the ERA's proposal to amend the method for assigning Certified Reserve Capacity to Intermittent Generators.	
8	**Draft Cost Allocation Review Information Paper** The MAC noted the minutes from the Cost Allocation Review Working Group (CARWG) meeting on 9 May 2023 and that EPWA had circulated a draft of the Cost Allocation Review Information Paper for discussion by the MAC. Ms Guzeleva noted that the Cost Allocation Review Consultation Paper was published in December 2023, that submissions closed in February 2023, and that EPWA assessed the submissions and held a number of CARWG meetings to discuss the remaining issues. The Chair asked Ms Guzeleva to lead the MAC through a discussion of the Review Outcomes in the Information Paper. Ms Guzeleva indicated that the Information Paper will be the final paper for the review and asked the MAC for any final comments before it is published on 15 June 2023. Market Fees: Ms Guzeleva noted that the conclusion was not to change the allocation of Market Fees because there was no benefit of doing so but there would be costs associated with making changes. Ms Guzeleva noted that there was a question in the Consultation Paper about whether Electric Storage Resources (ESR) should be allocated Market Fees based only on injection or withdrawal from the system.	

Item	Subject	Action
	Ms Guzeleva indicated that AEMO made some strong arguments as to why it may not be a good idea to treat ESR, particularly hybrids containing ESR, differently so the Review Outcome is to treat ESR the same as generators, for which Market Fees are allocated based on both injections and withdrawals. The MAC did not provide any comments or raise any concerns regarding the Review Outcomes for Market Fees. <u>Regulation Services</u>: Ms Guzeleva indicated that the Review Outcome was to roll out the WEM Deviation Method to allocate costs for Regulation Raise and Regulation Lower, by October 2025. Ms Guzeleva clarified the explanation in the draft Information Paper of the straight line targets against which deviations will be measured as follows: • for Scheduled Facilities and Semi-Scheduled Facilities that provide Essential System Services (ESS) the paper indicates that the line will be from the Facilities' previous Dispatch Target to their current Dispatch Target but, instead, this should be from the Facilities' actual four-second SCADA measurement at the start of the Dispatch Interval; and • for Non-Dispatchable Loads, it will be a straight line between the implied four-second SCADA metering measurements at the start of the Dispatch Interval and the overall Dispatch Forecast less the SCADA measurement for Non-Dispatchable Leads on SCADA. • Mr Shubert noted that the paper indicates that a calculated metering value will be derived for residual Non-Dispatchable Loads (those without SCADA metering), by deducting the SCADA values for Non-Dispatchable Loads with SCADA metering from the sum of all Energy Producing Systems' injection over 4 seconds. Mr Schubert asked if this means that the residual Non-Dispatchable Loads will bear the impact of line losses. Ms Guzeleva indicated that the WEM Deviation Method does not allocate costs on the basis of actual consumption or generation, but on deviations from the line, so line losses should not make a difference. Mr Draper agreed, and noted that line losses are relatively constant over a five-minute Dispatch Interval, so they would not significantly impact calculation of the deviations. • Mr Schubert agreed. • Mrs Papps indicated that Alinta has no major concerns with the WEM Deviation Method, but noted that the paper	

Item	Subject	Action

indicates that the method is simple to implement and can be implemented at moderate cost.

- Mrs Papps expressed concern with the large number of changes being made through the WEM reform program and suggested that a committee is needed to provide oversight of priorities and consider workloads, similar to the Reform Delivery Committee used in the National Energy Market (NEM).

The Chair asked Ms Guzeleva to consider this suggestion, including whether the MAC could fill this role.

Ms Guzeleva noted that the WEM Deviation Method would not be implemented until October 2025 to avoid conflict with the new market start and to coincide with commencement of five-minute settlement.

Mr Draper agreed that there is a natural interdependency between the WEM Deviation Method and five-minute settlement.

Ms Guzeleva indicated that AEMO operates the existing cost allocation method for Load Following Ancillary Services (LFAS) in the NEM using a spreadsheet outside of its systems and that a similar, simple and low cost approach could be used for the WEM Deviation Method.

Ms Guzeleva indicated that there would be negative impacts on the amount of Regulation services and the cost of those services if this method is not implemented in 2025.

- Mrs Papps indicated that her concern is broader than just the WEM Deviation Method.

The Chair asked EPWA to further consider the timing and interdependencies of the various market reforms and whether there should be a roadmap.

- Mr Alexander noted the likely efficiency gains from the WEM Deviation Method and that this will benefit consumers, not just add costs, but also expressed concerns with workloads from the reform program.

The Chair suggested that possibly the MAC could play a role in advising EPWA on prioritising the pieces of the reform program.

- Mr Edwards noted that the WEM is moving closer to real-time dispatch, which is difficult from an engineering perspective, and expressed concern that the proposed cost allocation method relies on four-second SCADA data before we have experience in operating such a market.
- Mr Edwards suggested that using a four-second signal to incentivise behaviour may result in Market Participants overshooting their target, which could increase instability. Mr Edwards asked now this risk would be managed.

Ms Guzeleva indicated that this risk will be addressed by:

Item	Subject	Action
	• use of primary frequency response, noting that WEM Deviation Method will remove primary frequency response from the calculation of deviations; and • the WEM deviation method also removing any Regulation Raise and Lower service response from the calculations. Mr Draper noted that the new NEM method to allocate Regulation service costs is much more complex – it penalises those that contribute to deviations and rewards those that reduce deviations, and this is on top of primary frequency response. Mr Draper indicated that the simpler approach proposed for the WEM is partly to avoid problems like what Mr Edwards has raised. Ms Guzeleva indicated that AEMO will have two years of experience in operating the new market arrangements before the WEM Deviation Method is implemented, so the method could be tweaked based on any learning from the market. • Mr Price agreed with Mr Draper that the intent is to have a simpler economic driver to manage deviations, and that this would sit subordinate to AGC and regulation services. The idea is to have different frameworks to incentivise the volatility of load, and to get generation to more closely match forecasts and be less volatile. • Mr Price noted that the Information Paper lays out the high-level principles for the WEM Deviation Method and speaks to AEMO managing in accordance with those principles, such as by backing out primary frequency response. Mr Price asked if the paper could be clear that this will be specified in the WEM Rules. Ms Guzeleva indicated that EPWA would work with AEMO on drafting the Amending Rules and will publicly consult on the drafting. The details will likely be in an appendix, similar to the appendix that lays out the Runway Method (Appendix 2A). Ms Guzeleva indicated that AEMO would make default forecasts for Semi-Scheduled and Non-Scheduled Facilities but that Market Participants will have a choice to provide their own forecasts, and AEMO will need to make a judgement on which forecast to use in its scheduling and despatch process. The MAC did not make any further comments or raise any other concerns regarding the Review Outcomes for allocating the cost of Regulation services. <u>Contingency Reserve Raise (CRR) Services</u>: Ms Guzeleva indicated that the issue for CRR is an edge case that is currently not addressed in the WEM Rules and that there are some generators comprised of several units or inverters that have separate network connections. The current cost allocation method would consider these units to be a single facility under the	

Item	Subject	Action
	Runway Method in Appendix 2A, which is not fair if the facility can dispatch the separate units independently. Ms Guzeleva indicated that there will be a WEM Procedure for AEMO to allocate facility risk on the basis of an assessment of the largest contingency for the facility in terms of its share in the CRR costs. In response to a question from Mr Arias, Ms Guzeleva clarified that this issue is not about setting the level of the CRR requirement, but about allocating the cost for managing the risk. • Mr Arias suggested that the argument used to not make changes to the allocation of Market Fees could also apply for CRR, in that the change may address some inefficiencies but may not result in benefits for users. Mr Guzeleva indicated that the changes would have a clear benefit in aligning the method better with the causer-pays principle. Mr Draper pointed out that this amendment may also incentivise a different setup for inverters and network connections that may have efficiency benefits. The MAC did not make any further comments or raise any other concerns regarding the Review Outcomes for CRR services. <u>Contingency Reserve Lower (CRL) Services</u>: Ms Guzeleva indicated that one participant had raised concerns with the proposed allocation of CRL costs and that additional option analysis was undertaken to address this concerns. Ms Guzeleva noted that larger loads are likely to connect to the system in the future, which would increase the CRL requirement, and that the current method for allocating CRL costs would not allocate the costs to the causers of this increase. The decision is to use a Runway Method to allocate CRL costs, similar to the method to allocate CRR costs, which will encourage participants to connect to the system in a way that does not rapidly increase the CRL requirement. The MAC did not make any comments or raise any concerns regarding the Review Outcomes for CRL services. <u>Other ESS</u>: Ms Guzeleva outlined the Review Outcomes from the draft Information Paper. • Mr Maticka indicated that the learnings from Project Symphony will soon be available and may suggest that the allocation of some ESS costs may need to be tweaked. <u>Summary Discussion</u>: The Chair sought views from the MAC members that had not yet commented:	

Item	Subject	Action
	• Mr McKinnon indicated that Western Power is happy with the Review Outcomes, but that the WEM Deviation Method may not be as simple as suggested. • Mr Draper pointed out that the conclusion is only that it is simpler than that method that is being implemented in the NEM. • Mr Peake indicated that his only concern is that it will be hard for retailers to estimate some of these costs to allow them to offer 2-3 year contracts. • Ms Teo, Mr Huxtable and Mr Stephen indicated that they had no comments. The Chair thanked the MAC members for their input, noted that the intent is to publish the Information Paper on 15 June 2023 and asked MAC members to provide any additional written comments to EPWA by 3:00 on 9 June 2023.	
	Action: MAC members are to provide EPWA with any further written comments on the draft Cost Allocation Review Information Paper.	**MAC Members (8 June 2023)**

9	**Scope of Works for the WEM Investment Certainty Review**
	The Chair noted that EPWA is seeking support from the MAC to commence the WEM Investment Certainty (WIC) Review and is seeking comments on the draft Scope of Works for the review.
	Ms Guzeleva summarised the background for the WIC Review and indicated that it will cover five initiatives:
	• Initiative 1 is a review of the Reserve Capacity Price (RCP). Ms Guzeleva noted that:
	    • there was a great deal of comment about the RCP during the RCM Review, even though the RCP was recently reviewed in 2018;
	    • the WEM has changed substantially since the last RCP Review, when there was significant overcapacity on the system;
	    • the WEM needs new technologies to enter the market, some of which have different requirements for financing; and
	    • it is not a foregone conclusion that the RCP needs to be changed, assessing the need for change will be part of the review.
	• Initiative 2 is a 10-year RCP guarantee for new technologies. Ms Guzeleva noted that there was a strong push in the RCM Review to extend the current five-year RCM guarantee to 10 or 15 years, especially for new technologies.	

- Initiative 3 is an energy revenue guarantee for renewable generators that firm up their capacity. Ms Guzeleva noted that:
  - the financial modelling in Chapter 6 of the *RCM Review Information Paper (Stage 1) and Consultation Paper (Stage 2)* suggests that:
    - ESR and other technologies will likely be able to continue to make profit; but
    - energy prices will collapse at some point in the 2030s when baseload fossil fueled plant exits the market, and wind and solar generation may not earn sufficient revenue once the LGCs cease;
  - the proposal is to:
    - investigate ways to provide additional energy market revenue, outside of the market dispatch mechanism, to support renewable generators, potentially as a top-up to the level that prices were at before the expected price collapse; and
    - in return for the top-up, require the facilities to demonstrate through the certification process that they have firmed up their capacity.
- Initiative 4 is to finalise the design of the emission thresholds arrangements that were discussed by the MAC and RCMRWG under the RCM Review.
- Initiative 5 is to provide a 10-year exemption from the emissions thresholds for facilities that qualify to provide flexible capacity.

Ms Guzeleva noted that the Minister announced these initiatives on 9 May 2023 and they need to be developed through industry consultation, and that the emissions thresholds is an approved Government policy.

The Chair sought comments from the MAC members:

- Mr Maticka supported the WIC Review and agreed that it is important to fully understand the barriers to investment in new renewable facilities, but suggested that the first step should be to identify the potential barriers to investment and to determine whether the announced initiatives will address those barriers.
- Mr Peake noted that financiers generally do not account for opportunistic ‘bonus’ revenue when considering whether to finance a project, such as potentially higher RCP if capacity is short, but that they tend to account for the potential loss of revenue if the RCP were to fall.
- Mr Peake commented that irrational Government decisions are also a major risk to financing projects.

Item	Subject	Action

	• Mrs Papps supported the WIC Review but suggested that the WIC Review should also consider whether:
	  • any other reforms are needed, such as up-front capital contributions; and
	  • any of the proposed reforms may have perverse incentives, particularly the wholesale energy revenue guarantee.
	• Mrs Papps suggested that the review should first consider initiatives 2, 4 and 5, which are easier to consider, and separate these from initiative 1 and 3, which are more controversial.
	Ms Guzeleva agreed that sequencing is important and sought views from the MAC.
	• Mr Peake sought clarity on what 'new technology' means for Initiative 2 – would it include established technology that is new to the WEM, such as pumped hydro storage, or is it only new technologies, like biofuels.
	Ms Guzeleva indicated that the definition of 'new technology' is to be considered as part of the review and will need to be addressed early in the review.
	• Mr Schubert supported the WIC Review and suggested that the large number of changes that are occurring in the market are barriers to investment.
	Ms Guzeleva indicated that initiatives would likely be implemented at different times, and in particular, that the energy revenue top-up would be implement sometime in the future, but should help provide certainty early.
	Ms Guzeleva noted that the energy industry is undergoing a major transition which cannot be achieved without changes.
	• Mr Schubert sighted the renewable hydrogen target and the emissions thresholds scheme as example of unexpected reforms that create uncertainty.
	• Mr Alexander indicated that the review seems to focus on utility scale resources and not on what can be done to support investment in distributed energy. Ms Guzeleva agreed.
	• Mr Huxtable supported the WIC Review and suggested that it is good to have a structured approach instead of considering ideas from left field.
	• Mr Stephen supported the WIC Review and suggested that the review should incorporate any other ideas identified during the review because, while the plan is currently to complete the review within one year, it will likely take longer.
	• Ms Teo and Mr Arias agreed with Mr Stephen.	

Item	Subject	Action
	• Mr McKinnon and Mr Edwards supported the review. Ms Guzeleva did not support widening the scope of the WIC Review because it was already too complex. In response to a question from Mr Price, Ms Guzeleva pointed out that the WIC Review is not intended to review the fundamentals of the WEM established by the Energy Reform Taskforce and other recent reviews. The objective of the WIC is to address the issue of potential revenue shortfall and implement the emissions thresholds that have been identified/discussed in the RCM Review but could not be addressed. The Chair summarised the MAC's comments that the WIC Review should: • be cognisant of workloads to develop and implement reforms; and • be cognisant of the impact of government intervention on investment. Ms Guzeleva indicated that the WIC Review was not intended to recommend direct cash injections.	
10	**Scope of Works for the MAC Review** The Chair noted that MAC members were being asked to provide support for the commencement of a review of the MAC and the process and the operation of the MAC; and asked the MAC to provide any comments. The Chair noted that Mrs Papps had raised concern with the timing of the review and asked whether the MAC should have a role in the sequencing and prioritisation of the work underway. Ms Guzeleva noted that she believes that much has been achieved in bringing balance to the MAC. She added that the MAC has been run in a more efficient and effective way since early 2022 when the MAC secretariat was transferred to EPWA, the independent Chair came on board and the two consumer representatives were appointed. Ms Guzeleva indicated that the point of the MAC Review was to check whether anything could be done better in terms of the balance of views. Ms Guzeleva expressed concern that the balance was not always achieved, but the intent of the review was not necessarily to implement substantial change, rather to check that the MAC operates in the best way possible. Ms Guzeleva noted the review was not intended to take long, be time consuming or take a lot of resources. • Mr Alexander indicated that the MAC's governance needs to work as well as possible given the amount of work that is to be done over the next few years, and that the approach that was outlined in the Scope of Work (SOW) seemed very sensible.	

Item	Subject	Action
	• Mr Arias and Mr Stephen noted concerns with the timing of the review, and not with a review of MAC governance, as the proposed schedule had much of the work and consultation in August through October, which coincided with a period of significant market reform implementation. The Chair asked Ms Guzeleva if there was opportunity to delay the timing of the review. Ms Guzeleva noted that, while she did not consider it to be an urgent review, it would require less effort compared to other reviews. The review could be postponed to 2024. Ms Guzeleva considered that the MAC should be interested in providing the most effective and efficient advice to the Coordinator. • Mr McKinnon noted that Western Power supports the review and asked if Western Power could have two representatives, regulatory and operational, noting that the WEM was now far more encompassing. Mr McKinnon noted Western Power's preference to start the review earlier rather than later. The Chair noted that representation on the MAC was covered in the Scope of Works for the review. • Mr Edwards supported the review and noted with regard to timing that, if any of the outcomes were likely to change the information on which investment decisions are made, then the review should be undertaken as soon as possible. The Chair noted that Mr Edwards believed that such a review could improve the governance of the MAC and therefore potentially affect investment. • Mrs Papps supported the comments made by Mr Arias and Mr Stephen. • Mr Maticka noted the workload concerns, but noted that he was neutral regarding the timing of the review. • Ms Teo and Mr Huxtable supported the review and the SOW, but shared the other members' concerns regarding the timing. • Mr Peake supported the review and suggested that it could be undertaken independently rather than by EPWA. Ms Guzeleva indicated that EPWA would take on board comments relating to the timing of the review. In response to Mr Peak's suggestion for an independent review, Ms Guzeleva noted that, regardless of the review timing, she would like to hear from MAC members if they have any concerns with EPWA's administration of the MAC or if any improvements can be made. The Chair noted that there was general support for the MAC Review and that consideration would be given as to the timing of the review.	

Item	Subject	Action
	Action: EPWA to consider the timing of the MAC review.	**EPWA**
11	**General Business** Ms Guzeleva noted that EPWA published a Consultation Paper on Stage 2 of the Supplementary Reserve Capacity Review and invited MAC members to make submissions. The Chair indicated that the value of face-to-face MAC meetings would be discussed at the next MAC meeting and asked Mr Maticka to share any of AEMO’s learnings from the solar eclipse. • Mr Maticka noted that an extreme amount of preparation went into the eclipse to ensure everything ran smoothly and that it was a clear day, so the plan went as expected. The next MAC meeting is scheduled for 20 July 2023.	

The meeting closed at 11:30am.

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

Agenda Item 4: MAC Action Items

Market Advisory Committee (**MAC**) Meeting 2023_07_20

Shaded	Shaded action items are actions that have been completed since the last MAC meeting. Updates from last MAC meeting provided for information in RED.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
9/2023	MAC Secretariat to publish the minutes of the 20 April 2023 MAC meeting on the Coordinator's Website as final.	MAC Secretariat	2023_06_08	**Closed** The minutes were published on the Coordinator's Website on 8 June 2023.
10/2023	MAC members are to provide EPWA with any further written comments on the draft Cost Allocation Review Information Paper.	MAC members	2023_06_08	**Closed** EPWA received no further comments.
11/2023	EPWA to consider the timing of the MAC review.	EPWA	2023_06_08	**Closed** The MAC Review will commence in 2024.

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

Agenda Item 5: Market Development Forward Work Program

Market Advisory Committee (**MAC**) Meeting 2023_07_20

1. Purpose

- To provide an update on the Market Development Forward Work Program.
- Changes to the Market Development Forward Work Program provided at the previous MAC meeting are shown in red font in the Tables below.

2. Recommendation

- The MAC Secretariat recommends that the MAC notes the updates to the Market Development Forward Work Program provided in Tables 1-4, including that:
  - the Chair of the Reserve Capacity Mechanism Review Working Group (RCMRWG) is to update the MAC on the progress of the Reserve Capacity Mechanism (RCM) Review– see Agenda Item 6(b);
  - EPWA is to update the MAC on the progress of the Supplementary Reserve Capacity (SRC) Review – see Agenda Item 9; and
  - the Chair of the Demand Side Response Review Working Group (DSRRWG) is to update the MAC on the progress of the Demand Side Response (DSR) Review – see Agenda Item 6(c); and

3. Process

Stakeholders may raise issues for consideration by the MAC at any time by sending an email to the MAC Secretariat at energymarkets@dmirs.wa.gov.au.

Stakeholders should submit issues for consideration by the MAC two weeks before a MAC meeting so that the MAC Secretariat can include the issue in the papers for the MAC meeting, which are circulated one week before the meeting.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
RCM Review	A review of the RCM, including a review of the Planning Criterion.	• The MAC has established the RCM Review Working Group (**RCMRWG**). Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group, including: o the Terms of RCMRWG, as approved by the MAC; o the list of RCMRWG members; o meeting papers and minutes from the RCMRWG meeting on 20 January 2022, 17 February 2022, 17 March 2022, 5 May 2022, 2 June 2022, 16 June 2022, 14 July 2022, 2 July 2022, 13 October 2022, 24 November 2022; 15 December 2022, 1 February 2023, 16 February 2023, 2 March 2023 and 22 March 2023; and o meeting papers for the RCMRWG meeting on 6 July 2023. • The following papers have been released and are available on the RCM Review webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review: o the Scope of Works for the review, as approved by the Coordinator; o the Stage 1 Consultation Paper; o the Paper on the Review of International Capacity Mechanisms; o submissions on the Stage 1 Consultation Paper; o the RCM Review Information Paper (Stage 1) and Consultation Paper (Stage 2); and o submissions on the RCM Review Consultation Paper (Stage 2).

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Cost Allocation Review	A review of: • the allocation of Market Fees, including behind the meter (**BTM**) and Distributed Energy Resources (**DER**) issues; • cost allocation for Essential System Services; and • Issues 2, 16, 23 and 35 from the MAC Issues List (see Table 3).	• The MAC has established the Cost Allocation Review Working Group (**CARWG**). Information on the CARWG is available at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group, including: o the Scope of Work for the review, as approved by the Coordinator; o the Terms of Reference for the CARWG, as approved by the MAC; o the list of CARWG members; o the Consultation Paper; o the International Review; o submissions on the Consultation Paper; o meeting papers and minutes from the CARWG meetings on 9 May 2022, 7 June 2022, 30 August 2022, 27 September 2022, 25 October 2022, 29 November 2022, and 21 March 2023 and 2 May 2023; and o the Cost Allocation Review Information Paper. • EPWA plans to publish an Exposure Draft of the proposed WEM Amending Rules to implement the Review Outcomes for consultation in August 2023.
Procedure Change Process Review	A review of the Procedure Change Process to address issues identified through Energy Policy WA's consultation on governance changes.	• The MAC discussed a draft Scope of Work for this review at its meeting on 11 October 2022. MAC members provided comments on the draft Scope of Works at that meeting, and were asked to provide further comments by email. EPWA did not receive any further comments. • EPWA will update the Scope of Works to reflect the MAC discussions and, following the Coordinator approval of the Scope, will provide the final scope and a timeline for the review to the MAC in early 2023.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Forecast quality	Review of Issue 9 from the MAC Issues List (see Table 4).	• This review has been deferred.
Network Access Quantity (**NAQ**) Review	Assess the performance of the NAQ regime, including policy related to replacement capacity, and address issues identified during implementation of the Energy Transformation Strategy (ETS).	• This review will be commenced after completion of the RCM Review.
Short Term Energy Market (**STEM**) Review	Review the performance of the STEM to address issues identified during implementation of the ETS.	• This review has been deferred.
Review of the Participation of Demand Side in the Wholesale Electricity Market (**WEM**)	The scope of this review is to: • identify the different ways that Loads/Demand Side Response can participate across the different WEM components; • identify and remove any disincentives or barriers for Loads/Demand Side Response participating across the different WEM components; and • identify any potential for over- or under-compensation of Loads/Demand Side Response (including as part of 'hybrid' facilities") as a result of their participation in the various market mechanisms.	• The MAC endorsed a Scope of Work for this review at its meeting on 16 March 2023. • The MAC has established the Demand Side Response Review Working Group (DSRRWG). Information on the DSRRWG is available at Demand Side Response Review Working Group (www.wa.gov.au), including: o the Scope of Work for the review, as approved by the Coordinator; o the Terms of Reference for the DSRRWG, as approved by the MAC; o meeting papers and minutes from the DSRRWG meeting on 10 May 2023; and o meeting papers from the DSRRWG meeting on 7 June 2023.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
WEM Investment Certainty (**WIC**) Review	The WIC Review will consider, design and implement the following five reforms that have been announced by the Minister for Energy, which are aimed at providing further investment certainty to assist the decarbonisation of the WEM: (1) changing the Reserve Capacity Price (RCP) curve so it sends sharper signals for investment when demand for new capacity is stronger; (2) a 10-year RCP guarantee for new technologies, such as long-duration storage; (3) a wholesale energy price guarantee for renewable generators, to top up their energy revenues as WEM prices start to decline, in return for them firming up their capacity; (4) emission thresholds for existing and new high emission technologies in the WEM; and (5) a 10-year exemption from the emissions thresholds for existing flexible gas plants that qualify to provide the new flexibility service.	• The MAC supported a Scope of Work for this review at its meeting on 8 June 2023. Information on the WIC Review is available at https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-investment-certainty-review, including: o the final Scope of Work for the review addressing MAC's comments, as approved by the Coordinator. • Under Agenda Item 8 MAC members are being asked to approve: o the establishment of a Working Group to assist with the WIC Review; and o the Terms of Reference for the WIC Review Working Group.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Review of the Market Advisory Committee (**MAC**)	The scope of this review is to ensure that the purpose, representation, process and operations of the MAC are fit for purpose, and in particular, that it operates efficiently and provides balanced, timely and useful advice to the Coordinator.	• The MAC supported a Scope of Works for this review at its meeting on 8 June 2023, and advised EPWA to further consider the timing of the review. • In response to MAC's comments, EPWA now proposes to commence the MAC Review in early 2024.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
1	Shane Cremin November 2017	**IRCR calculations and capacity allocation** There is a need to look at how IRCR and the annual capacity requirement are calculated (i.e. not just the peak intervals in summer) along with recognising BTM solar plus storage. The incentive should be for retailers (or third-party providers) to reduce their dependence on grid supply during peak intervals, which will also better reflect the requirement for conventional 'reserve capacity' and reduce the cost per kWh to consumers of that conventional 'reserve capacity'.	To be considered in the RCM Review.
3	Shane Cremin November 2017	Penalties for outages.	To be considered in the RCM Review.
4	Shane Cremin November 2017	Incentives for maintaining appropriate generation mix.	To be considered in the RCM Review.
14/36	Bluewaters and ERM Power November 2017	**Capacity Refund Arrangements:** The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund exposure is more than what is necessary to incentivise the Market Participants to meet their obligations for making capacity available. Practical impacts of such excessive refund exposure include: • compromising the business viability of some capacity providers – the resulting business interruption can compromise reliability and security of the power system in the SWIS; and • excessive insurance premiums and cost for meeting prudential support requirements.	To be considered in the RCM Review.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
		Bluewaters recommended imposing seasonal, monthly and/or daily caps on the capacity refund. Bluewaters considered that reviewing capacity refund arrangements and reducing the excessive refund exposure is likely to promote the Wholesale Market Objectives by minimising: • unnecessary business interruption to capacity providers and in turn minimising disruption to supply availability; which is expected to promote power system reliability and security; and • unnecessary excessive insurance premium and prudential support costs, the saving of which can be passed on to consumers.	
30	Synergy November 2017	**Reserve Capacity Mechanism** Synergy would like to propose a review of WEM Rules related to reserve capacity requirements and reserve capacity capability criteria to ensure alignment and consistency in determination of certain criteria. For instance: • assessment of reserve capacity requirement criteria, reserve capacity capability and reserve capacity obligations; • IRCR assessment; • Relevant Demand determination; • determination of NTDL status; • Relevant Level determination; and • assessment of thermal generation capacity. The review will support Wholesale Market Objectives (a) and (d).	To be considered in the RCM Review.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
56	Perth Energy July 2019	**Issues with Reserve Capacity Testing** • Market Generators that fail a Reserve Capacity Test may prefer to accept a small shortfall in a test (and a corresponding reduction in their Capacity Credits) than to run a second test. • There is a discrepancy between the number of Trading Intervals for self-testing vs. AEMO testing. • There is ambiguity in the timing requirements for a second test when the relevant generator is on an outage. • There is ambiguity on the number of Capacity Credits that AEMO is to assign when certain test results occur.	To be considered in the RCM Review (except that the first bullet may be out scope, in which case it will be added to Table 4).
58	MAC October 2019	**Outage scheduling for dual-fuel Scheduled Generators** '0 MW' outages are currently used to notify System Management when a dual-fuel Scheduled Generator is unable to operate on one of its nominated fuels. There is no explicit obligation in the WEM Rules or the Power System Operation Procedure: Facility Outages to request/report outages that limit the ability of a Scheduled Generator to operate using one of its fuels. In terms of the provision of sent out energy (the service used to determine Capacity Cost Refunds), it is questionable whether this situation qualifies as an outage at all. More generally, the WEM Rules lack clarity on the nature and extent of a Market Generator's obligations to ensure that its Facility can operate on the fuel used for its certification, what (if anything) should occur if these obligations are not met, and the implications for outage scheduling and Reserve Capacity Testing. • (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	To be considered in the RCM Review (or may be out of scope, in which case it will be added to Table 4).

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
2	Shane Cremin November 2017	Allocation of market costs – who bears Market Fees and who pays for grid support services with less grid generation and consumption?	Closed – Considered in the Cost Allocation Review. Refer to the Cost Allocation Review Information Paper. EPWA plans to publish for consultation an Exposure Draft of the proposed WEM Amending Rules to implement the Review Outcomes.
16	Bluewaters November 2017	BTM generation is treated as reduction in electricity demand rather than actual generation. Hence, the BTM generators are not paying their fair share of the network costs, Market Fees and ancillary services charges. Therefore, the non-BTM Market Participants are subsiding the BTM generation in the WEM. Subsidy does not promote efficient economic outcome. Rapid growth of BTM generation will only exacerbate this inefficiency if not promptly addressed. Bluewaters recommends changes to the WEM Rules to require BTM generators to pay their fair share of the network costs, Market Fees and ancillary services charges. This is an example of a regulatory arrangement becoming obsolete due to the emergence of new technologies. Regulatory design needs to keep up with changes in the industry landscape (including technological change) to ensure that the WEM continues to meet its objectives. If this BTM issue is not promptly addressed, there will be distortion in investment signals, which will lead to an inappropriate generation facility mix in the WEM, hence compromising power system security and in turn not promoting the Wholesale Market Objectives.	Closed – Considered in the Cost Allocation Review. Refer to the Cost Allocation Review Information Paper.

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
23	Bluewaters November 2017	Allocation of Market Fees on a 50/50 basis between generators and retailers may be overly simplistic and not consider the impacts on economic efficiency. In particular, the costs associated with an electricity market reform program should be recovered from entities based on the benefit they receive from the reform. This is expected to increase the visibility of (and therefore incentivise) prudence and accountability when it comes to deciding the need and scope of the reform. Recommendations: to review the Market Fees structure including the cost recovery mechanism for a reform program. The cost saving from improved economic efficiency can be passed on to the end consumers, hence promoting the Wholesale Market Objectives.	Closed – Considered in the Cost Allocation Review. Refer to the Cost Allocation Review Information Paper.
35	ERM Power November 2017	**BTM generation and apportionment of Market Fees, ancillary services, etc.** The amount of solar PV generation on the system is increasing every year, to the point where solar PV generation is the single biggest unit of generation on the SWIS. This category of generation has a significant impact on the system and we have seen this in terms of the daytime trough that is observed on the SWIS when the sun is shining. The issue is that generators that are on are moving around to meet the needs of this generation facility but this generation facility, which could impact system stability, does not pay its fair share of the costs of maintaining the system in a stable manner. That is, they are not the generators that receive its fair apportionment of Market Fees and pay any ancillary service costs but yet they have absolute freedom to generate into the SWIS when the fuel source is.	Closed – Considered in the Cost Allocation Review. Refer to the Cost Allocation Review Information Paper.

Table 4 – Other Issues			
Id	**Submitter/Date**	**Issue**	**Status**
9	Community Electricity November 2017	Improvement of AEMO forecasts of System Load; real-time and day-ahead.	Consideration of this issue has been deferred.

MARKET ADVISORY COMMITTEE MEETING, 20 July 2023

FOR DISCUSSION

SUBJECT: UPDATE ON AEMO'S WEM PROCEDURES

AGENDA ITEM: 6(A)

1. PURPOSE

Provide a status update on the activities of the AEMO Procedure Change Working Group and AEMO Procedure Change Proposals.

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meetings	**Next meeting**
Date	14 June 2023	As required
WEM Procedures for discussion	WEM Procedure: Supplementary Reserve Capacity WEM Procedure: Reserve Capacity Security	

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 20 July 2023. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported or a decision has been taken not to proceed with a potential Procedure Change Proposal.

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2023_01 WEM Procedure: Supplementary Capacity [previously titled WEM Procedure: Supplementary Reserve Capacity]	In response to the Amending Rules, gazetted on 28 April 2023, the replacement Procedure, which commenced on 1 July 2023: • clarifies the role of Western Power in supporting a call for expressions of interest and the procurement of supplementary capacity services by AEMO; • specifies timelines for the provision of information and assistance to support the call for expressions of interest and procurement of supplementary capacity services; • clarifies information requirements for applicants who request assistance or an assessment by Western Power; and • reinforces alignment to the WEM Rules, as amended. AEMO has also taken the opportunity to: • move the Procedure to AEMO's new WEM Procedure template; and • make editorial and typographical changes.	Commenced	N/A	N/A

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2023_02 WEM Procedure: Reserve Capacity Security	AEMO has proposed two separate revisions of the Reserve Capacity Security WEM Procedure to commence 31 July 2023 and 1 October 2023 respectively: Amendments proposed to commence 31 July 2023 include: • updates to the Security Deposit deeds, bank guarantees and bank undertakings requirements to allow Market Participants to submit electronic copies (Originals must still be provided within 20 business days); • migration to AEMO's new WEM Procedure template; and • other minor administrative changes. Amendments proposed to commence 1 October 2023 include: changes to the Required Level calculations to account for Separately Certified Components from the 2023-24 Capacity Year in accordance with the Wholesale Electricity Amendment (Tranche 5 Amendments) Rules.	Consultation Closed	Publication of the first set of proposed amendments	31 July 2023

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2022_02 WEM Procedure: DER Register Information Procedure	AEMO proposed amendments to the Procedure to: • incorporate electric vehicles (EVs) and electric vehicle charging equipment data; • integrate changes following amendments to the Australian Standard AS/NZS 4777.2:2015 which has been superseded by AS/NZS 4777.2:2020; • implement minor changes that better reflect the changed operational expectations of DER in the WEM and SWIS (e.g. implementation of Emergency Solar Management); • improve the completeness and quality of data exchanged between Network Operators and AEMO (e.g. conveying additional context to reinforce clarity in the document; better aligning the Procedure with related technical specifications); and • reinforce alignment to the WEM Rules, and make other minor administrative changes.	Consultation Closed	Procedure Commencement	02/10/2023

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

Agenda Item 6(b): Update on the RCM Review Working Group

Market Advisory Committee (MAC) Meeting 2023_07_20

1. Purpose

- The Chair of the Reserve Capacity Review Working Group (RCMRWG) to provide an update on the activities of the RCMRWG since the last MAC meeting.

2. Recommendation

That the MAC notes:

(1) the submission window for part 2 of the RCM Review: Information Paper (Stage 1) and Consultation Paper (Stage 2) closed on 6 June 2023 and 16 submissions were received;

(2) the update from the RCMRWG meetings on 6 and 13 July 2023; and

(3) that the outcomes of the RCMRWG and MAC meetings to date are reflected in the draft Reserve Capacity Mechanism – Stage 2 Information Paper that is tabled for discussion under Agenda Item 10.

3. Process

- The MAC discussed the draft RCM Review Information and Consultation Paper (Paper) at its meeting 20 April 2023.
  - o the Paper was published with the title RCM Review: Information Paper (Stage 1) and Consultation Paper (Stage 2) on 3 May 2023;
  - o the submission window for part 2 of the Paper closed on 5 June 2023 (extended from 31 May 2023); and
  - o EPWA received 16 Submissions. Issues raised in the submissions and EPWA's responses are included in the draft Reserve Capacity Mechanism – Stage 2 Information Paper that is tabled for discussion under Agenda Item 10.
- On 6 July 2023 the RCMRWG discussed amendments to the proposals in the Paper to address issues raised in submissions and one additional proposal:
  - o additional proposal to remove the mandatory nature of the Expression of Interest Process for participation in the RCM;
  - o amendments to the obligations for Electrical Storage Resources providing flexible capacity
  - o alternative options for the determination of the Flexible IRCR to limit gaming potential;
  - o amendments to the refund regime to allow for different refund pools for peak capacity and flexible capacity;
  - o amendments to the certification of Demand Side Programmes;

  - options for reducing the number of hours that Demand Side Programmes can be dispatched during one Capacity Year; and
  - amendments to the proposed refund regime for Demand Side Programmes.
- On 13 July 2023 the RCMRWG discussed issue raised relating to proposal S in the Paper. (Proposal S: Distribute collected capacity refunds to consuming participants rather than other capacity providers.)
- The outcomes of the 6 and 13 July RCMRWG meetings area reflected in the draft Reserve Capacity Mechanism – Stage 2 Information Paper.
- Papers and minutes for the RCMRWG meetings are available on the RCMRWG webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group.
- Further information on the RCM Review, including the Paper and submissions are available on the RCM Review webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review.

4. Next Steps

- Publish the RCM Review: Information Paper (Stage 2).
- Publish exposure draft to implement the RCM Review decisions.

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

Agenda Item 6(c): Update on the Demand Side Response Review Working Group

Market Advisory Committee (MAC) Meeting 2023_07_20

1. Purpose

The Chair of the Demand Side Response Review Working Group (DSRRWG) is to provide an update on the activities of the DSRRWG since the last MAC meeting.

2. Recommendation

That the MAC notes:

- the minutes from the DSRRWG meeting on 7 June 2023 (Attachment 1); and
- the update from the DSRRWG meeting on 5 July 2023

Background

- The second DSRRWG meeting was held on 7 June 2023 and the following key items were discussed:
  - o Hybrid Facilities – consideration of the treatment of, and revenue pathways available to, Hybrid Facilities containing loads, including identifying any initial barriers and considerations.
  - o Curtailable access for loads – consideration of whether there should be an equivalent of the constrained access regime for the supply side implemented for the demand side.
- The third DSRRWG meeting was held on 5 July 2023 and the following key items were discussed:
  - o Constrained load access – consideration of the future role of runback schemes, and the required level of transparency and their integration in various market components.
  - o Hybrid Facilities – consideration of different potential configurations for hybrid facilities containing loads to determine whether each scenario is, or should be, allowed in the WEM and if so, how barriers to those configurations can be removed where appropriate.
  - o Minimum demand support – consideration of how minimum operational demand can be avoided, and alternative responses to ensure system stability.
  - o DSP obligations – consideration of how to design an efficient dynamic baseline.
- Additional information on the DSRRWG, including meeting papers, is available on DSRRWG website at: [Demand Side Response Review Working Group (www.wa.gov.au)](www.wa.gov.au).

3. Next Steps

- The fourth DSRRWG meeting is scheduled for 2 August 2023. An agenda for that meeting is yet to be finalised but is expected to include discussion on the following points:
  - Real-Time Market participation;
  - Essential System Services participation; and
  - the role of DSR in the Short Term Energy Market.

4. Attachments

(1) Minutes of DSRRWG 7 June 2023

Minutes

Meeting Title:	Demand Side Response Review Working Group (DSRRWG)
Date:	7 June 2023
Time:	9:33 AM to 11:31 AM
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	(Chair) EPWA	
Dimitri Lorenzo	Bluewaters Power	
Tessa Liddelow	Shell Energy	
Jake Flynn	Collgar Wind Farm	
Thomas Higgins	Perth Energy	
Valentina Kogon	Western Power	
Graeme Ross	Simcoa Operations	
Peter Huxtable	Water Corporation	
Oscar Carlberg	Alinta Energy	
Toby Price	AEMO	
Tom Butler	AEMO	First meeting, replacing Toby Price in future meetings
Devika Bhatia	ERA	
Wayne Trumble	Newmont Mining	
Claire Richards	Enel X	
George Martin	Starling Energy	
Michael Zammit	Integrated Management Services	
Noel Schubert	Small-Use Consumer Representative	
Chris Alexander	Small-Use Consumer Representative	
Mitch O’Neill	Grids	First meeting
Erin Stone	Point Global	First meeting, observer for EPWA
Sarah Graham	EPWA	
Thomas Marcinkowski	EPWA	
Bobby Ditric	Consultant – Lantau Group	
Dave Carlson	Consultant – Lantau Group	

Mike Thomas	Consultant – Lantau Group	
Nicolas Taylor	Consultant – Lantau Group	
Apologies	**From**	**Comment**
Justin Ashley	Synergy	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:33 AM with Acknowledgement of Country.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above and invited new attendees to briefly introduce themselves.	
3	**Introductions** The Chair outlined the two broad issues for discussion by the working group at the meeting: • the operation of hybrid facilities in the market; and • whether there should be a regime for loads, similar to the network access quantity regime that applies to supply side resources under the Reserve Capacity Mechanism.	
4	**Hybrid Facilities discussion** The Chair invited Mr Ditric to introduce the discussion on the operation of hybrid facilities in the market. Mr Ditric highlighted the following key issues: o The concept of hybrid facilities is commonly thought of as storage and generation combination. However, the WEM Rules define a hybrid facility as any combination of two different technology types. This means that a load can be part of a hybrid facility. o A hybrid facility is considered a single facility for the purpose of operations under the WEM Rules, but Capacity Credits are assigned to each technology type. Therefore, capacity obligations must be met at the technology component level and, therefore, there are sub-metering obligations under the WEM Rules. o AEMO will determine a hybrid facility's level of controllability depending on the relative sizes of the technology types. • Mr Price highlighted that the sub-metering requirements being discussed only apply for scheduled and semi-scheduled facilities. Arrangements for non-scheduled facilities are different. Mr Ditric noted that sub-meters are not used for settlement, but are required for certifying capacity and for testing. • Mr Huxtable asked why, under the current rules, it was not possible to use high quality metering for dispatch and settlement, and whether this was due to the quality of metering data.	

Item	Subject	Action
	The Chair noted that the Metering Code, standard metering practices and national legislation require the meters used for settlement to be installed, owned and operated by Western Power The Chair added that the kind of sub-metering cannot be used for settlement under the applicable national legislation. The Chair highlighted the distinction between settlement of energy, which required revenue-grade meters, and the notional allocation of capacity credits under the RCM for which a lower level accuracy of metering is considered acceptable. • Mr Butler noted that this was consistent with arrangements for the DER aggregation trial, in which energy aggregation and settlement is being determined at the NMI connection point. The Chair noted that allowing hybrid facilities to install sub-meters at a quality lower than revenue grade metering was to reduce barriers to aggregation, but this was not appropriate to settle energy transactions in the WEM. Mr Ditric pointed participants to AEMO's sub-metering procedure for more information about different Facilities' metering requirements under the Reserve Capacity Mechanism (RCM). • Mr Huxtable asked whether Western Power's revenue-grade metering could be installed behind the NMI connection point (i.e. at a sub-component level). The Chair stated that Western Power metering could be installed at a sub-component level but this would need additional consideration and settlement calculations, and Western Power metering procedures would need to be changed. The Chair clarified that if there are two separate connections with two revenue-grade meters, the facility would not be a hybrid. However, if there were two Western Power meters associated with a single connection the calculations would need to be changed to remove double-counting with both meters being read. Mr Ditric added the following: o Each component of a hybrid facility is certified separately for each technology type with the total capped by the NAQ, except in the case of a hybrid non-scheduled facility. Assessment of an intermittent generator is as an individual facility under the relevant level methodology. o Aggregated DSPs are eligible for capacity credits as part of a hybrid facility. Under the new rules DSPs require all of their associated NMIs to have a common transmission network identifier (TNI). Mr Ditric posed the question whether an aggregated hybrid facility with a DSP is possible given the requirement for sub-metering and a common TNI. • Mr Price said that if a load can be reduced simultaneously with generation that can be increased, both components have a value to the system.	

Item	Subject	Action

	The Chair queried whether it would be helpful to the system for a load certified as a DSP alongside storage to be charged by that same storage to meet the load's DSP obligations.
	Mr Thomas said that it is not just the system benefit that must be considered, but also the linkage to the various market elements that provide revenue to compensate the facility.
	The working group agreed further work was required to consider:
	• the role of a hybrid facility with aggregated DSP, rather than a DSP consisting of a large load;
	• aggregating at a connection point;
	• how non-dispatchable loads in hybrid facilities with storage and/or a generator would work in practice;
	• how scheduled and semi-scheduled facilities containing a load component would operate and how the rules work regarding DSPs and IRCR avoided by hybrids.
	The Chair summarised four key scenarios available to a load to allow it to optimise operation and market efficiency, that the group should consider:
	• storage and load neither of which is certified, with the storage simply used to reduce IRCR.
	• storage is certified as a separate component but load is not, therefore it is necessary to ensure storage is available to the system (i.e. storage is not charging its load to reduce its IRCR).
	• the DSP is certified and the storage is not.
	• both the load and the storage are certified, in which case it is necessary to ensure the system actually benefits from both.
	Mr Ditric discussed the idea of value stacking for hybrids, noting the difference between value stacking and double dipping needs to be clearly defined. He highlighted the example where there is an ESR and load hybrid facility with the ESR only having capacity credits, and the facility reducing its consumption during peak intervals to reduce IRCR values. He asked if this scenario provides a net benefit to the system, or a misalignment between various obligations, incentives and payments.
	• Mr Schubert expressed the view that the answer to that question was determined by what such a hybrid is doing at the time of peak demands that drive the need for capacity and the allocation of capacity credits:
	    o If the ESR receives capacity credits then it should be available at peak times and it cannot also be used at that time for reducing IRCR consumption because that is double dipping.
	    o If, however, the facility reduces its demand from the system at other times (by the ESR supplying the local load) then that would not constitute double dipping.
	The Chair and Mr Huxtable agreed, and highlighted the importance of separate metering to measure the individual components' performance during peak times.	

Item	Subject	Action
	The Chair queried whether, if a load reduces its consumption for IRCR purposes and is properly metered, it would be able to obtain that value as a DSP in the following year. • Mr Huxtable confirmed it could not. The Chair posed some further questions regarding hybrid facilities: • How will a participant convince AEMO it is benefiting the system by both reducing the load and making storage available in storage obligation intervals; • How would compliance be monitored in that scenario; • does a participant pay refunds if sub-metering suggests it had offered storage in storage obligation intervals but charged the loads during those intervals. The Chair suggested the need for the WEM Rules to give participants a choice but make sure there was actually a benefit to the system and no double dipping. • Mr Schubert expressed the view that double dipping occurs when a hybrid facility receives credit for something and is using the same facility to obtain credit for something else at the same time, and those things are not complimentary or aligned. • Mr Ross agreed, stating the measure may then need to be the same so one counters the other rather than having both a DSP and IRCR benefit. The Chair clarified there are two separate concepts: o During IRCR intervals –double dipping should not be allowed for taking an action to reduce IRCR and receiving DSP capacity credit payments for the same action. o During obligation intervals for a DSP and ESR –on a normal day where there are no IRCR intervals, there should be no refunds unless a participant is not responding to dispatch instruction/notification. • Mr Price took a question on notice about whether the forward planning and visibility that applies to a hybrid facility is hampered with the inclusion of a load which is part of a scheduled or semi-scheduled facility. The Chair recommended that the working group considers various scenarios in which a facility was predominantly injecting versus predominantly withdrawing during intervals, and how responses would be measured. • Mr Martin offered to help develop these scenarios for working group consideration. The Chair summarised the working group principles: • Loads should have a choice as to how they participate in the market, and whether they choose to invest in a storage component on a load site. • Those hybrids or loads should not benefit from the same action (double-dip), for example simultaneously getting certified as a DSP and having IRCR reduction benefited. • If loads are remunerated for an action, the system should also benefit.	

Item	Subject	Action
	Mr Thomas stated that the precision with which distinction can be drawn between double dipping versus stacking versus coincident value opportunities will depend on how stakeholders perceive their exposure to penalties: • Participants might take risks if they perceive a penalty or a capacity value that is very low. • Whether participants should take such risks is a grey area but it can be made black and white (despite uncapped penalties being unpopular). • There will always be some prospective gaming or opportunism that might need to be factored into discussion on double dipping. Mr Ditric added that IRCR consumption intervals are not necessarily known until they have occurred, so there is no clear view of what the penalty periods may be until the hot season is over. • Mr Alexander clarified whether facilities, which have loads and storage, could only participate as a hybrid, except where they pay for separate connections. The Chair confirmed that this was the case, noting that this would also require two separate Western Power meters and is dependent on whether this can to be accommodated by the network. • Mr Schubert asked whether there could be separate metering at the connection point. The Chair said separate metering could be achieved if a Western Power meter is installed and the components are treated separately, but changes to the rules would be required. • Mr Alexander said that lots of industrial sites could see value in this option, but noted that it might be worth placing a cap on the storage size. The Chair noted the discussion on hybrids would continue in the next meeting, with the group working through the various scenarios for hybrid facility operations across each of the aspects of the WEM.	
5	**Curtailable access for loads discussion** Mr Ditric provided an overview of the issue at hand, highlighting: o The two purposes of the NAQ are determining network capacity access for the purposes of capacity credits; and providing investment certainty for capacity providers by providing a priority order for capacity credits. o Loads are considered as part of the NAQ calculation but only in that they alleviate or contribute to network congestion. o Western Power has difficulty connecting new generation unless applicants are willing to wait in the competing applications group (CAG) process, or fund network augmentation to increase capacity to handle more generation. The NAQ allows facilities to connect on a constrained basis and make most of existing network capacity. o Loads may be facing similar connection issues. It may, therefore, be necessary to consider a framework for loads to connect on a constrained basis, similar to how NAQ works for generation.	

Item	Subject	Action
	o The introduction of constrained access for loads should speed up connection for loads and reduce the cost of connection. o Loads would be constrained largely in times of peak demand, network outages or some other limitation to the network. o The NAQ recognises a participant who funds a network augmentation and gives them priority rights. There is a question about whether this is required for loads. • Mr Price clarified that the NAQ only applies to the capacity mechanism, not in real-time operations. Therefore, the NAQ does not automatically give a participant any rights to the network in real-time. The Chair added that a participant might be able to export at a level higher than their NAQ. Mr Ditric invited discussion on ways to connect loads more quickly and cheaply than under the current arrangement. • Mr Schubert stated Western Power is already offering constrained access schemes to Eastern Goldfields' loads with their own diesel generation. The Chair queried whether AEMO has any visibility of that arrangement or takes it into account in planning activities including the long term (LT) PASA if those curtailments are expected during the peak in the SWIS/WEM. • Mr Price clarified the objective of the LT PASA is to quantify demand that has to be served at peak and then seeks to procure the capacity to serve it. He added that the NAQ and network limits that might impact the ability to serve a customer would, therefore, not be reflected in the system-normal state. The Chair stated that this does not mean network peak events do not coincide with system peak events. • Mr Huxtable indicated that there were definitely localised network issues with runback schemes and they could be coincidental but typically were not. • Mr Price clarified that there are non-reference services, under which loads can be curtailed at peak, which are reflected in the NAQ. The Chair queried whether those loads should also be taken into account in planning studies given that, if they are taken into account in the NAQ calculations, there is presumably some certainty that they will not be available at peak. • Mr Price said that by virtue of having such a runback scheme it is certain they will not be available at peak. Mr Price added that those loads are also taken into account in determining available capacity for a particular year. • Mr Butler took an action to investigate the technical operation of the constraint algorithm in the NAQ and to discuss this with the working group in future meetings.	

The Chair recommended that the working group should consider:

- how network constraints and curtailment schemes could/should be used in future given the network is now constrained by thermal and other limits;
- whether a coordination role is useful to ensure loads connected under a curtailable regime in the future are taken into account; and
- impact of curtailable loads on the market and options to improve transparency/visibility.

Working group members broadly agreed that a centralized, market based approach would be more efficient than a bespoke scheme, particularly if it is run at a system wide level.

The Chair sought to understand how many curtailable loads there were and how large they were, and asked Western Power to provide some information without revealing details of particular loads. She added that the SWISDA also suggested loads may not be able to connect to the network unless either network reinforcement is undertaken, or they agree to some kind of interruptible arrangement.

Mr Ditric asked if a participant can be curtailed at peak under a contract, whether they should be dispatched as part of a dispatch order so that they are visible.

- Ms Kogon stated that she did not see barriers preventing a more centralised market based approach given that loads can register as scheduled or semi-scheduled facilities.
- Mr Price questioned whether a framework allowing bidirectional participation in injection and withdrawal offers is appropriate for loads, and whether such a framework would capture partially controllable loads.

The Chair suggested that the working group needs to map out the process for a participant agreeing to an arrangement in which its load can be curtailed at peak, including the role of Western Power and of AEMO in the planning and NAQ process.

- Mr Butler said that AEMO was addressing the same challenge in respect of DER.

In the Teams chat, Mr Schubert recommended discussion on the pros and cons of different network locations for storage, given storage can only even out demand upstream relative to normal electricity flow during peak demand:

- Mr Schubert asked if Western Power could provide the working group with a table of typical network circuits' average utilisation to indicate how much spare capacity was available.

Ms Kogon replied that she will seek advice from Western Power’s SMEs on this request.

Mr Ditric asked whether the working group should consider constrained load access beyond just the capacity mechanism.

Mr Ditric asked whether the working group should consider constrained load access beyond just the capacity mechanism.

Mr Ditric queried whether constrained loads will be limited as part of constraint equations or will they be considered firm capacity.

Item	Subject	Action
	The Chair expressed the view that there may need to be constraint equations for loads as well as generation. • Mr Butler highlighted the problem around coordination between RTM dispatch and what is effectively a network service, which is really the avoidance of a cost in the case of constraint. The group noted that some work is required to consider coordination versus dispatching loads, and what constitutes participation in the market. The Chair asked why RTM dispatch would be treated any differently to generators by simply applying constraint equations and making sure they are run back in the market, which they would be even if they were not on a constrained regime. • Mr Price suggested that loads appear on the right side of constraint equations and so would not be modifiable in dispatch. The question was whether they should appear on the left side and get co-optimised on the basis of offers for price they are willing to withdraw for. The Chair made the following additional points: o The working group needs to determine what appetite there is for the participation of loads in the energy market. o If a participant has a curtailable load, they need to know whether they can provide DSP services and benefit from DSP services as well as IRCR. o It is not clear whether currently a load that wants the benefit of curtailment in a DSP can in fact participate in the RTM and/or ESS. .	
6	**Prioritisation of topics for future meetings** Mr Ditric and the Chair outlined the following questions arising from the RCM Review, seeking input from the working group on which issues should take priority: • Questions concerning additional services to provide minimum demand, which can include load increasing and load shifting as well as RCM services. • Questions concerning DSP obligations, particularly with reference to dynamic baseline design and the 2-hour activation notice. The working group agreed that: • Minimum demand services were the higher priority because there was presently an NCESS call for them – these should be scheduled for July; and • the role of DSR in STEM was a lower priority and should be discussed in August. Other topics agreed to be discussed in future meetings include: • whether DSPs can participate in the RTM and if not, what must be done to allow them to do so – EnelX agreed to provide examples of DRS participation in other markets;	

Item	Subject	Action
	• whether adequate price signals can/should incentivise participation of DER, flexible loads and distributed storage, rather than being used in emergency situations; • participation of DSR, VPPs, hybrids and hydrogen production facilities in RTM and ESS markets, including how in the future flexible load can have a prominent role in the market. The Chair suggested that the starting point for inquiry by the working group should be: • Under the current rules, can a DSP with capacity credits participate in the RTM, STEM, and the rest of the energy market services; • If DSPs can't currently participate in these markets, how can these barriers be removed. The Chair scheduled the next two meetings for 5 July 2023 and 2 August 2023	
12	**Next Steps** **Actions:** • **Schedule 5 July 2023 and 2 August 2023 meetings** • **Prepare slides for 5 July 2023 meeting and issue a week prior** • **Prepare and distribute draft minutes for working group review**	**DSRRWG Secretariat**
	• **Provide the working group with a table of average utilisation values for typical network circuits**	**Western Power**

The meeting closed at 11:31am

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

Agenda Item 7(a): Overview of Rule Change Proposals (as of 13 July 2023)

Market Advisory Committee (**MAC**) Meeting 2023_07_20

- Changes to the report since the previous MAC meeting are shown in red font.
- The next steps and the timing for the next steps are provided for Rule Change Proposals that are currently being actively progressed by the Coordinator of Energy (**Coordinator**) or the Minister.

Indicative Rule Change Activity Until the Next MAC Meeting

Reference	Title	Events	Indicative Timing
RC_2014_05	Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price	Close of second period submissions	28/07/2023
RC_2018_03	Capacity Credit Allocation Methodology for Intermittent Generators	Close of second period submissions	28/07/2023

Rule Change Proposals Commenced since the Report presented at the last MAC Meeting

Reference	Submitted	Proponent	Title	Commenced
None				

Rule Change Proposals Awaiting Commencement

Reference	Submitted	Proponent	Title	Commencement
None				

Rule Change Proposals Rejected since Report presented at the last MAC Meeting

Reference	Submitted	Proponent	Title	Rejected
None				

Rule Change Proposals Awaiting Approval by the Minister

Reference	Submitted	Proponent	Title	Approval Due Date
None				

Formally Submitted Rule Change Proposal

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Fast Track Rule Change Proposals with Consultation Period Closed						
None						
Fast Track Rule Change Proposals with Consultation Period Open						
None						
Standard Rule Change Proposals with Second Submission Period Closed						
RC_2019_03	17/12/2020	ERA	Method used for the assignment of Certified Reserve Capacity to Intermittent Generators	High	Publication of Final Rule Change Report	30/09/2023
Standard Rule Change Proposals with Second Submission Period Open						
RC_2014_05	02/12/2014	IMO	Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price	Medium	Close of second period submissions	28/07/2023

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Close of second period submissions	28/07/2023
Standard Rule Change Proposals with First Submission Period Closed						
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	Medium	Publication of Draft Rule Change Report	30/09/2023
Standard Rule Change Proposals with the First Submission Period Open						
None						

Pre-Rule Change Proposals

Reference	Proponent	Description	Next Step	Date
None				

Rule Changes Made by the Minister and Awaiting Commencement

Gazette	Date	Title	Commencement
2023/48	28/04/2023	Wholesale Electricity Market Amendment (Supplementary Capacity) Rules 2023	• Schedule C will commence at times specified by the Minister in notices published in the Gazette
2023/37	31/03/2023	Wholesale Electricity Market Amendment (Tranche 6A Amendments) Rules 2023	• Schedule B will commence at times specified by the Minister in notices published in the Gazette
2022/184	20/12/2022	Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022	• Schedule E will commence at times specified by the Minister in notices published in the Gazette
2021/212	17/12/2021	Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021	• Schedule H will commence on 01/10/2023. • Schedule I will commence at times specified by the Minister in notices published in the Gazette.
2021/166	28/09/2021	Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 2) Rules 2021	• Schedule G will commence at times specified by the Minister in notices published in the Gazette.
2021/96	28/05/2021	Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 1) Rules 2021	• Schedule E will commence at times specified by the Minister in notices published in the Gazette.
20201/17	18/01/2021	Wholesale Electricity Market Amendment (Governance) Rules 2021	• Schedule C will commence immediately after the commencement of the Amending Rules in clauses 50 and 62 of Schedule C of the *Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020.*
2020/214	24/12/2020	Wholesale Electricity Market Amendment (Tranches 2 and 3	• Amending Rules in Schedule C will commence at the times specified by the Minister in notices published in the Gazette.

Gazette	Date	Title	Commencement
		Amendments) Rules 2020	

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

Agenda Item 8: Approval Terms of Reference for the WEM Investment Certainty Review Working Group

Market Advisory Committee (MAC) Meeting 2023_07_20

Purpose

- For EPWA to provide the MAC with the updated Scope of Works for the Wholesale Energy Market Investment Certainty (WIC) Review.
- For the MAC to approve:
  - the establishment of a Working Group to assist with the WIC Review; and
  - the Terms of Reference (TOR) for the WIC Review Working Group.

Recommendation

That the MAC:

(1) notes the final Scope of Works for the WIC Review (Attachment 1);

(2) approves the establishment of the WIC Review Working Group, and

(3) approves the TOR for the WIC Review Working Group (Attachment 2).

Background

- Energy Policy WA has developed a draft Scope of Works for the WIC Review and consulted with the MAC on this draft on 8 June 2023.
  - The MAC supported the draft Scope of Works and provided some comments, which have been incorporated into the final Scope of Works.
- The Coordinator has approved the Scope of Works as amended after the 8 June MAC meeting (**Attachment 1**).
- The MAC Secretariat has developed draft Terms of Reference for a WIC Review Working Group (**Attachment 2**).
- Moving Forward:
  - the MAC Secretariat will establish the WIC Review Working Group following approval of the Terms of Reference;
  - Energy Policy WA will Chair the Working Group;
  - the MAC Secretariat will advise stakeholders that they may nominate representatives on the Working Group;
  - Market Participants and other interested stakeholder may nominate a person to be part of the Working Group, and
  - the Working Group will commence operation in August 2023.

Attachments

(1) Scope of Works

(2) draft Terms of Reference

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

Scope of Work for the WEM Investment Certainty Review

1. Introduction

The Coordinator of Energy (Coordinator) is conducting the Wholesale Electricity Market (WEM) Investment Certainty (WIC) Review under clause 2.2D.1 of the WEM Rules. Clause 2.2D.1(h) confers the function on the Coordinator to consider and, in consultation with the Market Advisory Committee (MAC), progress the evolution and development of the WEM and the WEM Rules.

The WIC Review aims to ensure that the WEM will provide incentives for sufficient new renewable capacity, while maintaining system security and reliability and without unduly increasing the cost to consumers. The WIC Review will address issues that were recognised in the Reserve Capacity Mechanism Review and will consider the following five specific reforms that were announced by the Minister for Energy on 9 May 2023:

(1) reviewing the Reserve Capacity Price (RCP) curve to determine if it needs to be adjusted to send sharper signals for investment when demand for new capacity is stronger;

(2) a 10-year RCP guarantee for new technologies, such as long-duration storage;

(3) a wholesale energy price guarantee for renewable generators, to top up their energy revenues as WEM prices start to decline, in return for them firming up their capacity;

(4) emission thresholds for existing and new high emission technologies in the WEM; and

(5) a 10-year exemption from the emission thresholds for existing flexible gas plants that qualify to provide the new flexibility service.

The Coordinator is conducting the WIC Review in 2023 and 2024 and intends to develop changes to the WEM Rules and submit these for approval by the Minister in 2024.

2. Background

2.1 Energy Market Transformation

Electricity markets around the world are undergoing a major transition in the move to a net zero emissions energy sector. The South West Interconnected System (SWIS) continues to experience a significant uptake of distributed photovoltaic and large scale wind generation.

As indicated in the SWIS Demand Assessment that was released by the Minister for Energy on 9 May 2023,[1] a number of factors are likely to influence demand growth in the SWIS in the coming decade, such as the electrification of major industrial processes.

At the same time, the electricity supply mix in the SWIS is rapidly changing with:

- the forthcoming exit of baseload fossil fuelled generators (coal), followed by the progressive exit of the rest of the fossil fuelled facilities (gas and diesel);
- the current and continued entry of renewable intermittent generation (wind and solar); and

---

[1] SWIS Demand Assessment 2023 to 2042 (www.wa.gov.au).

- the uptake of electric storage resources (ESR).

Significant network, renewable generation and ESR investment will be required in the SWIS over the next decade to continue to deliver on the energy trilemma of reliable, affordable and environmentally responsible electricity supply.

The Coordinator has commenced a number of electricity market reviews since the start of 2022 to address issues associated with this electricity transformation, including:

- the Reserve Capacity Mechanism (RCM) Review;[2]
- the Cost Allocation Review;[3]
- the Market Power Mitigation Strategy review;[4]
- the Supplementary Reserve Capacity (SRC) Review;[5] and
- the Demand Side Response (DSR) Review.[6]

These reviews address a number of issues associated with the transformation of the SWIS, but have also highlighted the need for further WEM reforms to incentivise investment in new renewable energy facilities and to help the Government achieve its decarbonisation targets, while maintaining system security and reliability without unduly increasing costs to consumers.

2.2 Investment Certainty

Concerns have been raised about the ability of the WEM to deliver price signals that drive efficient investment in renewable generation capacity because of an increased risk that sufficient revenue will not be available to make the investments viable due to:

- the potential decrease in energy market prices when renewable generators with low operating costs set the market price more frequently in the future; and
- the lack of a mechanism to price the market externality associated with greenhouse gas emissions.

EPWA conducted some preliminary economic modelling as part of the RCM Review to forecast the financial viability of new intermittent renewable generation and ESR developments.[7] While this modelling was based on conservative assumptions, it indicated the following:

---

2 Information on the RCM Review is available at Reserve Capacity Mechanism Review (www.wa.gov.au). The MAC established a RCM Review Working Group (RCMRWG) to assist with this review. Information on the CARWG is available at. Reserve Capacity Mechanism Review Working Group (www.wa.gov.au).

3 Information on the Cost Allocation Review is available at Cost Allocation Review (www.wa.gov.au). The MAC established a Cost Allocation Review Working Group (CARWG) to assist with this review. Information on the CARWG is available at Cost Allocation Review Working Group (www.wa.gov.au).

4 Information on the Market Power Mitigation Strategy is available at Market Power Mitigation Strategy (www.wa.gov.au).

5 Information on the SRC Review is available at Supplementary Reserve Capacity Review (www.wa.gov.au).

6 Information on the DSR Review is available at Demand Side Response Review (www.wa.gov.au). The MAC established a Demand Side Response Review Working Group (DSRRWG) to assist with this review. Information on the DSRRWG is available at Demand Side Response Review Working Group (www.wa.gov.au).

7 See section 9 of the *Reserve Capacity Mechanism Review Information Paper (Stage 1) and Consultation Paper (Stage 2)* , which is available at epwa_reserve_capacity_mechanism_review_information_and_consultation_paper.pdf (www.wa.gov.au).

The economic modelling under the RCM Review was deliberately conservative on the participation of renewables in non-energy services, so the revenue adequacy for renewables would likely improve with more realistic assumptions.

ESR: Revenues from the RCM (both the peak and flexible capacity products), the energy market and Essential System Service (ESS) markets are likely to be sufficient to support entry of ESR for the whole modelling horizon (to 2050).

Wind: Revenues from the RCM (the peak capacity product only), the energy market and Large-Scale Generation Certificates (LGCs) under the Renewable Energy Target (RET) are likely to be sufficient to support entry of new wind Facilities until around 2030.

Building sufficient new wind Facilities to meet the Planning Criterion past 2030 will likely result in decreasing energy prices to the point that total WEM revenues may be insufficient to cover the fixed and capital costs for new wind Facilities.

Solar: Revenues from the RCM (the peak capacity product only), the energy market and LGCs are likely insufficient to support entry of new utility scale solar generators for the whole modelling horizon.

This risk of non-recovery of the full costs could stall investment in new renewable generation capacity at the required scale and in the required timeframe to meet the State decarbonisation targets. The WIC Review will consider initiatives to address these concerns.

2.3 Emissions Reductions

The RET is the current national scheme to incentivise emissions reductions.[8] At present, the RET is due to cease in 2030, at which point there will be no specific mechanism to incentivise emissions reductions by electricity generators in Western Australia.

The Minister provided a draft *Statement of Policy Principles: Penalties for High Emission Technologies in the Wholesale Electricity Market* (Policy Statement) to the Coordinator in September 2022 and the Coordinator consulted with the MAC on the draft Policy Statement.[9]

Energy Policy WA (EPWA) subsequently commenced its assessment of options to implement this policy, and consulted on this as part of the RCM Review.[10]

The MAC accepted that implementing the penalty on high emissions technologies by establishing two emissions thresholds – an emissions rate threshold (tCO_2e/MWh) and an emissions quantity threshold (tCO_2e/MW) – and only providing Capacity Credits to Facilities that are below the thresholds was the preferred option. However, EPWA did not arrive at a final design for this threshold arrangement under the RCM Review.

The WIC Review will consider initiatives to address the Government’s policy to move to a net zero emissions energy sector.

3. Project Scope

The Government is delivering on the outcomes of a number of WEM reviews, the most significant of which is the review of the RCM.

8 The RET is an Australian Government scheme that is administered by the Clean Energy Regulator and is designed to reduce greenhouse gas emissions from the electricity sector and to encourage the additional renewable generation. Further information is available at About the Renewable Energy Target (cleanenergyregulator.gov.au).

9 The draft Policy Statement was tabled for discussion by the MAC on 13 October 2022 (Out-of-Session Meeting Papers.pdf (www.wa.gov.au)) and a revised draft on 13 December 2022 (MAC 2022_12_13 - Combined Meeting Papers.pdf (www.wa.gov.au)).

10 The MAC and RCMRWG discussed development of a penalty on high emissions technologies, identified six options, and recommended an emissions threshold as the preferred approach. For more information, see the papers for the MAC meetings on 9 August 2022, 13 December 2022, 2 February 2023 and 16 March 2023; and the papers for the RCMRWG meetings on 13 October 2022, 24 November 2022, 2 March 2023 and 22 March 2023.

The RCM Review will result in more incentives for investment in the type of capacity needed by the WEM. The proposed flexibility product, which will top up capacity revenues for flexible capacity, such as storage and flexible gas plant, is an example of the kind of incentives delivered through the RCM Review.

The RCM Review also assessed options to implement penalties for high emissions technologies, and has highlighted a number of issues related to certainty for investment in reserve capacity. While not directly part of the RCM Review, these issues require attention.

As a result, Government is considering a package of specific WEM reform initiatives aimed at enhancing investment certainty for renewable and storage proponents. Better certainty for investors in new flexible energy technologies will help meet emission reduction targets while maintaining reliability in the SWIS. These initiatives were announced by the Minister for Energy on 9 May 2023.

3.1 Initiative 1: Changing the Reserve Capacity Price curve so it sends sharper signals for investment when demand for new capacity is stronger

Objective

The current RCP curve was established in the WEM Rules when there was significant excess of reserve capacity in the WEM. Recent market developments, including fuel supply limitations and increases in forecast demand, have resulted in capacity margins being tighter than the WEM has typically experienced.

While the existing mechanisms in the WEM are designed to address such circumstances, the objective of Initiative 1 is to change the RCP curve so it is steeper if capacity is short but flatter if capacity is oversupplied. This will provide stronger incentives for investment in capacity by increasing the RCP faster when AEMO projects a capacity “shortage”.

Issues

The review of the RCP will consider:

(1) whether the overall methodology for setting the RCP is appropriate;

(2) whether the shape of the price curve (i.e. the segments of the price curve) is appropriate;

(3) whether the parameters for the price curve are appropriate, including:

  (a) the Price Cap;

  (b) the Absolute Zero Point;

  (c) the Economic Zero Point;

(4) whether the Transitional Arrangements are appropriate (i.e. the price floor and price cap);

(5) what changes need to be made to the WEM Rules to enable the outcomes of the review of the RCP; and

(6) any other RCP-related issues identified in the course of the review.

3.2 Initiative 2: A 10-year RCP guarantee for new technologies, such as long-duration storage

Objective

Under the current WEM Rules, proponents of new facilities can request to fix their RCP for five years. The objective of Initiative 2 is to allow proponents of new flexible technologies, such as long-duration storage, to increase the length of the RCP to 10 years, from five.

This will provide longer price certainty for long-duration storage, additional incentive for investment in these technologies, and allow more variable renewable generation to connect without compromising reliability.

Issues

The options for implementing this initiative will examine:

(1) what "new" technologies should be eligible for a 10-year RCP guarantee; and

(2) what does "long-duration" storage mean in the application of this initiative and should this change over time.

3.3 Initiative 3: A wholesale energy price guarantee for renewable generators, to top up their energy revenues as WEM prices start to decline, in return for them firming up their capacity

Objective

The RCM Review modelling indicated that the profitability of wind and solar generation may decrease in the later part of the decade, potentially resulting in insufficient WEM revenues for renewable generation past 2030. This is driven by:

- a potential decrease in average wholesale electricity prices (renewable generators have very low variable cost, so WEM energy prices are likely to rapidly decline as fossil fuel plant exits the market); and
- the lack of a mechanism to price the market externality associated with greenhouse gas emissions once the LGC revenues are not available.

The objective of Initiative 3 is to consider the need for a "top-up" of WEM revenues for renewable generators to address the risk that the renewable generators may not recover enough revenue to justify investment due to the potential for declining WEM prices. The intent is to create revenue certainty for renewable generators, while not increasing energy prices.

The top-up of WEM revenues would be available to renewable generators that can demonstrate in the RCM certification that they have firmed up their capacity by, for example, contracting with a storage facility.

Issues

The development of options for the application of this initiative is to consider:

(1) the overall approach to the scheme;

(2) when should the scheme commence and when should it end;

(3) under what circumstances should the top-up be provided, including:

    (a) what should be the trigger for the commencement of the scheme;

    (b) which types of technologies should be eligible;

(4) what firming requirements should be put in place;

(5) how should the top-up be calculated, including determining:

    (a) when there is a revenue adequacy problem and what is the magnitude of the problem;

(b) the projected revenues for an eligible Facility, including from:

(i) the RCM (both the peak and flexible capacity products);

(ii) the energy market;

(iii) the ESS markets;

(iv) LGCs or any other mechanism(s) to price carbon emissions externalities;

(6) how should the cost of the top-up be recovered in the WEM;

(7) how should the scheme be administered;

(8) what arrangements are required to amend or cease the scheme if another (State and/or Commonwealth) regime is established to price the carbon externality;

(9) the design of the Amending Rules to implement the scheme and

(10) any other issues that are identified in the course of developing the scheme.

3.4 Initiative 4: Emission thresholds for existing and new high emission technologies in the WEM

Objective

The objective of Initiative 4 is to introduce emission thresholds into the WEM Rules for both existing and new generators and to only provide Capacity Credits to facilities with emissions below these thresholds. The intent would be to gradually reduce the thresholds for existing facilities.

Signalling the emissions thresholds years in advance will provide increased certainty to AEMO of the ongoing viability of existing thermal generators and when existing generators are likely to no longer be available to contribute to the Reserve Capacity Target. This would also create opportunity for low emission technologies, such as renewable generators, to enter the market once fossil fuel plants lose their Capacity Credits.

Issues

The design of the Emissions Thresholds Scheme is to be based on the work on the penalties on high emissions technologies that was done under the RCM Review and is to include:

(1) the type(s) of thresholds that are to apply to existing and new Facilities, including consideration of:

(a) an emissions rate threshold ($tCO2_e$/MWh);

(b) an emissions quantity threshold ($tCO2_e$/MW);

(2) the level of the thresholds for existing and new Facilities at the commencement of the scheme;

(3) the rate of decline for the thresholds over time;

(4) timing for commencement of the arrangements;

(5) the design of the Amending Rules to implement the Emissions Thresholds Scheme; and

(6) any other issues identified in the course of developing the Emissions Thresholds Scheme.

3.5 Initiative 5: Introducing a 10-year exemption from the emission thresholds for existing flexible gas plants that qualify to provide the new flexibility service

Objective

The objective of Initiative 5 is to ensure an orderly transition to a zero carbon emissions system and to maintain system reliability, by providing a 10-year exemption from the emission thresholds for existing flexible gas plant.

This will ensure that the flexible gas plant that is required to maintain reliability does not prematurely exit the market. Together with the penalties regime, this would allow the exit of high emission generators from the RCM, while maintaining the presence of efficient gas generation and reliability in the WEM.

Issues

The design of this initiative is to include:

(1) the conditions of the exemption and whether it should apply to existing plant only;

(2) timing for commencement of the arrangements;

(3) the design of the Amending Rules to implement the Emissions Thresholds Scheme; and

(4) any other issues identified in the course of developing the Emissions Thresholds Scheme.

4. General Principle

All reforms under the WIC Review must meet the Wholesale Market Objectives, as well as being simple, flexible, sustainable and practical.

The Government is currently undertaking a process to enact a new State Electricity Objective[11] that will replace the Wholesale Market Objectives. The general principle will be that all of the above reforms must be consistent with the State Electricity Objective.

5. Out of Scope

The following is Out of Scope for the WIC Review:

- a review of the fundamentals of the WEM established by the Energy Reform Taskforce;
- matters already covered by other market development reviews; and
- recommending direct cash injections or other direct subsidies for new projects.

---

[11] The proposed State Electricity Objective is to:

> promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity in relation to:
>
> - the quality, safety, security and reliability of supply of electricity; and
> - the price of electricity; and
> - the environment, including the reduction in greenhouse gas emissions.

Further information on the process to enact the new State Electricity Objective is available at [Project Eagle Energy and Governance Legislation Reform (www.wa.gov.au)].

6. Stakeholder Engagement

EPWA will consult on the WIC Review via:

- discussions with the MAC;
- forming a MAC working group – the WEM Investment Certainty Working Group (WICWG) – to discuss:
  - the market modelling approach and assumptions to support the WIC Review;
  - detailed design elements of all five reforms initiatives under the WIC Review;
- publication of a public Consultation Paper and seeking submissions on that paper;
- publication of an Information Paper to advise on the outcomes of the WIC Review; and
- publication of draft Amending Rules to implement the outcomes of the WIC Review and seeking submissions on the draft Amending Rules.

7. Project Schedule

Tasks/Milestones	Timing
(1) Preliminary Steps	
(a) MAC comments on the Scope of Work for the review	8 June 2023
(b) Coordinator approval and publication of the Scope of Work	30 June 2023
(c) MAC approval of the Terms of Reference for the WICWG	20 July 2023
(d) Appointment of consultants	28 July 2023
(e) First meeting of the WICWG	10 August 2023
(2) Initial Assessment	
(a) Initiatives (2), (4) and (5)	August 2023 – November 2023
(b) Initiative (1)	November 2023 – December 2023
(c) Initiative (3)	December 2023 – March 2024
(3) Consultation Paper	
(a) Consult with the MAC on a draft of the Consultation Paper	April 2024
(b) Publish the Consultation Paper	April 2024
(c) Submissions on the Consultation Paper	May 2024
(4) Further Assessment	
(a) All Initiatives	May – June 2024
(5) Information Paper and Draft Amending Rules	
(a) Consult with the MAC on: • a draft of the Information Paper • draft WEM Amending Rules	June 2024

Tasks/Milestones	Timing
(b) Publish the Information Paper and draft WEM Amending Rules	July 2024
(c) Submissions on the draft WEM Amending Rules	August 2024
(6) Finalisation and Commencement	
(a) Ministerial approval of the WEM Amending Rules	September 2024
(b) Commencement	Various

Terms of Reference
WEM Investment Certainty Review Working Group

13 July 2023

1. Background

The Coordinator of Energy (Coordinator) is conducting the Wholesale Electricity Market (WEM) Investment Certainty (WIC) Review under clause 2.2D.1 of the WEM Rules. Clause 2.2D.1(h) confers the function on the Coordinator to consider and, in consultation with the Market Advisory Committee (MAC), progress the evolution and development of the WEM and the WEM Rules.

The WIC Review aims to ensure that the WEM continues to provide incentives for new renewable capacity, while maintaining system security and reliability and without unduly increasing the cost to consumers.

Energy Policy WA developed a scope of works for the WIC Review in consultation with the MAC. The scope of works is available on the Coordinator's Website at: Wholesale Electricity Market Investment Certainty Review (www.wa.gov.au).

The scope of works for the WIC Review includes:

- objectives and guiding principles for the review;
- issues to be considered;
- stakeholder engagement; and
- the project schedule.

The MAC has established the WIC Review Working Group under clause 2.3.17(a) of the WEM Rules to assist the Coordinator with the WIC Review.

2. Scope of the Working Group

The WIC Review Working Group has been established to provide expert advice and analysis on issues that were recognised in the Reserve Capacity Mechanism Review and will consider the following five specific reforms that were announced by the Minister for Energy on 9 May 2023:

(1) reviewing the Reserve Capacity Price (RCP) curve to determine if it needs to be adjusted to send sharper signals for investment when demand for new capacity is stronger;

(2) a 10-year RCP guarantee for new technologies, such as long-duration storage;

(3) a wholesale energy price guarantee for renewable generators, to top up their energy revenues as WEM prices start to decline, in return for them firming up their capacity;

(4) emission thresholds for existing and new high emission technologies in the WEM; and

(5) a 10-year exemption from the emission thresholds for existing flexible gas plants that qualify to provide the new flexibility service.

3. Membership

Energy Policy WA will Chair of the WIC Review Working Group.

Market Participants and other interested stakeholders may nominate a person for membership on the WIC Review Working Group for approval by the Chair of the WIC Review Working Group.

All members of the WIC Working Group are required to contribute their time and resources to complete specific analysis and other tasks as requested by the Chair.

There are no restrictions on the number of WIC Review Working Group members. However, the Chair of the WIC Review Working Group may only approve one member from each organisation.

The Chair of the WIC Review Working Group will have discretion to allow additional subject matter experts or consultants to attend specific meetings or workshops, either generally or on a case-by-case basis.

Energy Policy WA will provide administrative support to the WIC Review Working Group.

4. Documentation

Energy Policy WA will establish a WIC Review Working Group webpage on its website. Any discussion papers, meeting papers and meeting minutes will be posted to this page.

Market Participants and other stakeholders may register with Energy Policy WA to receive email communications regarding the WIC Review Working Group, including notices of publication of papers on the WIC Review Working Group webpage.

5. Responsibilities of Meeting Attendees

A person attending a WIC Review Working Group meeting is expected to:

- have suitable knowledge and experience to engage in and contribute to discussions relevant to the specific meeting;
- prepare for the meeting, including by reading any meeting papers distributed before the meeting;
- participate as a general industry representative rather than representing their company's interests; and
- complete actions requested by the Chair, which may include undertaking of analysis or preparation of papers for discussion by the Working Group.

6. Administration

Energy Policy WA will provide secretariat support for the WIC Review Working Group.

Energy Policy WA will ensure contact details for the WIC Review Working Group are maintained on the WIC Review Working Group webpage.

The Working Group will meet at least monthly. The Chair of the WIC Review Working Group will convene meetings of the working group in accordance with the timelines in the scope of works for the WIC Review.

Energy Policy WA will prepare and distribute all meeting correspondence to the WIC Review Working Group via email. Energy Policy WA will endeavour to provide the following documentation by email to the WIC Review Working Group members:

- notices of meetings, agendas, and relevant meeting papers at least 5 Business Days prior to the meeting; and
- key outcomes and actions emerging from each meeting no more than 5 Business Days following the meeting.

All meeting documentation will be published on Energy Policy WA's website as soon as practicable after it has been sent to the WIC Review Working Group members.

Meetings will generally be held online via TEAMS but may sometimes be held in person. Meeting minutes are to record meeting attendance, main outcomes of discussion, agreed recommendations to the MAC and action items. Meetings will be recorded to assist with development of minutes.

7. Reporting Arrangements

The WIC Review Working Group Chair must provide a report to the MAC on the WIC Review Working Group's activities at each MAC meeting. The reports must include, at a minimum:

- details of all WIC Review Working Group meetings since the last report to the MAC, including the date of the meeting and the key outputs of each meeting;
- the date of the next meeting and the issues to be considered (if known); and
- any recommendations from the Working Group to the MAC.

8. Projected Timeline

Task/Milestone	Timing
(1) Preliminary Steps	
(a) MAC comments on the Scope of Work for the review	8 June 2023
(b) Coordinator approval and publication of the Scope of Work	30 June 2023
(c) MAC approval of the Terms of Reference for the WICWG	20 July 2023
(d) Appointment of consultants	28 July 2023
(e) First meeting of the WICWG	10 August 2023
(2) Initial Assessment	
(a) Working Group meetings to review and analyse initiatives (2), (4) and (5)	August 2023 – November 2023
(b) Working Group meetings to review and analyse initiative (1)	November 2023 – December 2023
(c) Working Group meetings to review and analyse initiative (3)	December 2023 – March 2024

(3) Consultation Paper	
(a) Consult with the MAC on a draft of the Consultation Paper	April 2024
(b) Publish the Consultation Paper	April 2024
(c) Submissions on the Consultation Paper	May 2024
(4) Further Assessment	
(a) Working Group meetings to further asses all Initiatives	May – June 2024
(5) Information Paper and Draft Amending Rules	
(a) Consult with the MAC on: • a draft of the Information Paper • draft WEM Amending Rules	June 2024
(b) Publish the Information Paper and draft WEM Amending Rules	July 2024
(c) Submissions on the draft WEM Amending Rules	August 2024
(6) Finalisation and Commencement	
(a) Ministerial approval of the WEM Amending Rules	September 2024
(b) Commencement	Various

9. Contact Details

Rule Participants and other stakeholders may contact the WIC Review Working Group Secretariat at energymarkets@dmirs.wa.gov.au. Documentation and information related to the WIC Review Working Group will be published on Energy Policy WA's website.

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

Agenda Item 9 Update on the SRC Review

Market Advisory Committee (MAC) Meeting 2023_07_20

1. Purpose

For Energy Policy WA (EPWA) to:

- provide the MAC with an update on stage 2 of the Coordinator of Energy's (Coordinator) review of the supplementary reserve capacity (SRC) provisions of section 4.24 of the WEM Rules;
- provide a summary of feedback during consultation; and
- outline the proposed changes.

2. Recommendation

That the MAC notes:

- the feedback provided during the stage 2 consultation as presented in the Attachment 1; and
- the outcomes of Stage 2 and recommendations from the Coordinator to the Minster for changes to certain WEM Rules provisions.

3. Review of the Supplementary Reserve Capacity

3.1. Background

Clause 4.24.19 of the WEM Rules requires that after each call for tenders for supplementary capacity or otherwise acquiring Eligible Services the Coordinator must review the SRC provisions, and undertake a public consultation process on the outcomes of the review.

3.2. Process

- On 23 September 2022, AEMO commenced the SRC procurement process under section 4.24 of the WEM Rules and published an invitation for tenders from Eligible Services capable of generation or load reduction.
- On 31 January 2023, the Coordinator initiated a review of the SRC in 2 stages, with both stages now being completed:
    - Stage 1 assessed the effectiveness of the SRC procurement process.
    - Stage 2 assessed the performance of the procured SRC services.
- EPWA engaged ACIL Allen to assist with this review.
- Stage 1 of the Review was completed in April 2023 after extensive stakeholder consultation.
- At the 20 April 2023 MAC meeting, EPWA provided a summary of the outcome of stage 1 of the SRC Review that outlined:

- the comprehensive stakeholder engagement undertaken in Stage 1; and
- the consequent recommended improvements to the SRC Provisions that had been submitted to the Minister.

- On 28 April 2023, a notice was published in the Government Gazette for the commencement of the Wholesale Energy Market (Supplementary Capacity) Rules 2023, which incorporated the outcomes of Stage 1.
- Stage 2 of the Review was completed on 30 June 2023 after comprehensive stakeholder engagement that discussed possible further improvements to the SRC Provisions. The stakeholder engagement included:
  - direct consultation with AEMO throughout the review process;
  - a stakeholder questionnaire, to which EPWA received eight responses;
  - a consultation paper that included all proposed improvements, including draft Amending Rules, to which EPWA received five submissions[1]; and
  - a meeting of the Transformation Design and Operation Working Group that was held one week before the submission period for the consultation paper closed.[2]
- A summary of the feedback provided in submissions on the consultation papers including EPWA's responses is provided in Attachment 1.

3.3. Recommendation from the Coordinator to the Minister on WEM Amending Rules

- Following consideration of the stakeholder responses, the Coordinator recommended that the Minister make WEM Amending Rules that include the following improvements to the SRC procurement process and operation:
  - facilitating the availability of meter related information for performance measurement;
  - formalising testing requirements for the provision of SRC services;
  - changing the definition of Eligible Services to reduce the reference period for restricting participation of facilities that previous held Capacity Credits or Market Participants with Demand side Programmes that have previously failed to meet their Reserve Capacity Obligations; and
  - publishing the results of SRC procurement activities.
- The proposed WEM Amendment (Supplementary Reserve Capacity No. 2) Rules 2023, have been submitted to the Minister.
- EPWA expects that the Amending Rules will be gazetted late July.

3.4. Next Steps

- EPWA does not foresee next steps.

Further information on the SRC Review is available on at [Supplementary Reserve Capacity Review (www.wa.gov.au)]

---

1 All Submissions are available on here: Supplementary Reserve Capacity Review (www.wa.gov.au)

2 The presentation from the TDOWG meeting is available here: Transformation Design and Operation Working Group (www.wa.gov.au).

4. Attachments

(1) Summary of feedback in submissions on the Consultation Paper and EPWA's responses

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

Summary of Feedback in Submissions on the Consultation Paper of the Stage 2 SRC Review and EPWA's Responses

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	EPWA's Assessment
Availability of interval meter data for performance measurement				
PROPOSAL 1 EPWA proposes to require and enable Western Power to provide AEMO with the information necessary for the effective procurement and performance measurement of SRC services	4.24.18(b)	AEMO	Supportive of intent, suggested additional clause is required to overcome issues and challenges with confidentiality. AEMO also identified a need to make consistent the wording of clause 4.24.18(c) and 4.24.18B with respect to the description of a request for assistance or an assessment by Western Power.	EPWA agreed and introduced an additional Rule Change proposal to 4.24.17(k) and new Rule 4.24.7(m) to introduce the provision of consent. The Amending Rules have also been made consistent in line with AEMO's identification of an inconsistency.
		Perth Energy	No comment	
		Alinta Energy	No comment	
		Enel X	Supportive	
		Shell	No comment	
		Synergy	No comment	
		Western Power	Supportive of intent but noted challenges associated with the application of the Metering Code having precedence over the WEM Rules may make it challenging to comply with the Rule Change (and so the intent of the Rule Change would not be delivered). Agreed with AEMO that an additional Rule	See above

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	EPWA's Assessment
			Change to introduce the provision of consent to share information as part of Supplementary Capacity Contracts would assist.	
Formalisation of Testing Requirements for SRC Services				
PROPOSAL 2 EPWA proposes to amend the WEM Rules to require AEMO to activate all services as soon as practical after Supplementary Capacity Contracts are entered into.	4.24.16 (new clause)	AEMO	Confirmed during TDOWG that an alternative proposal, which would provide it with discretion to consider alternative evidence to physical activation of services as a means of confirming a service's capacity to deliver would satisfy the intent of the proposal.	EPWA agreed to amend the Rule Change proposal to provide discretion to AEMO as to how it satisfies itself that services will perform when required. This is achieved through a change in the wording of the new clause, removing the requirement for AEMO to "activate" the service and replacing it with additional drafting that permits this discretion.
		Perth Energy	Asked whether there was alternatives to activation as a means to confirm service's capacity to perform.	See above.
		Alinta Energy	Suggested service providers should be compensated for costs incurred during testing, at the contracted Activation Charge rate. Noted the addition of compliance requirements may make SRC less attractive to potential service providers and actively work against the intent of the provisions in the WEM Rules. Suggested AEMO could develop a means to prioritise submissions based on the level of certainty or surety a provider could provide that its service would perform.	EPWA considers that it is reasonable for consumers to be assured that they receive what they are paying for, particularly given a number of services' failure to perform in the 2022/2023 Hot Season. While service providers may decide to include provision for costs associated with testing in their offered price for SRC, EPWA notes that it should be the SRC provider's responsibility to demonstrate its capacity to provide the service that customers are paying for. Further, in analogous mechanism of the WEM, such as Commissioning Tests or Reserve Capacity tests, facilities do not receive extra compensation for testing.

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	EPWA's Assessment
				The suggestion to prioritise submissions based on the level of certainty or surety was noted.
		Enel X	Questioned whether individual participants in an aggregation program would need to be tested, or whether the testing was at the overall service provider. Suggested AEMO should be given discretion as to how a service's capacity to perform is confirmed (i.e. not all services need to be activated as part of a testing regime).	EPWA considers that the requirement, as amended, could be imposed on the service provider, not individual loads.
		Shell	Suggested service providers should be compensated for costs incurred during testing, at the contracted Activation Charge rate, in order to provide an incentive for AEMO to only test when necessary.	See above. Further, the amended rule changes now provide discretion to AEMO as to how it satisfies itself that services will perform, when required.
		Synergy	Asked whether there was alternatives to activation as a means to confirm service's capacity to perform.	See above.
		Western Power	No comment.	
Changes to the Definition of Eligible Services				
PROPOSAL 3 EPWA proposes to amend the WEM Rules to ease restrictions associated with participation in the	4.24.3 (a) and 4.24.3 (c) (ii)	AEMO	Noted the intent around excluding past non-performers, but questioned whether there was merit in allowing past non-performers to make offers for SRC if they can prove they have made changes to their facilities to address past issues / augment the services offered.	EPWA noted that the current Rule Change proposal was designed to ease restrictions and felt the balance was right as currently drafted.

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	EPWA's Assessment
RCM and past non-performance in Demand Side Programmes to provide greater opportunities for service providers to participate in the provision of SRC.			AEMO questioned whether excluding a service for failing to perform "just one time out of 100" was a proportionate response.	
		Perth Energy	Noted the intent around excluding past non-performers, but questioned whether there was merit in allowing past non-performers to make offers for SRC if they can prove they have made changes to their facilities to address past issues / augment the services offered.	See above.
		Alinta Energy	Noted SRC is a more risky service from a providers' perspective as there is no guarantee the service would be called, and therefore market incentives would dictate choices to participate in the RCM.	Noted.
		Enel X	Questioned whether the new testing requirements addressed this concern as service providers would only obtain contracts in the event AEMO was satisfied they could perform. In its submission Enel X suggested the restrictions on participation in the RCM / non-performance of DSPs could be further eased while reducing the capacity for service providers to game the market.	EPWA considers that testing and Eligible Services definition are separate issues, and notes that the proposed Rule Change significantly eases the current restrictions. EPWA's view is the proposed Rule Change was designed to significantly ease the current restrictions and feels that the balance is right it the proposed relaxation of these restrictions.
		Shell	No comment.	
		Synergy	No comment.	
		Western Power	No comment.	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	EPWA's Assessment
Minor Clarifying Amendments				
PROPOSAL 4 AEMO advised a number of minor clarifying amendments were required following changes to the WEM Rules Gazetted in Stage 1 of the Review to ensure the Supplementary Capacity rules reflect the intent of the provisions. These changes are: (a) Allow the assessment of responses to a call for expression of interest to be less detailed than the assessment of responses to an actual call for tender (b) Include requirements for respondents to a call for expression of interest, a call for tender or those that enter into	4.24.1B	AEMO	Supportive.	
		Perth Energy	No comment.	
		Alinta Energy	No comment.	
		Enel X	Supportive.	
		Shell	No comment.	
		Synergy	No comment.	
		Western Power	No comment.	
	4.24.7	AEMO	Supportive.	
		Perth Energy	Noted that there is a misalignment of timing between when SRC procurement occurs and when services need to be provided, and when Western Power may grant access given current resource constraints. Suggested that there could be a change to the Amending Rule which permits service providers to demonstrate they have taken steps to obtain access, as opposed to having to provide proof of actual access, during the SRC procurement.	On reflection EPWA agrees with this suggestion and has adjusted the Amending Rule to reflect this.
		Alinta Energy	No comment.	
		Enel X	Supportive.	
		Shell	No comment.	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	EPWA's Assessment
direct negotiation to provide evidence or information about their arrangements for network access		Synergy	Noted in its submission similar concerns to Perth Energy at TDOWG and provided a suggestion for a change to the Amending Rule.	See above.
		Western Power	No comment.	
(c) Ensure that the WEM Procedure covers the interaction between Western Power and stakeholders that have not yet decided to respond to a call for expression of interest, a call for tender, or to enter into direct negotiation (d) the name and contact details, provided by Western Power, which must be used when assistance or assessment by Western Power is requested.	4.24.1C	AEMO	Supportive.	
		Perth Energy	No comment.	
		Alinta Energy	No comment.	
		Enel X	No comment.	
		Shell	No comment.	
		Synergy	No comment.	
		Western Power	No comment.	
	4.24.18	AEMO	Supportive, but requested this Rule Change is deferred to after the 2023/2024 Hot Season to reduce the risk of complexities associated with tendering for SRC while simultaneously preparing a new Procedure.	EPWA has requested that the Minister defers the commencement of these changes, as requested by AEMO.
		Perth Energy	Noted that there may be some challenges with appropriately enforcing and managing respondents who "intend" to respond as this could be anyone.	EPWA notes the concern but considers that no change required.
		Alinta Energy	No comment.	
		Enel X	No comment.	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	EPWA's Assessment
		Shell	No comment.	
		Synergy	No comment.	
		Western Power	No comment.	
Publishing the Results of SRC Procurement Activities				
PROPOSAL 5 EPWA is considering whether to amend the WEM Rules to require AEMO to public certain information about Supplementary Capacity Contracts it enters into to promote market transparency.	4.24.11B	AEMO	Supportive.	
		Perth Energy	No comment.	
		Alinta Energy	No comment.	
		Enel X	Supportive.	
		Shell	No comment.	
		Synergy	No comment.	
		Western Power	No comment.	
Additional feedback				
Additional feedback The following additional matters were raised by stakeholders during the TDOWG meeting or in a written submission.	N/A	AEMO	N/A	
		Perth Energy	N/A	
		Alinta Energy	N/A	
		Enel X	N/A	
		Shell	Shell suggested an amendment to clause 4.24.13(h) of the WEM Rules (contents of Supplementary	EPWA considers that the current WEM Rules provide adequate means for service

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	EPWA's Assessment
			Capacity Contracts) to require AEMO to provide a minimum payment to service providers during events where services receive an Activation notice but are not Dispatched. This situation results in a Service Provider incurring unrecoverable costs to activate its service as additional generation cannot be sold in the STEM under the WEM Rules.	providers to negotiate terms in Supplementary Capacity Contracts which address the risks associated with service activation.
		Synergy	N/A	
		Western Power	N/A	

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

Agenda Item 10: Reserve Capacity Mechanism Review – Information Paper (Stage 2)

Market Advisory Committee (MAC) Meeting 2023_07_20

1. Purpose

To provide the MAC with the draft Reserve Capacity Mechanism (RCM) Review – Information Paper (Stage 2), for review and guidance to the Coordinator on the review outcomes.

2. Recommendation

The MAC is asked to:

(1) note the draft RCM Review Information Paper (Stage 2) (the paper) (Attachment 2) and that this paper is in a draft state (Energy Policy WA is still editing the paper);

(2) note the review outcomes of Stage 2 of the RCM Review, as summarised in Attachment 1; and

(3) provide any substantial concerns regarding the review outcomes for of Stage 2 of the RCM Review.

3. Process

The Coordinator, in consultation with the MAC, is reviewing the RCM under clause 2.2D.1 of the 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 objective of the review is to develop a 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 review is being conducted in three stages:

- Stage one focussed on the definition of reliability and the characteristics of the capacity needed in future years, including the Planning Criterion, the methods for assigning Certified Reserve Capacity[1] and the Benchmark Reserve Capacity Price.
- Stage two assessed how the outcomes of stage one affect implementation of other parts of the RCM, including outage scheduling, the refund mechanism, and Individual Reserve Capacity Requirements.

[1] The alternative methods for assigning CRC that have been identified in stage one of the RCM Review have been assessed in stage two.

- Stage three will deliver the draft WEM Amending Rules implementing the final Review Outcomes.

The paper presents the Review Outcomes of Stage 2 of the RCM Review, including the outcomes for:

- Individual Reserve Capacity Requirements;
- Matters related to Demand Side Programmes;
- The Testing, Outages and Refunds regimes;
- Other matters, including the EUE Target in the Planning Criterion, and the Determination of the BRCP Technology; and
- Removal of mandatory Expressions of Interest (new item).

An additional meeting of the RCM Review Working Group was held on 13 July 2023. The only agenda item for this meeting was to discuss the proposal to distribute collected capacity refunds to consuming participants rather than other capacity providers. The views during the meeting were finely balanced between support for and opposition to the proposal. The draft Information Paper reflects a synopsis of the discussion as well as views on the proposal recorded in submissions.

To assist with the discussion at the MAC meeting a table that lists the Review Outcomes in the Information Paper together with a high-level summary of the rationale for each Review Outcome is provided in Attachment 1.

4. Next Steps

Step	Timing
(1) Publish RCM Review Information Paper (Stage 2)	July 2023
(2) Publish the Exposure Draft of WEM Amending Rules	August 2023
(3) Consult on Exposure Drafts	August/September 2023
(4) Ministerial approval of WEM Amending Rules	October 2023
(5) Gazettal of Amending Rules	November 2023
(6) Commencement	2024 to 2025

5. Attachments

(1) Attachment 1 – Summary Table of Review Outcomes from the RCM Review Information Paper (Stage 2)

(2) Attachment 2 – Draft RCM Review Information Paper (Stage 2)

Attachment 1 – Summary Table of Review Outcomes from the RCM Review Information Paper (Stage 2)

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. 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 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.

Review Outcome	Rationale
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.	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. Talks with 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	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 as: • the ramp up requirement is expected to remain higher than the ramp down requirement; • facilities which 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.

Review Outcome	Rationale
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. (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 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.	AEMO's provision of a forecast ramp should provide enough information for participants to make decisions to curtail their ramp so as to reduce their Flexible IRCR.
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 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	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, significantly muting the incentive for loads with a variable profile 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

Review Outcome	Rationale
collocated load and storage which hold Capacity Credits will be prohibited from self-scheduling their storage purely to reduce IRCR exposure.	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 Consumption Deviation Applications (CDAs). Excluding these 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, based on the number of hours by which historical demand, scaled so peak demand equals 10% POE peak demand,	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:

Review Outcome	Rationale
exceeds the 50% POE peak demand forecast less the number of DSP Capacity Credits on issue.	• 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% 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) would be 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.

Review Outcome	Rationale
	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 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 or the 90% peak demand would address this uncertainty.
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. 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; • 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.	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: • 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 needs to be conducted: • against the new baseline, calculated from similar (but non-curtailed) intervals in recent historical data; and

Review Outcome	Rationale
	• 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) would provide incentive for participants to remedy the unavailability. There was general support to adjust the 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. 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.	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; • while 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,

Review Outcome	Rationale
	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 (FCESS) 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 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.	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. • 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.

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

Review Outcome	Rationale
	• 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%.	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.
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. 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 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
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 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 7 July 2023 RCM Review Working Group 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.

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

Reserve Capacity Mechanism Review

Information Paper (Stage 2)

July 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

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, with this stage 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 has developed and analysed policy options in conjunction with the RCM Review. Consultation on the implementation of this policy is being conducted separately.

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,[2] 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 SWIS is undergoing a major transition. The nature of the demand profile and 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 in some cases these new elements bring an increased cost, 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 https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group

Stage 2 Review Outcomes

<table>
<tr><th>Review Outcome</th><th>Rationale</th></tr>
<tr><td colspan="2">IRCR for Peak Capacity</td></tr>
<tr><td>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.</td><td>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. Talks with</td></tr>
</table>

Review Outcome	Rationale
The Coordinator's review of WEM effectiveness will include reviewing whether extreme demand events are forecast to occur outside the Hot Season.	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. (c) calculate the portfolio annual ramp contribution as the mean of the	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 as: • the ramp up requirement is expected to remain higher than the ramp down requirement; • facilities which 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 so as to reduce their Flexible IRCR.

Review Outcome	Rationale
portfolio ramp contributions determined in step (4)(b). (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 the scaling factor. 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 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, significantly muting the incentive for loads with a variable profile 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.

Review Outcome	Rationale
	Submissions generally supported the proposal for the removal of Consumption Deviation Applications (CDAs). Excluding these 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, based on the number of hours by which historical demand, scaled so peak demand equals 10% POE peak demand, exceeds the 50% POE peak demand forecast less the number of DSP Capacity Credits on issue.	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% POE

Review Outcome	Rationale
	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) would be 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 and 90% POE peak demand forecasts 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 or the 90% peak demand would address this uncertainty.
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. Flexible capacity may be tested through observation. When scheduling Reserve Capacity tests, AEMO will be required to consider:	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: • reach its certified output quantity from a ‘cold’ state at its certified maximum ramp rate; and • start, stop, and restart within its certified timings.

<table>
<tr><th>Review Outcome</th><th>Rationale</th></tr>
<tr><td>whether it would make sense to schedule a Flexible Capacity test at the same time as a Peak Capacity test;
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.</td><td>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 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) would provide incentive for participants to remedy the unavailability.
There was general support to adjust the testing regime in line with the dynamic baseline.</td></tr>
<tr><td colspan="2">Outage Planning</td></tr>
<tr><td>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.
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.</td><td>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;
while 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</td></tr>
</table>

Review Outcome	Rationale
	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 (FCESS) 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 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	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. • 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.

Review Outcome	Rationale
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.	• 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 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 • rebating refunds to consumers aligns with the distribution of Reserve Capacity Security drawdowns.

Review Outcome	Rationale
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%.	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.
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. 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.	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.

<table>
<tr><th>Review Outcome</th><th>Rationale</th></tr>
<tr><td colspan="2">RCM Expression of Interest</td></tr>
<tr><td>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 NAQ ahead of those for which no EOI was received.</td><td>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 7 July 2023 RCM Review Working Group 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.</td></tr>
</table>

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.[3]

The review is being conducted in three stages:

- Stage one focussed on the definition of reliability and the characteristics of the capacity needed in future years, including:
    - the Planning Criterion;
    - the RCM products;
    - the Benchmark Reserve Capacity Price (BRCP); and.
    - the methods for assigning Certified Reserve Capacity (CRC).[4]

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

[4] 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 has developed and analysed policy options in conjunction with the RCM Review. Consultation on the implementation of this policy is being conducted separately.

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[5], 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, that 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; and
- 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.

5 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 Temperature Dependent Load.

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.

One submission preferred that AEMO designate IRCR intervals ex-ante. EPWA still 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.

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 be implemented to exclude intervening periods in the event 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, in the future, changes in the output of utility scale intermittent generation may make up the dominant part of the ramping requirements, 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 notes the risk identified, and 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.

   (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[6] 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.

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

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

- its historical 95% POE consumption during the 200 intervals with the highest generation.

Participants can request that intervals where the load was out for maintenance are excluded from the calculation by submitting a “consumption deviation application”.

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, significantly muting the incentive for loads with a variable profile 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 were two certification approaches, depending on whether a DSP kept 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 better allowed aggregators to 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 Consumption Deviation Applications (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, 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.

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.

Consumption Deviation Applications 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 the adoption of 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 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 and 90% POE peak demands.

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.

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.[7]

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 10, 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).

Anecdotally, flexible loads, which 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.

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, while 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, based on the number of hours by which historical demand, scaled so peak demand equals the 10% POE peak demand, exceeds the 50% POE forecast peak demand less the number of DSP Capacity Credits on issue.

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.

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

DSPs are treated slightly 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;
- 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 (FSIP) 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, though 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 as a forced outage could unfairly penalize resources which 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;
- 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 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 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.
- 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 (particularly the final one) are compelling, 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, and rewards 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*. A paper discussing the allocation of Capacity Rebates[8] 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 SRC and NCESS to provide additional peak capacity, including to address potential fuel supply issues leading 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 other capacity providers.

Submissions for this proposal were polarized 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 shortfall is 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.

An additional meeting of the RCM Review Working Group was held on 13 July to discuss solely this matter. The views during the meeting were finely balanced between support for

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

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.
- 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.

EPWA acknowledges that recycling the refunds to other capacity providers may increase incentive to be available.

Taking all of the views into account, EPWA considers that distributing capacity refunds to loads is the preferred option as:

- 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;
- the capacity mechanism is designed to provide sufficient incentive for capacity to be available;
- generators being bilaterally contracted does not result in a reason for them to receive additional payments through the recycling of 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 NEM.

EPWA maintains 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.

Review Outcome 8

The target EUE percentage in the second limb of the RCM Planning Criterion will be set to 0.0002%.

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 Expression of Interest (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.
- 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 last RCM Review Working Group 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 Expression of Interest 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

Stakeholder	Stakeholder Feedback	EPWA's Response
Proposal A: Continue to set participant IRCR based on contribution to load in high demand intervals.		
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		
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.		
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		
Australian Energy Council (AEC)	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.	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.

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: • Alinta 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: • Alinta 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 dynamic operating envelopes (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.

Stakeholder	Stakeholder Feedback	EPWA's Response
Proposal I: Allow sites with collocated load and generation or storage to be Associated Loads of a DSP.		
The following stakeholders indicated that they 'support' or generally support the proposal: • Alinta Energy • Perth Energy • Expert Consumer Panel • SwitchDin • Enel X		
AEMO	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.	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.
SwitchDin	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.	RCM payments will be available to any Facility assigned CRC including VPPs capable of being registered as DSPs.
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.		

<table>
<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA’s Response</th></tr>
<tr><td colspan="3">The following stakeholders indicated that they ‘support’ or generally support the proposal:
AEMO
Perth Energy
Expert Consumer Panel
SwitchDin
Enel X</td></tr>
<tr><td>AEMO</td><td>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.</td><td>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.</td></tr>
<tr><td>Alinta Energy</td><td>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 further consideration with a view to ultimately ensuring unnecessary costs are not incurred.</td><td>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.</td></tr>
<tr><td>Enel X</td><td>Enel X strongly supports the move to measuring response against a dynamic baseline.</td><td>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.</td></tr>
</table>

Stakeholder	Stakeholder Feedback	EPWA's Response
	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.	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 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.	See responses above.

<table>
<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA’s Response</th></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="3">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:
• 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.</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>
<tr><td>Perth Energy</td><td>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.</td></tr>
</table>

Stakeholder	Stakeholder Feedback	EPWA's Response
	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.	
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 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	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 balance between penalties and incentive to provide the service for the rest of the capacity year.

Stakeholder	Stakeholder Feedback	EPWA's Response
	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.	
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.
Proposal N: Require flexible capacity holders to lodge outages relating to capability to provide flexible capacity.		

Stakeholder	Stakeholder Feedback	EPWA's Response
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 • Synergy • Perth Energy • Alinta Energy		
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.
Proposal S: Distribute collected capacity refunds to consuming participants rather than other capacity providers.		

Stakeholder	Stakeholder Feedback	EPWA's Response
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	AEMI 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 are on regulated rates. (Additional detail provided in Alinta Energy's submission.)	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 • 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

Stakeholder	Stakeholder Feedback	EPWA's Response
	• 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.)	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 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.	See response above.

Stakeholder	Stakeholder Feedback	EPWA's Response
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 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	See response above.

Stakeholder	Stakeholder Feedback	EPWA's Response
	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).	
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		

Stakeholder	Stakeholder Feedback	EPWA's Response
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.
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; • 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	See response above.

Stakeholder	Stakeholder Feedback	EPWA's Response
	• 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 customer supply risk arising from failure of new capacity to be delivered on time.	EPWA acknowledges the request and notes that Stage 1 of the RCM Review has increased the reserve margin and therefore the Reserve Capacity Target. EPWA considers that further raising the Reserve Capacity Target would be therefore unnecessary.

Stakeholder	Stakeholder Feedback	EPWA's Response
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.
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.

Stakeholder	Stakeholder Feedback	EPWA's Response
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.