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 April 2023
Time:	9:30 AM – 11:30 AM
Location:	Online, via TEAMS, or in person at EPWA.

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_03_16	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	2 min
	(b) Reserve Capacity Mechanism Review Working Group (**RCMWG**)	RCMRWG Chair	Discussion	10 min
	(c) Cost Allocation Review Working Group (**CARWG**)	**CARWG** Chair	Discussion	10 min
7	Rule Changes			
	(a) Overview of Rule Change Proposals	Chair/Secretariat	Noting	2 min
8	RCM Review Information and Consultation Paper	Chair/Secretariat	Discussion	70 min
9	Supplementary Reserve Capacity Review	Chair/Secretariat	Noting	10 min
10	General Business	Chair	Discussion	3 Min
	Next meeting: 9:30am Thursday 8 June 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.

Minutes

Meeting Title:	Market Advisory Committee (MAC)
Date:	16 March 2023
Time:	9:30am –11:39am
Location:	Energy Policy WA and Microsoft Teams

Attendees	Class	Comment
Sally McMahon	Chair	
Dean Sharafi	Australian Energy Market Operator (AEMO)	
Martin Maticka	AEMO	
Zahra Jabiri	Network Operator	
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	Until 10:35am
Adam Stephen	Market Generator	
Paul Arias	Market Generator	
Peter Huxtable	Contestable 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
Tim Robinson	Robinson Bowmaker Paul (**RBP**)	Presenter

Apologies	From	Comment
Patrick Peake	Perth Energy	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am with an Acknowledgement of Country. The Chair advised that in her role as AEMC Commissioner, she was asked to sit on the Grattan Institute Energy Reference Group. She noted that this is not a decision making group, but a reference group to test the Grattan Institute's work program and contribution to the public policy debate in relation to energy. The Chair noted that: • MAC members are to participate in the interests of the stakeholder group they represent; and • The MAC must relate its advice to the objectives of the Wholesale Energy Market (WEM).	
2	**Meeting Apologies/Attendance** The Chair noted the attendance and apologies as listed above and that Mrs Papps had advised that she would need to leave the meeting early.	
3	**Minutes of Meeting 2022_12_13** The MAC accepted the minutes of the 2 February 2023 meeting as a true and accurate record of the meeting. **Action: The MAC Secretariat to publish the minutes of the 2 February 2023 MAC meeting on the Coordinator's Website as final.**	**MAC Secretariat**
4	**Action Items** <u>Action Item 4/2023</u> Mr Sharafi confirmed that Yandin Wind Farm and Badgingarra Wind Farm had been constrained on 30 January 2023. In response to a question from Mr Arias, Ms Guzeleva clarified that: • intermittent generators are assigned CRC on the basis of what they could have generated without a curtailment; and • from the 2023 Reserve Capacity Cycle the Network Access Quantity regime will limit a Facility's Capacity Credits if AEMO's modelling under the WEM Rules indicates that the Facility will be subject to network constraints during future system peak periods. <u>Action Item 5/2023</u> Mr Sharafi noted that AEMO had activated and dispatched supplementary reserve capacity (SRC) on 30 January and 20 February 2023. Mr Sharafi noted that: • one facility had been unable to provide the contracted service. A reduction of the SRC contract quantity and refunds have been	

Item	Subject	Action
	applied for that service. As a result AEMO has a total of 73 MW of SRC remaining available or dispatch; • some facilities responded well but the response was difficult to quantify because of data issues; • some facilities had difficulties in responding because of the high temperature during the events; • the notice period of nine hours for some facilities is problematic for AEMO, because the need to dispatch SRC is difficult to predict nine hours ahead and the manual nature of the dispatch process makes a recall cumbersome for AEMO; • the variations between contracts, in terms of value, was difficult for AEMO to operationalise in the control room; and • it was the first time AEMO dispatched a commercialised virtual power plant. In regard to the procurement of SRC, Mr Sharafi noted that • finalising the contracts for some of the SRC services had been difficult because the relevant facilities needed to connect to different parts of the network, which resulted in an inefficient use of time for AEMO and Western Power; and • the greatest impediment in the process was the short procurement timeframe. Mr Sharafi noted that he would raise a possible requirement for SRC for next summer under Agenda Item 9 (General Business). In response to a question from Mr Arias, Mr Sharafi clarified that during the two events AEMO dispatched not all, but most of, SRC. Ms Guzeleva noted that EPWA recently published a Consultation Paper on the SRC procurement process. EPWA will submit Amending Rules to the Minister soon. Ms Guzeleva noted: ○ the issue of the nine hour notice period for some SRC services has been addressed in the proposed improvements in the Consultation Paper; ○ EPWA will commence stage 2 of the SRC Review, which will assess SRC performance including the issues outlined by Mr Sharafi. • Ms Jabiri noted that Western Power was looking forward to see how the process for procuring SRC can be improved.	
5	**Market Development Forward Work Program** The paper was taken as read.	
6	**Update on Working Groups**	
	(a) AEMO Procedure Change Working Group (APCWG) Mr Maticka noted that the consultation on Procedure Change Proposal AEPC_2022_02 has closed. AEMO is now assessing the feedback	

Item	Subject	Action
	received and will provide a further update to the MAC when the procedure commences.	

(b) RCM Review Working Group (RCMRWG) Update

The papers, including the presentation, for agenda item 6(b) were taken as read.

The Chair noted that MAC members are being asked to

- note the minutes from the RCMRWG meetings on 15 December 2022, 1 February and 16 February 2023;
- note the update from the RCMRWG meeting on 1 February, 16 February and 2 March 2023;
- endorse the proposed approach to:
  - the treatment of Demand Side Programmes (DSPs) in the Reserve Capacity Mechanism;
  - the determination of the Individual Reserve Capacity Requirement (IRCR) for the peak capacity product;
  - the determination of the IRCR for the flexible capacity product;
  - the implementation of a penalty for high emissions technologies; and
  - addressing the duration gap.

Ms Guzeleva noted that at the last MAC meeting members:

- indicated that they are comfortable with the proposed approach for determining the capacity value for the fleet of intermittent generators; and
- requested further analysis on the proposed approach for allocating the fleet value to individual intermittent generators.

Ms Guzeleva noted that the requested analysis had been undertaken and that the RCMRWG supports the proposed approach for allocating Certified Reserve Capacity to individual intermittent generators.

Ms Guzeleva advised the MAC that:

- this was the last time that the certification of intermittent generators would be discussed with the MAC;
- the next steps are to publish an Information Paper and a Consultation Paper as soon as practicable;
- a draft of the Consultation Paper is planned to be discussed at the 20 April MAC meeting; and
- the intent is to complete the actual RCM Review by the middle of this year, noting that some very important proposals resulting from the review must be implemented.

Mr Robinson presented the proposals and a summary of the related RCMRWG discussion. The following was discussed:

<u>DSPs</u>

Mr Robinson noted that the proposal was to use two methods for assigning Certified Reserve Capacity (CRC) to DSPs:

- Method 1: Basing the CRC on historic load – this method would be appropriate for DSPs for which the associated loads don't change from year to year and for which past consumption is a good predictor for future consumption;

- Method 2: Having the DSP proponent nominate CRC, accompanied by evidence that sufficient load is associated with the DSP – this method would be appropriate for DSPs aggregating smaller loads that change over the year and for which past consumption is not a good predictor for future consumption.

Mr Robinson noted that the proposed methods for assigning CRC to DSPs work with either static or dynamic baseline. However, a few changes to testing and refunds would be needed if a dynamic baseline was implemented (see slides 8 and 9).

Mr Robinson noted the RCMRWG's two main concerns were:

- that if DSP proponent can just nominate their CRC, this could attract providers that are not genuine (e.g. nominate 100 MW but fail to associate the required loads); and
- the potential cost for AEMO to apply two different certification methods.

Mr Robinson noted that the RCMRWG also raised more general concerns about DSPs and demand side participation, which are out of scope for the RCM Review but should be covered through the Demand Response Review, which would be discussed under agenda item eight.

Mr Robinson noted that:

- DSP providers that are not genuine should be deterred by the requirement to provide capacity security that will be forfeited in addition to any Reserve Capacity Refunds if they fail to associate the required loads; and
- the two methods are similar enough to avoid excessive cost.

In response to a question form Mr Alexander, Mr Robinson clarified that so far there had been no issues with non-genuine DSP providers. However, if an issue would occur, it would represent a risk to system reliability.

- Mr Edwards raised a concern about introducing a dynamic baseline. His experience with DSP providers that operated in jurisdictions using dynamic baselines indicated that dynamic baselines may incentivise providers to increase consumption before the dispatch time. This would result in perverse outcomes for the market and system reliability.

Mr Robinson clarified that:

  - o from the start of the new market, DSP providers will have to provide AEMO with the expected consumption of their associated loads;
  - o the dynamic baseline should be based on consumption during historical days and not the intervals leading up to the dispatch; and
  - o a static baseline is problematic for AEMO because it does not reflect the actual load reduction that AEMO will receive during a dispatch.

- Mr Huxtable expressed his preference for a static baseline and noted that AEMO could be provided with better visibility of the actual reduction through telemetry such as SCADA feeds.
- Mr Huxtable considered that loads are paying for consumption during system peak and this should be reflected in their baseline no matter what the actual load reduction was when dispatched outside of system peak.

Ms Guzeleva noted that the proposed treatment of DSPs in the Reserve Capacity Mechanism will be consulted on in the Consultation Paper.

- Ms Teo asked if it would be assessed how DSP participation could be incentivised over IRCR reduction, noting that AEMO can better rely on DSPs than IRCR reduction.

Mr Robinson noted that this question had been discussed extensively with the RCMRWG and that the main reasons why participants may prioritise IRCR reduction over participating as a DSP are that:

- the current static baseline disincentivises to provide load reduction through a DSP; and
- the Non-Temperature Dependent Load (NTDL) multipliers applied to the IRCR further increase the benefit of IRCR reduction against the capacity payments a DSP can receive.

Ms Guzeleva added that to reduce IRCR, consumers needed to target load reduction during 12 intervals while DSPs can be dispatched for up to 200 intervals. Ms Guzeleva noted that stakeholders capable of registering a DSP indicated that this incentivises reducing the IRCR over registering as a DSP.

- Mr Arias noted he was not convinced that signing up DSPs provided more benefit than loads reacting to the IRCR.
- Mrs Papps noted that she was not convinced that the changes to the treatment of DSPs provide enough benefit to warrant delaying other more complex reforms that are needed to be implemented by AEMO.
- Mr Arias agreed with Mrs Papps and considered that the outcome of the recent SRC procurement process indicated that there are not many loads willing to participate as DSPs.

Ms Guzeleva noted that the SRC procurement process was undertaken over a very short period of time making it difficult for aggregators to participate. Therefore SRC did not provide a good indication for the DSP capacity that could be secured.

- Mr Schubert considered that there are hundreds of MW of useful potential DSP capacity in the SWIS that could be attracted if the right incentives were provided.

Ms Guzeleva noted that there was an open Rule Change Proposal that would require addressing the treatment of DSPs.

The Chair noted that the MAC was asked to endorse the proposed changes to the treatment of DSPs for further consultation.

- Mr Huxtable endorsed publishing the proposal for consultation.
- Mr Schubert considered that if an operator of an industrial load incurred costs to increase the loads capability to reduce consumption compared to its historical consumption, the load should be certified for the additional capability.

In response to a question from Mr Schubert, Ms Guzeleva clarified that individual participants would not be allowed to choose between a static and dynamic baseline as that would increase implementation costs.

- Mr Gaston questioned why Reserve Capacity Refunds are paid to generators and not to customers if customers have paid for the capacity. Mr Gaston noted that this should be revisited at some point.
- Mr Stephen questioned the need to require DSPs to provide capacity security that can be drawn on in addition to the refund of capacity payments.

Mr Robinson noted the rationale for including the reserve capacity security was to disincentive non-genuine DSPs. This is because losing the capacity payments is not a sufficient threat for DSPs. Unlike a generation Facility, a DSP's business case does not rely on capacity payments and it requires less capital investment to participate.

In response to a question from the Chair, Ms Guzeleva noted that the current rules are already different for generators and DSPs and that Generators have to schedule outages with AEMO. EPWA had discussed the issue of penalties with potential DSP providers and they understand the need for financial consequences for non-performance.

Ms Guzeleva noted that if a DSP does not respond this poses a risk to system reliability. However, the proposed approach will be further consulted on.

The Chair noted that the MAC endorsed the proposed treatment of DSPs for further consultation noting that assessing the issues that have been raised and identified will be part of the consultation process. Mr Peake had provided his endorsement via email prior to the meeting.

<u>IRCR</u>

Mr Robinson presented the proposed method for selecting the intervals to determine the IRCR (slide 15).

In response to questions from Mr Stephen and Mr Edwards, Mr Robinson clarified that, for the purpose of determining the IRCR intervals, any demand reduction through dispatch of SRC or DSPs will have to be added back to the demand.

- All MAC members except for Mr Edwards supported the proposal.
- Mrs Papps and Mr Peake had provided their support via email.
- Mr Edwards expressed concerns that the proposal could select IRCR intervals from as little as three days and he considered that days where SRC is dispatched could not be included in the IRCR intervals.

Item	Subject	Action
	• Mr Schubert considered that it should be investigated how the IRCR response from customers may shift the IRCR intervals. Ms Guzeleva considered that shifting the peak would achieve the objective of the IRCR. <u>CRC for intermittent generation</u> Mr Robinson presented the analysis of the proposed method for allocating CRC to intermittent generators. Mr Robinson noted that the analysis indicated that the proposed method: • provides no obvious distortions; • it less volatile than the delta method; and • result in the year to year changes are influenced by both the fleet ELCC and Facility performance. Ms Guzeleva summarised Mrs Papps' comments which had been provided via email noting that Mrs Papps: • broadly supported the proposal; and • considered that the proposed method should be implemented as soon as possible to address the increasing issues with the current Relevant Level Methodology. The implementation should not be held up by the increasing list of reforms being implemented under this review. Ms Guzeleva noted that the capacity value of the fleet of intermittent generators is the basis for the allocation of CRC to individual intermittent generators and will change from year to year. Ms Guzeleva emphasized that the CRC values presented on slide 29 are just an illustration of how the proposed allocation method works. The Chair noted that MAC members endorsed the proposed method for assigning CRC to intermittent generators to be included as a decision in the information paper. <u>Penalties on high emission technologies</u> Mr Robinson presented a summary of the RCMRWG discussion about the implementation of a penalty for high emission technologies, the resulting final proposal and the outcomes of the relevant analysis. The proposal is to apply emission thresholds for Facilities seeking to be certified in the RCM, as follows: • for new Facilities: an emission rate threshold of 0.55 tCO_2e/MWh for the emissions per MWh produced and a quantity threshold of 1,000 tCO_2e/MW for annual emissions per MW; and • for existing Facilities: a quantity threshold of 4,000 tCO_2e/MW for annual emissions per MW that will be decreased by	

500 tCO_2e/MW each year until the threshold equals the threshold for new Facilities.

Mr Robinson noted that the thresholds and proposed commencement dates had been updated since the circulation of the papers.

Mr Robinson noted that the proposal would allow for new efficient gas Facilities to enter the market and receive CRC if they operate as peaking plants. Mr Robinson noted that the commencement of the penalty is still subject to change.

Mr Robinson noted that the analysis presented was based on the assumption that participant behaviour does not change. Further modelling is underway to assess how Facilities would likely be dispatched if the proposed regime was implemented.

- Mr Sharafi noted AEMO's concerns that the proposed thresholds could impact power system security and reliability, if the frequency of its dispatch could affect a Facility's eligibility to receive Capacity Credits.
- Mr Sharafi considered that more modelling was required to assess the impact on system security and reliability. Mr Sharafi considered that the objective should be to deter inefficient Facilities from entering the market but should allow the needed flexible Facilities to receive Capacity Credits.

In response to a question from the Chair, Ms Guzeleva noted that the Minister had confirmed that the proposed option is consistent with the intent of the policy to target high emission technologies. Ms Guzeleva noted that the proposal should be considered in the context of the other reforms proposed under the RCM Review which included a flexible capacity product to attract the needed flexible Facilities.

The Chair asked if analysis had been undertaken that identified the Facilities expected to enter the market if high emission Facilities are excluded.

Ms Guzeleva clarified that AEMO must acquire sufficient Capacity Credits each year to meet the Reserve Capacity Requirement. The Facilities providing the Capacity Credits would have to meet the new emission thresholds and the introduction of the flexible capacity product would ensure sufficient flexible capacity is provided.

Ms Guzeleva noted that any modelling would show that the needed capacity to replace retiring high emission Facilities would be provided by storage and renewable generation. This is because new coal plants would not be able to receive Capacity Credits and gas Facilities will only be able to receive Capacity Credits if they are dispatched for no more than 20% of the intervals in a year.

Ms Guzeleva noted that the current proposal was to apply the penalty from the 2028 Reserve Capacity Cycle so it would affect Capacity Credits for the 2030 Capacity Year.

- Ms Jabiri considered that the penalty regime should allow for the exemption of Facilities to avoid risk to system security and reliability.

Ms Guzeleva noted that the proposal would be subject to consultation. Ms Guzeleva noted that EPWA was not going to recommend to the

Minister to implement a proposal that would compromises system reliability.

Ms Guzeleva noted that the advantage of the proposed option is that it provides certainty about when the need for Capacity Credits from low emission Facilities to meet the Reserve Capacity Requirement emerges, which would support system reliability.

- Mr Alexander noted that the Expert Consumer Panel supported the proposal as it is important to embed emission reduction objectives in the WEM Rules. Mr Alexander would be concerned if new fossil fuel generation is allowed into the WEM.
- Mr Alexander noted that other measures should be taken to support system reliability such as incentivising demand response and energy efficiency.

In response to a question from Ms Teo, Mr Robinson clarified that for the modelling it was not assumed that any new gas fired Facilities would enter the WEM.

Ms Guzeleva noted that Mrs Papps had provided comments via email that would be included in the minutes. The comments were as follows:

> *"While we support the proposal for the scheme to constitute a threshold for participation. We continue to maintain our opposition expressed in the RCMWG that a quantity threshold should not be applied to either new entrants or existing plant, echoing the comments made and supported by numerous RCMWG members that this would:*
>
> - *create an unacceptable risk to investors and existing plant noting that they could be forced to retire an otherwise relatively low emissions plant where they were simply required to run more often to support reliability than anticipated;*
> - *favour smaller, higher more expensive equipment that won't run often, increasing costs and total emissions;*
> - *contradict incentives to be available; and*
> - *not deliver any benefits in addition to the intensity threshold.*
>
> *We continue to note the need for these thresholds to consider what the capacity mix could feasibly be. Our view, consistent with Grattan and ERA's modelling is that flexible gas Facilities with offsets will be required, especially noting the extreme costs and reliability risks highlighted by ERA of going decarbonising the last 20% of emissions and the lack of hydro opportunity in WA.*
>
> *We note the strong requirements already dissuading high emissions investment, including the WA EPA guideline which is planned to be implemented in July 2023 and would require new Facilities to make "deep and substantial emissions reductions this decade and achievement of net zero emissions no later than 2050 along a linear trajectory (at a minimum) from 2030"."*

Ms Guzeleva noted that, in her email, Mrs Papps recommended:

- if a threshold is applied to existing Facilities, it should be based on emissions rate threshold and not a quantity threshold;

- the threshold requires further consultation as part of the consultation paper.

Ms Guzeleva noted that the penalty for high emission technologies would be subject to further consultation. However, for existing Facilities a quantity threshold must be applied because these Facilities cannot change their inherent emissions rate threshold and, therefore, this would not provide them with an incentive to reduce emissions.

The Chair read Mr Peake's comments provided via email prior to the meeting.

- Mr Peak endorsed the proposal outlined on slide 40. However, Mr Peake did not endorse the proposed implementation dates because he considered that:
  - more modelling is required on the resulting requirements for new generation; and
  - substantial new capacity will be required over the next few years and it is questionable whether this can all be financed, built and connected to the grid quickly enough to satisfy peak demand and energy supply requirements.
- Mr Gaston did not endorse the proposal. He considered that the proposal would erode system reliability, increase electricity costs and lead to closure of industry. Mr Gaston noted that he disagreed with the policy decision to target emissions through the RCM.
- Mr Stephens noted that Facility operators may decide not to bid into the market to reduce emissions. However, Facilities could still be dispatched and exceed the threshold if needed by the market resulting in exits of capacity that may be difficult to replace in the available time.

Ms Guzeleva noted that the proposal was to align the commencement of the penalty with the Government's plans to retire its coal Facilities. Ms Guzeleva noted that two conflicting views have been expressed that will be consulted further:

- View 1: investment in new fossil fuel Facilities will be required; and
- View 2: no new fossil fuel Facilities should be allowed in the SWIS.

The Chair acknowledged that further work needs to be undertaken to understand how retiring Facilities will be replaced and how investment will be incentivised. However, the proposed scheme provides some certainty about the pathway to achieving emission targets.

The Chair noted that members were questioning whether it is appropriate to address emissions through the RCM. However, this will be a decision made by the Minister.

Ms Guzeleva noted that emission thresholds for participating in capacity mechanisms are applied in other jurisdictions.

- Mr Arias noted that the proposal was difficult to support because it represents a sovereign risk.

The Chair noted that the National Government generally accepted that fossil fuels need to be removed from the electricity market to achieve emission reduction targets. Investors were making decisions based on the expectation that there would be emissions reductions and that policies to achieve this are forthcoming.

- Mr Arias noted that the threshold is specifically targeting Bluewaters Power Station to exit the market in 2032, as it is the only coal plant left after the retirement of the Government's coal plants. Mr Arias noted that Bluewaters Power Station is currently needed in the WEM.

Ms Guzeleva noted that it could not be expected to achieve the emission reduction targets while customers are continuing to pay for high emission Facilities in the RCM.

- Mr Stephens suggested that coal plants may retire naturally if wholesale electricity prices continue to decrease.

The Chair noted that the energy industry has been requesting that the Government aligns energy policy with emission reduction policies for years. Most investors would expect that future energy policy will address emissions. Therefore, aligning energy policy with emission reduction policy is more likely to reduce investment uncertainty.

Ms Guzeleva noted that EPWA was in the process of drafting legislation to change the Energy Market Objectives to an objective similar to the one in the National Energy Market. The new objective would pertain to price, reliability and emissions. Therefore, Ms Guzeleva considered that the proposed penalties would not represent a sovereign risk.

- Mr Schubert considered that the SWIS demand assessment would show that even more new capacity will be required to enable the expected electrification.
- Mr Alexander considered that it should be accepted that emissions will be addressed in the RCM and the discussions should be about the specifics of the penalty regime.

Ms Guzeleva noted that the proposed new flexibility product for flexible generation with low minimum generation and high ramp rates should provide incentives for flexible Facilities to fill the gap left by high emission Facilities that don't receive Capacity Credits. However, if high emission Facilities keep receiving Capacity Credits there won't be sufficient incentives for new Facilities.

The majority of the MAC endorsed in principle the proposed method for implementing a penalty for high emission technologies but noted concerns around the timing and the impact on security and reliability of the system if other reforms do not provide the needed incentives.

The Chair noted that further modelling was implicit because it would be needed to inform the Minister's decision.

<u>Duration Gap</u>

Mr Robinson summarised the proposal for addressing the duration gap. The proposal is to implement:

  - the design of different capability classes as proposed in the Stage 1 Consultation Paper;

Item	Subject	Action
	○ mechanisms to monitor the need for addressing the duration gap more directly. • Ms Teo considered that the duration gap was a current issue but that it was hidden by obligations, such as the 14 hour fuel requirement, that apply to certain Facilities. Those obligations pose risks on the affected Facilities that are not recognised in the RCM. • Ms Teo considered that the Facilities that currently cover the duration gap should be reasonably compensated for it and that the issue should be addressed now and not in later reviews. Ms Guzeleva noted that the Synergy representative on the RCMRWG had argued that Facilities to which the 14 hour fuel requirement applies should receive additional compensation, but this had not been supported by the RCMRWG. However, Synergy's concern would be documented in the Stage 2 Consultation Paper. <u>Flexible Capacity IRCR</u> Mr Robinson summarised the proposed method for determining the flexible IRCR intervals and noted that the slides show which intervals would be selected under this method. Mr Robinson noted that the RCMRWG supported the proposed approach. Ms Guzeleva noted that the RCMRWG will hold another meeting to discuss the design of the flexibility product. The outcome will be reflected in the Stage 2 Consultation Paper which will be discussed at the 20 April MAC meeting. • Mr Sharafi noted AEMO's support for the proposal subject to the detailed design.	
7	**Rule Changes** **(a) Overview of Rule Change Proposals** The paper was taken as read. There were no updates.	
8	**Terms of Reference for a Demand Side Response Review Working Group** The paper was taken as read and endorsed by the MAC.	
9	**General Business** **2023 SRC** Mr Sharafi noted that it was very likely that AEMO will need to procure SRC for the 2023 Capacity Year. **Transparency of changes to the power system** Mr Sharafi noted that the energy transition had resulted in many changes to the power system and that these changes are not transparent and only known to limited personnel at Western Power and AEMO. AEMO had identified a risk that the information may be	

Item	Subject	Action
	lost if those experts left their organisations. Therefore, information about the elements of the power system, such as impedances of lines and transformers and characteristics of generation Facilities, should be published so stakeholders could build their own models of the power system. The Chair thanked Mr Sharafi for raising the issue and noted that this subject would require further consideration. The next MAC meeting is scheduled for 20 April 2023.	

The meeting closed at 11:39am.

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_04_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
6/2023	MAC Secretariat to publish the minutes of the 2 February 2023 MAC meeting on the Coordinator's Website as final.	MAC Secretariat	2023_03_16	**Closed** The minutes were published on the Coordinator's Website on 16 March 2023.
4/2023	AEMO to confirm whether the Yandin and Badgingarra wind farms were constrained on 30 January 2023.	AEMO	2023_02_02	**Closed** At the MAC meeting on 16 March 2023, AEMO confirmed that both wind farms had been constrained.
5/2023	AEMO to provide an update on any learning to be shared from activating SRC on 30 January 2023.	AEMO	2023_02_02	**Closed** AEMO provided an update at the MAC meeting on 16 March 2023

Agenda Item 5: Market Development Forward Work Program

Market Advisory Committee (**MAC**) Meeting 2023_04_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 Table 1, including:
  - 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 since the last MAC meeting – see Agenda Item 6(b).
  - the Chair of the Cost Allocation Review Working Group (**CARRWG**) is to update the MAC on the progress of the Cost Allocation Review (**CAR**) Review since the last MAC meeting – see Agenda Item 6(c).
  - to provide an update on other issues to be addressed via the Market Development Forward Work Program provided in Table 4:

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: ○ the Terms of RCMRWG, as approved by the MAC; ○ the list of RCMRWG members; ○ 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 and 24 November 2022; 15 December 2022 and 1 February 2023, 16 February 2023 and 2 March 2023; and ○ meeting papers from the RCMRWG meeting on 22 March 2023. • The Chair of the RCMRWG will update the MAC on the progress of the RCM Review since the last MAC meeting, including EPWA's draft Information and Consultation Paper – see Agenda Item 8. • 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: ○ the Scope of Works for the review, as approved by the Coordinator; ○ the Stage 1 Consultation Paper; ○ the Paper on the Review of International Capacity Mechanisms; and ○ submissions on the Stage 1 Consultation Paper.

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: ○ the Scope of Work for the review, as approved by the Coordinator; ○ the Terms of Reference for the CARWG, as approved by the MAC; ○ the list of CARWG members; ○ the Consultation Paper; ○ the International Review; ○ submissions on the Consultation Paper; ○ 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 15 December 2022; and ○ meeting papers from the CARWG meeting on 21 March 2023. ○ The Chair of the CARWG will update the MAC on the progress on the CAR since the last MAC meeting
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.	• A Scope of Work for this review was brought to the MAC at its meeting on 16 March 2023. MAC members were asked to endorse the Scope of Works at that meeting. • 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: ○ the Scope of Work for the review, as approved by the Coordinator; and ○ the Terms of Reference for the DSRRWG, as approved by the MAC. • A call for nominations for the working group for the Demand Side Response was published 27 March 2023. The nomination period closes on 12 April 2023. • Following a competitive process, the Coordinator has appointed The Lantau Group to assist with the DSR Review.

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?	To be considered in the Cost Allocation Review.
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.	To be considered in the Cost Allocation Review.
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	To be considered in the Cost Allocation Review.

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
		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.	
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 available. There needs to be equity in this equation.	To be considered in the Cost Allocation Review.

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 April 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	17 January 2023	06 June 2023 (tentative)
WEM Procedures for discussion	WEM Procedure: DER Information Register	WEM Procedure: Supplementary Reserve Capacity

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 20 April 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
AEPC_2022_02	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

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

Market Advisory Committee (MAC) Meeting 2023_04_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 minutes from the RCMRWG meeting on 2 March 2023 (**Attachment 1**);

(2) the update from the RCMRWG meeting on 22 March 2023; and

(3) that the outcomes of the RCMRWG and MAC meetings to date are reflected in the Reserve Capacity Mechanism – Information and Consultation Paper that is tabled for discussion under Agenda Item 8.

3. Process

- On 22 March 2023, the RCMRWG discussed:
    - details of the flexibility product including proposals for:
        - certification of facilities to provide flexible capacity;
        - obligations for holders of flexible capacity credits and testing of those obligations;
        - amendments to the outage regime to account for flexible capacity; and
        - the approach to refunds for failure to meet those obligations.
    - further analysis for the implementation of a penalty on high emission technologies and revised proposals for penalties for new and existing facilities,
    - amendments to outage and refund rules, including:
        - DSPs; and
        - incorporating the new flexible capacity product.
- Papers for the RCMRWG meeting on 22 March 2023 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 is available on the RCM Review webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review

4. Attachments

(1) Minutes of RCMRWG Meeting on 2 March 2023

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	2 March 2023
Time:	9:30 AM to 11:30 AM
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Manus Higgins	AEMO	
Toby Price	AEMO	Subject matter expert
Oscar Carlberg	Alinta Energy	
Kiran Ranbir	ATCO Australia	
Daniel Kurz	SSCP Power	
Geoff Gaston	Change Energy	Subject matter expert
Andrew Stephens	Clear Energy Pty Ltd	
Jake Flynn	Collgar Wind Farm	
Matt Shahnazari	Economic Regulation Authority	
Owen Cameron	Enel X	Subject matter expert
Scott Cornish	Enel X	Subject matter expert
Dale Waterson	Merredin Energy	
Patrick Peake	Perth Energy	
Tessa Liddelow	Shell Energy	
Paul Arias	Shell Energy	From 10:15
Noel Schubert	Small-Use Consumer representative	
Andrew Walker	South32 (Worsley Alumina)	
Rhiannon Bedola	Synergy	
Dev Tayal	Tesla Energy	
Peter Huxtable	Water Corporation	
Mark McKinnon	Western Power	
Tim Robinson	Robinson Bowmaker Paul (**RBP**)	
Ajith Sreenivasan	RBP	
Shelley Worthington	EPWA (**EPWA**)	
Laura Koziol	EPWA	
Stephen Eliot	EPWA	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Minute of RCMRWG meeting 2023_02_16** The draft minutes of the RCMRWG meeting held on 16 February 2023 2022 were distributed on 27 February 2023. Mrs Bedola requested the following change to the minutes on page four to reflect what she said at the meeting: • Mrs Bedola considered that AEMO can rely less on loads to react to the IRCR signal than on a DSP that must respond to a dispatch instruction. If AEMO reduces its forecast demand because a load previously reduced consumption in response to the IRCR signal and the load does not react to the IRCR signal the next time this may cause issues for system reliability. The RCMRWG accepted the minutes, as proposed to be amended, as a true and accurate record of the meeting.	
	Action: RCMRWG Secretariat to publish the minutes of the 16 February 2023 RCMRWG meeting on the RCMRWG web page as final.	**RCMRWG Secretariat**
4	**Action Items** The paper was taken as read.	
5	**Penalties on High Emission Technologies** Mr Robinson presented the proposed option for the implementation of a penalty for high emission technologies. The Proposal is to apply emission thresholds for facilities seeking to be certified in the RCM: • for new facilities: an emission rate threshold for the emissions per MWh produced and a quantity threshold for annual emissions per MW; and • for existing facilities: a quantity threshold for annual emissions per MW. The following was discussed: • Mr Kurz noted that his concerns raised in the previous RCMRWG meetings regarding the introduction of a penalty excluding high emitting facilities from participation in the RCM remain. • Mr Schubert noted that the Merredin Gas Turbine and the Kalgoorlie Gas Turbine Power Station, which are listed as gas generators on slide11, are facilities that only run on distillate.	

Item	Subject	Action

	Mr Robinson acknowledged that this is the case and noted that the chart is only for illustration. The actual emission rate and annual emissions will reflect the actual values for the facilities.
	The Chair clarified that a formula reflecting the expected fuel mix would need to be applied to assess new dual fuel facilities.
	• Mr Peake considered that a new combined cycle gas facility can't be financed if it is only allowed to be dispatched for 30% of the Trading Intervals in a Capacity Year.
	• Mr Carlberg agreed with Mr Peake.
	In response to a question from Mrs Bedola, Mr Robinson clarified that the threshold for new facilities is proposed to be stable and not change. However, it is possible that a future reform could reduce the thresholds.
	• Mrs Bedola considered that new facilities should be protected from changes to the threshold for a set period of time after they enter the market.
	The Chair agreed that such a protection should be included.
	In Response to a question from Mr Price, Mr Robinson noted that, if a Facility exceeded the annual emission threshold, because it had to be dispatched to maintain system reliability, it would still not be eligible for Capacity Credits in the next Capacity Cycle.
	• Mrs Bedola considered that the annual threshold needs to be considered when assessing outages and refunds when a Market Participant does not want to offer its facility to avoid reaching the threshold.
	• Mr Peake considered that the following needs to be modelled for the next 10 years to ensure that the proposed penalty allows the market to meet the new state electricity objective:
	  ○ can the capacity needed to replace the retiring facilities and maintain system security and reliability be built;
	  ○ can the needed capacity be funded;
	  ○ can Western Power provide the needed network capacity; and
	  ○ are there any implications for the gas transmission system.
	The Chair agreed that whether the needed capacity can be built and funded should be modelled. However, modelling Western' Power's Network and the gas transmission network is not within the scope of the RCM Review.
	Mr Robinson noted that the economic modelling will assess whether the needed new facilities are financially viable.
	• Mr Kurz considered that:
	  ○ the role of the RCM is to remunerate facilities to be available independent of the actual generation. Carbon taxes usually work because they directly penalize the emissions. Therefore, the proposed penalty is not aligned with the role of the RCM.	

Item	Subject	Action
	○ new renewable facilities are hindered form entering the market by a lack of network access and not by the existence of high emitting facilities. ○ the Gas Statement of Opportunities (GSOO) indicates that the retiring facilities cannot fully be replaced by gas fired facilities. • Mr Kurz considered that the RCM is not the right place to implement a penalty on high emission technologies. • Mr Schubert and Mr Waterson agreed with Mr Kurz. • Mr Higgins asked whether options would be considered for a Market Participant to remedy breaching the threshold through buying carbon offset certificates. The Chair noted that the option to incorporate carbon offset certificates had been considered in previous RCMRWG meetings and was found impracticable. • Mr Price considered that the proposal incentivises Market Participants to not dispatch their facilities when needed to avoid losing the revenue stream from the RCM. This can risk system reliability. • Mr Kurz considered that, as facilities retire, the remaining facilities will need to be dispatched more. Therefore, the more a facility is needed, the more likely it will breach the annual emission threshold. • Mr Calberg questioned whether an annual threshold should be implemented at all. He considered that the proposed option could lead to a lower cost Facility not being offered into the market to avoid breaching the annual threshold. The Chair noted that the proposed option is the preferred option because: ○ it is already applied in other markets (UK, EU); ○ it aligns with the emission objectives; ○ it provides certainty about when capacity from high emitting facilities must be replaced, which will help to address emission reduction while ensuring system reliability. • Mrs Bedola and Mr Price expressed general support for the proposed option. The Chair noted that the commencement and staging of the thresholds will be important to ensure system reliability is not at risk. • Mr Peake noted that if the emission rate threshold is set to allow for a new gas fired peaking facility to enter the market, some margin needs to be applied because the actual emissions will depend on how the facility is dispatched. • Mr Carberg agreed with Mr Peake. The Chair agreed that such a margin should be considered.	
6	**Flexible Capacity – Additional Considerations**	

Item	Subject	Action
	Mr Robinson provided a brief overview of the intervals that would be used to determine the flexible Individual Reserve Capacity Requirements under the proposed method. The slides were taken as read.	
7	**Revisiting the Duration Gap** Mr Robinson presented the proposed options to address the duration gap. The proposed options are: • Option 1: address the duration gap through the availability requirements for the proposed availability class 2; • Option2: separate the duration requirement into several parts and select availability class 2 facilities with varying availabilities to fill the requirement; and • Option 3: introduce a new capacity product to account for the duration gap. The following was discussed: • Dr Shahnazari considered that Option 2 would likely lead to cherry picking and assign different requirements to different resources. Instead, a price signal should be provided that would attract the right resources to cover the duration gap. Dr Shahnazari considered that an additional capacity product, as proposed under option 3, would likely overlap with the peak product. • Mr Carlberg agreed with Dr Shahnazari and noted that he was against introducing an additional capacity product to address the duration gap. He considered that the product should not be implemented before the actual need arises. He questioned if the need could be fulfilled as needed using a similar mechanism as the Non-Co-optimised Essential System Services (NCESS). • Mr Kurz agreed that the duration gap does not require immediate action but should be addressed in the medium-term. • Mr Price considered that the duration gap appeared to be not a problem of capacity but a supply risk. He considered that there likely is a need for an additional product but questioned whether focusing on the hours after the peak intervals is the right approach. Mr Robinson noted that a different product could be considered. • Mr Schubert considered that the duration gap is an energy issue and not a capacity issue. • Mrs Bedola considered that the duration gap is an issue for the RCM, as currently the Facilities subject to the 14 hour fuel obligation are covering the duration gap without being fairly compensated. The Chair noted that the objective is to implement the right incentives for the needed capabilities.	

Item	Subject	Action
	• Mr Carlberg considered that in a market as small as the WEM, fewer signals will drive investment and additional incentives may just become noise. Mr Carlberg considered that longer availability of storage requires additional compensation which could be achieved through an NCESS process. • Mr Peake supported Option 2 because it would allow AEMO to fill the exact need. However, Facilities with different availability duration would require different compensation.	
8	**Outages** The Slide was taken as read.	
9	**Next Steps** The Chair noted that the following items will be taken to the MAC: • discussion about IRCR and DSPs form the previous meeting; • discussion about the penalties for high emission technologies; • discussion about the duration gap; and • the next level of detail about the flexibility product, noting that there was no consensus on the items discussed today. However, there was general consensus that: • the implementation of emission thresholds is the preferred option for the penalties for high emission technologies; and • the duration gap is a real issue but should be addressed at a later point in time.	

9	**General Business**
	Basing part of the IRCR on average consumption and not consumption during system peak
	• Mrs Bedola noted that all customers receive reliability for 24 hours every day but pay for Capacity Credits based on their consumption share during peak demand periods captured by the IRCR. Mrs Bedola considered that customers should pay a share of the cost of Capacity Credits based on their average demand and another share based on their contribution to peak demand. This would mean:
	    ○ customers would pay for capacity covering the duration gap and reliability during the entire year as well as for their contribution to peak demand; and
	    ○ customers would not avoid paying for capacity by reducing their consumption during the IRCR intervals.
	• Mr Schubert considered that the question is whether a load that does not consume during peak demand contributes to the Reserve Capacity Requirement.
	• Mr Carlberg considered that including a base load consumption element into the IRCR would dilute the signal to reduce	

Item	Subject	Action
	consumption during peak demand. Mr Carlberg also considered that the issue raised by Mrs Bedola should not be prioritised because the proposed method change may not result in a substantial change to the payments by participants. • Dr Shahnazari considered that the determination of the IRCR should be aligned with the method for assigning Certified Reserve Capacity. • Mr Cornish considered that the purpose of the RCM is to ensure there is sufficient capacity to cover peak load. The SWIS is a system with extreme peaks so the capacity needed to cover the top portion of these extreme peaks is not dispatched enough to justify the investment based on the energy market only. If this wasn't the case, the RCM would not be needed. • Mrs Bedola noted that generation facilities have obligations to be available 24 hours every day. The Chair noted that the reason generators have to be available outside of peak periods is to allow for effective scheduling of Outages. • Mr Price agreed with Mr Carlberg and Mr Cornish that basing the IRCR on consumption during peak demand is currently appropriate because the IRCR should align with the setting of the Reserve Capacity Requirement. However, in future providing capacity outside of peak demand may become more relevant to the Reserve Capacity Requirement and the method for setting the IRCR may need to include an appropriate metric to account for this. **Incentives for Load Shifting** The Chair considered that it should be discussed how to reward shifting of load from the evening peak to the middle of the day. • Mr Schubert considered that load shifting should be incentivised by retail tariffs. **The Chair noted that tariffs are out of scope for the RCM Review.** • Mr Carlberg considered that load shifting should not be part of the scope of the RCM. • Mr Schubert considered that there are opportunities to shift load that are currently not realised and that the Coordinator's upcoming Demand Side Response Review could address the issue. • Mr Huxtable considered that the WEM price signals are not strong enough to incentivise load shifting and that other options to incentivise load shifting should be investigated. • Ms Ranbir supported the investigation of options to incentivise flexible loads through the RCM. • Mr Cornish agreed that options for incentivising load shifting should be investigated. He noted that ENEL-X has recently started to offer a flexible retail contract in the NEM for loads that can shift their	

Item	Subject	Action
	consumption. However, the price signal in the WEM is not sufficient to incentivise load shifting. • Mrs Bedola considered that the IRCR provides sufficient signal to shift load. The Chair noted that the IRCR provides an incentive to shift load from the peak but no incentive for shifting it to midday. • Mrs Bedola considered that this signal should be set by the retailers. • Mr Peake questioned whether there are sufficient loads that could shift their load but currently don't to justify a change to the RCM.	

The meeting closed at 11:30 am

Agenda Item 6(c): Update on the Cost Allocation Review Working Group

Market Advisory Committee (MAC) Meeting 2023_04_20

1. Purpose

The Chair of the Cost Allocation Review Working Group (CARWG) is to provide an update on the activities of the CARWG since the last update to the MAC (13 December 2022).

2. Recommendation

That the MAC:

(1) note the draft minutes from the CARWG meeting on 21 March 2023 (**Attachment 1**); and

(2) advise whether it has any concerns with the draft recommendations for the Cost Allocation Review that have not already been discussed by the CARWG.

3. Background

- Energy Policy WA (EPWA) published the Cost Allocation Review Consultation Paper on 15 December 2023.
- Submissions on the Consultation Paper closed on 9 February 2023. EPWA received:
  - five submissions from AEMO, the Australian Energy Council, Perth Energy, the Expert Consumer Panel and Synergy; and
  - two late submissions from Alinta Energy and Shell.
- The Consultation Paper and all submissions are available on the Cost Allocation Review webpage (https://www.wa.gov.au/government/document-collections/cost-allocation-review).
- The submissions generally supported the draft recommendations from the review but raised some issues, consistent with the views previously raised by the CARWG and MAC.
- EPWA considered the submissions and the CARWG met on 21 March 2023 to discuss:
  - potential amendments to the proposed WEM Deviation Method to allocate Frequency Regulation costs;
  - treatment of multiple dispatchable units under the Runway Method to allocate Contingency Reserve Raise costs;
  - potential amendments to the proposed approach to apply the Runway Method to allocate Contingency Reserve Lower costs; and
  - the allocation of Market Fees to battery energy storage systems.

- Papers for the CARWG meeting on 21 March 2023 are available on the CARWG webpage (https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group) and draft minutes for the meeting are attached (**Attachment 1**).[1]
- EPWA and AEMO met on 31 March 2023 to discuss the concerns raised by the CARWG on 21 March 2023 and are continuing to discuss these matters by email.
- EPWA will consider how it would like to proceed with the outstanding issues for the Cost Allocation Review and will call a final CARWG meeting in mid-April 2023 to discuss these matters.

4. Next Steps

Step	Timing
(1) Final CARWG meeting	Mid-April 2023
(2) EPWA to table at the MAC: ○ a draft Information Paper indicating the final recommendations from the Cost Allocation Review (provided for information purposes) ○ draft Amending Rules to reflect the recommendations Information Paper (provided for comment)	8 June 2023
(3) EPWA to publish the Information Paper and draft Amending Rule	29 June 2023
(4) Submissions close on the draft Amending Rules.	27 July 2023
(5) EPWA to seek Ministerial approval for Amending Rules	August 2023
(6) Commencement of the Amending Rules	TBD (consistent with timing for commencement of five minute settlement)

5. Attachments

(1) CARWG 2023_03_21 – Draft Minutes of Meeting

[1] The draft minutes of the CARWG meeting on 21 March 2023 were distributed to the CARWG for review on 11 April 2023, but have not yet been approved by the CARWG and are not yet published.

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

Minutes

Meeting Title:	Cost Allocation Review Working Group (CARWG)
Date:	21 March 2023
Time:	1:00pm – 3:05pm
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Oscar Carlberg	Alinta Energy	
Daniel Kurz	Summit Southern Cross Power	
Jake Flynn	Collgar Wind Farm	
Noel Schubert	Small-Use Consumer Representative	
Mark McKinnon	Western Power	
Genevieve Teo	Synergy	
Paul Arias	Shell Energy	
Donna Todesco	AEMO	
Tessa Liddelow	Shell	
Cameron Parrotte	Woodside	
Toby Price	AEMO	Observer
Tom Geiser	Neoen	Observer
Nathan Ling	Neoen	Observer
Grant Draper	Marsden Jacob Associates (MJA)	Presenter
Peter McKenzie	MJA	Presenter
Stephen Eliot	Energy Policy WA (EPWA)	
Shelley Worthington	EPWA	

Apologies	From	Comment
Jason Froud	Synergy	
Tom Frood	Bright Energy	

Item	Subject	Action
1	**Welcome and Agenda** The Chair opened the meeting at 1:00pm.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above. The Chair noted the competition law obligations of CARWG members.	
3	**Minutes of CARWG Meeting 2022_11_29** The minutes of the CARWG meeting held on 29 November 2022 were accepted as a true and accurate record of the meeting. **Action: The CARWG Secretariat is to publish the minutes of the 29 November 2023 CARWG meeting on the Coordinator's website as final.**	**CARWG Secretariat**
4	**Action Items:** The Chair noted that there were no open action items.	
5	**Timeline and Purpose** Mr Draper noted where the project is on its timeline and indicated that the purpose of the meeting was to get agreement on the recommendations so that the project could move to the detailed design phase.	
6	**Feedback from the Consultation Process and Potential Refinements of Methods**	
	(a) Frequency Regulation – WEM Deviation Method Mr Draper noted that EPWA had received substantial feedback on the allocation of Frequency Regulation costs, particularly from AEMO. Mr Draper noted that Alinta and Synergy have raised concerns that the proposed method to allocate Frequency Regulation costs does not address the contribution of behind the meter photovoltaic (PV) to frequency deviations. • Mr Carlberg indicated that Alinta's main concern is that a cost-benefit analysis has not been done to determine that the proposed WEM Deviation Method will have a net benefit. Ms Guzeleva indicated that AEMO published an update in September 2021 indicating that one of the top priorities should be for Market Participants to receive signals that reflect their contribution to frequency response costs and that, if Market Participants are not given an incentive to improve performance, then Essential System Services (ESS) costs will increase significantly. • Mr Price agreed with this point.	

Item	Subject	Action
	Ms Guzeleva indicated that there is already evidence of increases in ESS costs and asked if a cost-benefit analysis is really necessary. • Mr Carlberg suggested that a cost-benefit analysis is necessary if we are considering a two-step process to first use the WEM Deviation Method and then switch to the new NEM Causer Pays Method at a later date. • Mr Carlberg asked if Semi-Scheduled Facilities will be able to improve forecasting or if we can just get AEMO to do the forecasting. Mr Draper outlined two options for refining the WEM Deviation Method: 1. measure deviations from linear dispatch targets over 30-minute Trading Intervals (not average of deviation from linear dispatch targets over 5-minute intervals for each 30-minute period, as previously proposed); and 2. use Balancing Market submissions for Semi-Scheduled Generation as the forecast for start and end points for each 30-minute period and measure deviations from a linear dispatch target. Mr Draper noted the pros and cons of the options and Mr McKenzie presented some modelling results for these options. Mr Draper outlined the three options for calculating contribution factors under the WEM Deviation Method: 1. Standard Deviation Method – use the standard deviation from the target in a 30-minute period; 2. Summation Method – use the sum of the absolute value of deviations from the target in a 30-minute period; and 3. Maximum Absolute Deviation Method – use the single highest absolute value of deviation from the target in the 30-minute period Mr McKenzie outlined the modelling results for these options. Mr Draper indicated that the current recommendation was to use the WEM Deviation Method, using historic SCADA data to set the hypothetic linear target for a 30-minute period, and using the Summation Method to calculate the contribution factors. In response to a question from Mr Price, Ms Guzeleva reminded the CARWG that this method would only apply for Semi-Scheduled Generators, not Scheduled Generators. • Mr Carlberg asked what a Market Participant can do to minimise variations.	

Item	Subject	Action
	Ms Guzeleva indicated that the Cost Allocation Review is about allocating Frequency Regulation costs as a means to reduce volatility, not targeting improved forecasts. • Mr Carlberg asked if we will see installation of batteries at intermittent generator sites to reduce Frequency Regulation if the cost of putting the battery in that location is lower than the cost of Frequency Regulation. Ms Guzeleva asked if we also want to provide incentives for improved forecasts. • Mr Carlberg suggested that using the previous interval may be the best forecast that Market Participants can do, in which case it may be better to give AEMO responsibility for forecasting using this method. Ms Guzeleva indicated that there appears to be three options on how to proceed, as follows, and that EPWA, AEMO and MJA should meet to discuss the options: 1. use the WEM Deviation Method, as modified in the slides presented on 21 March 2023; 2. use the WEM Deviation Method using Balancing Market submissions to set the linear dispatch target for Semi-Scheduled Generation; or 3. continue with the current cost allocation method and reconsider the new NEM Causer Pays Method after it has been implemented in the NEM. **ACTION: EPWA, AEMO and MJA to meet to discuss the options for allocating Frequency Regulation costs.**	**EPWA, AEMO and MJA**
	(b) Contingency Reserve Lower – Potential Changes to the Proposed Allocation Methodology Mr Draper noted that there is agreement that large new loads in the SWIS will have a significant impact on Contingency Reserve Lower requirements and that the cost allocation method needs to account for this impact. • Mr Geiser raised concerns with the proposed threshold and suggested that it would be fairer to apply the Runway Method to loads above 150 MW rather than 120 MW. Mr Draper noted that increasing the threshold to 150 MW only made a small difference, reducing the allocation for large (250 MW) battery energy storage system (BESS) from 48.7% to 44.1%. • Mr Geiser noted that Neoen's concern was not only with the threshold, but also with the methodology, because changing the threshold made little difference as the Runway Method: ○ assigns most of the costs to the largest load;	

Item	Subject	Action
	○ incentivises the largest load to consume less than the next largest; and ○ incentivises assets to operate less efficiently to avoid costs. • Mr Geiser noted that Neoen's proposal was intended to spread the costs around, reducing the intensity of the Runway Method for larger loads. • Mr Geiser noted that there would always be a requirement for a contingency regardless of the size of loads because a transmission line can trip, and suggested that all Contingency Reserve Lower costs should be allocated pro-rata above 100 MW to smooth out costs, with the end result being that the biggest load pays the most and therefore has an incentive to be smaller. • Mr Geiser noted that there are efficiency benefits to having 200 MW loads and it is not efficient to encourage investment in, for example, aluminum smelters in 99 MW blocks, simply to avoid paying costs. Mr Draper noted that lowering the threshold would smooth out costs, with more of the costs attributed to other loads across the system, and noted that the Runway Method is used to allocate costs for Contingency Reserve Raise services. Mr Draper noted that it is appropriate for the largest generators to pay the most Contingency Reserve Raise cots and for the same principle to apply to loads. • Mr Geiser indicated that he has the same concerns with Contingency Reserve Raise, noting that if Neoen were to build a 250 MW battery and the largest other generator is 200 MW, then they would bid below the other generator to avoid costs. • Mr Eliot noted that what Mr Geiser had requested was what was modelled and presented in the slides. • Mr Geiser disagreed, noting that the largest unit in his proposal might carry about 27% of the cost rather than 50%, with more costs distributed to smaller units because there is some minimum amount of contingency that is required no matter what. Mr Geiser noted that slide 28 was not represented in the way that he proposed. Mr Draper noted that, under Mr Geiser's proposal, smaller loads would get a much higher share of costs to smooth out cost for larger load. • Mr Geiser noted that his proposal shifted costs but that it did not resolve the problem created by the binary threshold. Ms Guzeleva noted that it was clear from the discussion that storage proponents would find it uncomfortable to wear most of	

Item	Subject	Action

the Contingency Reserve Lower costs simply because they happen to be the largest load on the system. Ms Guzeleva noted that the Runway Method for generators has existed for longer than the WEM itself, and the method is based on sound principles, but noted that Mr Geiser did not agree.

- In response to a question from Ms Guzeleva, Mr Geiser noted that, in the NEM, every MW of load pays for its share relative to total load – for example if the total load is 1,000 MW, then a 100 MW load would pay 10%. Mr Geiser noted that the NEM approach was too soft and that the concept of the Runway Method makes sense in terms of allocating a larger proportion than pro-rata.

Ms Guzeleva noted the group was back to the same position (i.e. those that are negatively affected by a proposal have very strong objections to the proposal irrespective of whether the proposal is consistent with the agreed principles).

Ms Guzeleva noted that the size of the largest load will soon increase from 120 MW to over 200 MW, and it was unreasonable to keep the current cost allocation method in place.

Ms Guzeleva noted that we could go with the approach that is used in the NEM or an alternative option for AEMO to assign risk factors to the different types of loads. Ms Guzeleva noted that there have been assertions that a storage facility carries a significantly lower risk than its transmission connection and asked whether it would be fairer to allocate Contingency Reserve Lower costs based on the risk associated with transmission connections rather than the loads, noting that this may have the same effect for facilities behind a single connection point.

Ms Guzeleva asked if there was a way for the AEMO to determine risk factors for facilities based on network connections rather than trying to second guess what the next big load is and have a threshold which could end up been wrong in two or three years' time.

Mr Draper noted that the current proposal was to apply the Runway Method first to the loads and ten to the networks.

Ms Guzeleva suggested to only apply the method to the network connections and asked whether that would make any difference.

Mr Draper summarised that Ms Guzeleva was proposing that, as the network tripping is a bigger risk than any BESS, then it may be appropriate to allocate Contingency Reserve Lower Costs based only on the network risk.

Ms Guzeleva noted there were two layers, the Facility risk and the network risk, and regardless of how the risk for loads differ, the transmission connection may be the "weakest link".

Ms Guzeleva noted that loads and generation are not currently treated equally – the Runway Method applies to generators but

Item	Subject	Action
	not to loads, and the intent was to try to bring them into some sort of alignment. Ms Guzeleva noted that the point has been made that storage facilities have lower risk of tripping in comparison to generators. Ms Guzeleva asked the CARWG to provide their views. • Mr Schubert considered that the Runway Method is reasonable if some of what Mr Geiser had suggested can be adopted and not make it so binary and so onerous on the biggest load. Ms Guzeleva noted that allocating most costs to the largest load is the point of the Runway Method, and it would no longer be the "Runway Method" if something was done to smooth out this effect. Ms Guzeleva asked Mr Geiser to provide EPWA with the calculations for his proposal to make sure that EPWA has a proper understanding of it. Ms Guzeleva asked the CARWG whether the focus should be on transmission risk because loads, especially storage, may not have the same Facility Risk as generators. Mr Draper asked if AEMO had any insight into the comparative risk of tripping between BESS and generators. • Mr Price responded that he could look into the statistics, but he expects that there is clearly a higher risk for a mechanically spinning generator versus an inverter. Ms Guzeleva asked if a synchronous generator would have a different risk profile. • Mr Price noted that it would depend on the Facility, its location, its control scheme and its protection scheme. • Mr Price indicated that there are different causes of faults for synchronous machines versus asynchronous machines, and that allocation of costs comes down to the fundamentals of fairness around risk allocation. • Mr Price agreed with Mr Geiser that the system requires large batteries, and that the Runway Method may disincentivise a large battery from delivering what the system needs, but it is ultimately the plant configuration that determines its risk to the system. Ms Guzeleva noted that some type of a risk factor assignment may actually be the right way to go, because loads may differ considerably and may have completely different profiles in terms of their forced outages. • Mr Price noted that the AEMO has to cover the risk of the largest load tripping irrespective of its type. • Mr Parrotte noted that anything can trip at any point and that AEMO must cover any credible risk.	

Item	Subject	Action
	Ms Guzeleva asked, with regard to storage, if it was the connection or if it was the storage facility that was likely to trip. • Mr Parrotte noted that this would depend on how the facility was configured and if the battery has one 200 MW connection that could trip at any point. Ms Guzeleva noted that was exactly what she was referring to and asked if it is the risk of the battery tripping that needs to be covered or the risk of a particular network connection, and noted that Mr Geiser has advised that they have never experienced a battery trip. • Mr Parrotte indicated that a battery may have a lower risk of tripping than a synchronous generator, but it can trip, so AEMO has to address this risk when it sets the Contingency Reserve Lower quantity. Ms Guzeleva noted that AEMO has been carrying 70% of spinning reserve and load rejection traditionally and asked what that was based on. • Mr Parrotte noted that this was because the system responds in other ways when the frequency goes up or down. Ms Guzeleva asked if that was equally true for loads and generators. • Mr Price noted that that the 70% multiplier is a simplification of the physics of the system, and that this will be more dynamic in the future, based on load conditions. • Mr Price indicated that you get a response if either a load or generator trips, and it will not necessarily be symmetrical, but this just means that AEMO would need to purchase more or less of the services (Contingency Reserve Raise or Contingency Reserve Lower). Mr Draper noted that AEMO needs to cover any credible risk and questioned if the probability of the battery having a forced outage is zero. • Mr Price noted that AEMO considers any single Facility with a single connection point to be a credible contingency, irrespective of whether they have ever tripped. Mr Price noted that the only time there would be lower risk was if there were two totally distinct Facilities with separate connections that may have been aggregated, because they share the same loss factors, and AEMO would not consider it credible that they would both trip at the same time. Ms Guzeleva asked Mr Price to advise what the requirement for AEMO to determine the Facility risk value means in practice. Ms Guzeleva noted that there were three options: • continue with the current cost allocation method;	

Item	Subject	Action
	• the existing proposal; and • Neoen's proposal.	
	ACTION: Neoen to provide EPWA with the calculations for its proposal to allocate Contingency Reserve Lower costs so that EPWA can make sure that it has a proper understanding of it.	**Neoen**
	ACTION: AEMO to provide further information on the risk of tripping for loads, batteries and generators.	**AEMO**
	ACTION: AEMO to advise what a requirement for it to determine the risk factor of a facility would mean in practice.	**AEMO**
	(c) Contingency Reserve Raise –Treatment of Multiple Dispatchable Units under the Runway Method Mr Draper noted that, if a generator has two units and two separate metering points, then the two units should be treated separately from the perspective of applying the Runway Method because the units are electrically independent. Mr Draper discussed a proposal for the process that AEMO would follow in assessing multiple dispatchable units (slide 24) and how Facilities would be assigned a Facility Risk Value as either a single aggregated unit or separate dispatchable units. • Mr Schubert noted that AEMO, and Western Power in some cases, would need to look at each Facility to determine what their Credible Contingency is, noting that they would not only need to take into account whether a Facility had electrically separate control systems or protection systems but also whether the two connection points could actually trip at the same time. Mr Schubert noted there would need to be a process to identify what are credible contingencies for each Facility. Ms Guzeleva noted that this suggests that AEMO would need to determine the risk on a case-by-case basis. • Mr Price noted it would be difficult to set a prescriptive process in the rules to assess what a credible risk is. Mr Price suggested that AEMO could be provided a head of power to define a risk quantity but that he would need to discuss this internally within AEMO to see if this would be supported. • Mr Price and Mr Parrotte noted that this proposal may require facilities to provide AEMO with more information about the facilities – how they are configured, how the control schemes interact and other more detailed engineering inputs.	

Item	Subject	Action
	Mr Draper noted that it would be hard to design definitive rules for this but it appeared that much of the focus would on the other side of the switchboard. Ms Guzeleva noted that implementing this proposal may only require a slight amendment to the 1 October 2023 rules.	
	ACTION: AEMO to advise whether it would support AEMO being given a head of power to define a Contingency Reserve Raise risk factor for facilities with multiple units behind multiple connections.	**AEMO**
	(d) Market Fees – BESS Cost Recovery Discussion of this agenda item was deferred due to time constraints.	
7	**Next Steps** The Chair indicated that EPWA would consider next steps as a result of the issues raised.	
8	**General Business** No general business was discussed.	

The meeting closed at 3:05pm.

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 6 April 2023)

Market Advisory Committee (**MAC**) Meeting 2023_04_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
None			

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						
None						
Standard Rule Change Proposals with First Submission Period Closed						
RC_2014_05	02/12/2014	IMO	Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price	Medium	Publication of Draft Rule Change Report	25/08/2023
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Publication of Draft Rule Change Report	25/08/2023

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	Medium	Publication of Draft Rule Change Report	25/08/2023
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
2023/37	31/03/2023	Wholesale Electricity Market Amendment (Tranche 6A Amendments) Rules 2023	• Schedule A will commence on 17/04/2023 • 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 D will commence on 17/04/2023 • 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 Amendments) Rules 2020	• Amending Rules in Schedule C will commence at the times specified by the Minister in notices published in the Gazette.

Agenda Item 8: Reserve Capacity Mechanism Review – Draft Information and Consultation Paper

Market Advisory Committee (**MAC**) Meeting 2023_04_20

1. Purpose

To provide the MAC with the draft Reserve Capacity Mechanism (RCM) Review - Information (Stage 1) and Consultation (Stage 2) Paper, for review and guidance to the Coordinator on the proposals and questions in the draft Consultation Paper.

2. Recommendation

The MAC is asked to:

- note the draft RCM Review Information (Stage 1) and Consultation (Stage 2) Paper (the paper) (**Attachment 3**) and that this paper is in a draft state (Energy Policy WA is still editing the paper);
- note the final design of the elements investigated in Stage 1 of the RCM Review in part 1 of the draft paper; and
- provide any further guidance to the Coordinator of Energy (Coordinator) on the proposals and questions in part 2 of the draft paper.

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

The draft Information and Consultation Paper consists of:

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

- Part 1 - an information paper that presents the final design for elements of the RCM investigated in stage 1 of the RCM review, which were subject to public consultation in September 2022 and extensive consultation with the RCMRWG and the MAC. This part is for information only, presenting the final design for:
    - the Planning Criterion[2];
    - the new Flexible Capacity product; and
    - CRC methodology for facilities other than DSPs.
- Part 2 - a consultation paper that presents:
    - The findings and recommendations arising from stage 2 of the RCM review, presenting proposals for changes to the design of:
        - IRCR;
        - CRC allocation and dispatch for DSPs; and
        - the testing, outages and refunds regime.

Economic analysis projecting the effects the RCM changes on the commercial viability of new and existing facilities, will be included in the published paper.

Energy Policy WA is seeking feedback from the MAC for the draft findings and recommendations from Stage 2 of the RCM Review in part 2 of the draft paper.

To assist with the discussion at the MAC meeting:

- a table that lists the final design elements in part 1 of the draft paper together with a high-level summary of the rationale for each Review Outcome is provided in Attachment 1; and
- a table that lists the draft proposals in part 2 of the draft paper together with a high-level summary of the rationale for each proposal is provided in Attachment 2.

4. Next Steps

The Stage 2 Information and Consultation Paper is planned to be published for a 4 week consultation period in early May.

Following the close of submission, EPWA plans to:

- Develop and publish an Information Paper outlining the final decisions on the proposals from Stage 2;
- Commence Stage 3 of the RCM Review which will include consultation on the detailed design and development of Amending Rules for the implementation of the concepts developed under Stages 1 and 2.

5. Attachments

(1) Summary Table of Final Design Elements in Part 1 of the Draft Information and Consultation Paper

(2) Summary Table of Draft Proposals in Part 2 of the Draft Information and Consultation Paper

(3) RCM Review – Draft Stage 2 Information and Consultation Paper

[2] Some of the amendments have already commenced as part of the Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022.

Attachment 1

Summary Table of Final Design Elements from Part 1 of the Draft Information and Consultation Paper

Chapter	Design Proposal	Rationale
2.1.1 Scope of the Planning Criterion	**Proposal 1** Retain the existing ‘Peak capacity’ product to provide an explicit price signal several years ahead of the need for new capacity to meet peak demand and overall energy supply.	The RCM provides an important price signal to incentivise delivery of the right amount of capacity in the future. Modelling shows that peak demand will continue to cause system stress, even if the peak shifts to later in the day, so the ‘Peak capacity’ product should be retained.

Chapter	Design Proposal	Rationale
	Submissions on the stage 1 consultation paper supported retaining the peak capacity product. **Review Outcome:** The existing peak capacity product will be retained.	

Chapter	Design Proposal	Rationale
	Proposal 2 1. The RCM will not include a specific product to manage minimum demand. 2. The RCM design and the capacity certification process will seek to avoid incentives for new facilities to be configured in ways that could make minimum demand more difficult to manage, such as high minimum stable generation.	Minimum demand is an emerging issue, but other mechanisms to manage minimum demand will be more effective than designing a bespoke capacity product in the RCM. This will be considered again as part of the Demand Side Response Participation Review.
	Most submissions supported using mechanisms outside the RCM to manage minimum demand. **Review Outcome:** The RCM will not include a specific product to manage minimum demand at this time.	

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="4"></td><td>Proposal 3
Introduce a new capacity product to the RCM (alongside the existing peak capacity product) to incentivise flexible capacity that can start, ramp, and stop quickly.</td><td>The increasing difference in demand between mid-day, caused by PV growth, and the evening peak has highlighted the need for flexible capacity to maintain reliability. Therefore, an additional flexible capacity product is being proposed to provide incentives for capacity that is capable of rapid start and stop, and fast ramping up or down.</td></tr>
<tr><td colspan="2">Submissions supported the introduction of a flexible capacity product.

Review Outcome: A new flexible capacity product will be introduced to the RCM. Amending Rules will be developed and consulted on in stage 3 of the RCM Review.</td></tr>
<tr><td>Proposal 4

Volatility in operational load and intermittent generation over short timeframes can be managed through ESS and re-dispatch, so the RCM Planning Criterion will not include any reference to volatility in the output of intermittent facilities.</td><td>Volatility in operational load and intermittent generation output over shorter timeframes can continue to be managed through the ESS market.
The expectation is that facilities certified for the flexible capacity product will also be capable, and be accredited, to provide ESS.</td></tr>
<tr><td colspan="2">Most submissions agreed, but several noted that their view could change depending on how the ESS markets develop and whether the new flexible capacity product encourages commissioning of enough ESS capable facilities. One participant noted a desire for the costs of volatility to be paid by those causing the volatility.
Review Outcome:
The RCM Planning Criterion will not include provisions for intermittent output volatility at this time.
Facilities holding flexible capacity credits will be required to accredit for all types of Frequency Co Optimised Essential System Service (FCESS) that they are capable of providing.</td></tr>
</table>

Chapter	Design Proposal	Rationale
2.1.2 The Peak Capacity Product	**Proposal 5** The two current limbs of Planning Criterion will be retained, requiring sufficient capacity to: • meet the 10% POE demand, and • achieve EUE no greater than a specified percentage of expected demand.	The review of international capacity mechanisms shows that a single-limb criterion risks missing some aspects of reliability, so it remains appropriate to retain a two limbed Planning Criterion, similar to the current Planning Criterion. The modelling demonstrates that the current limb (a) – the 10% POE peak exceedance measure – remains appropriate.
	Submissions supported retaining both limbs of the existing Planning Criterion. **Review Outcome:** The existing limbs of the Planning Criterion will be retained.	
	Proposal 6 Amend the reserve margin so that: • sub-clause 4.5.9(a)i uses the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to forced outage, rather than a hardcoded percentage; and • sub-clause 4.5.9(a)ii refers to the largest contingency on the power system, rather than the largest generating unit. Introduce the proposed amendment to clause 4.5.9(a)(ii), in time for the next Reserve Capacity Cycle.	Unless sub-clause (ii) is changed before the next reserve capacity cycle, the Reserve Capacity Target may be too low to ensure that there will be enough capacity if the largest contingency occurs at the same time as peak demand.

Chapter	Design Proposal	Rationale
	Most submissions supported these changes, although one respondent expressed concern that the changes could increase the reserve margin, thus increasing costs to consumers. AEMO noted that the WEM Rules would need to provide guidance for its assessment of historical outages. **Review Outcome:** The rule change to amend clause 4.5.9(a)ii commenced on 1 January 2023 as part of the *Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022*. Sub-clause 4.5.9(a)i will be amended to use the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to forced outages, rather than a hardcoded percentage. Amending Rules will be drafted and consulted on in stage 3 of the RCM review.	
	Proposal 7 The target EUE percentage in the second limb of the RCM Planning Criterion will remain at 0.002% of annual energy consumption.	Given the uncertainty about the future reference technology, and therefore about the BRCP, it is considered that there is currently no strong justification for changing the EUE target.
	Review Outcome: EPWA has further considered the target EUE percentage, and has included a new proposal in Part 2 of this paper (see the table in Attachment 2 and section 5.4 of the draft paper).	
2.1.3 The Flexible Capacity Product	**Proposal 8** The Planning Criterion will include a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the capacity year from either the 10% or 50% POE load forecasts.	System stress modelling indicates that ramping needs will become more extreme in the future. This need cannot be met by all capacity that is eligible for the existing ‘Peak’ capacity service. Without a separate financial incentive, there may not be sufficient flexible capacity to move supply quickly from the low load in the middle of the day through to the evening peak.

Chapter	Design Proposal	Rationale
	All submissions supported the inclusion of a new Planning Criterion limb for flexible capacity. **Review Outcome:** The Planning Criterion will include a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the recent capacity year from either the 10% or 50% POE load forecasts. <u>Certification of Facilities Providing Flexible Capacity</u> The quantity of flexible CRC allocated to a facility will be capped at: • its CRC for peak capacity; and • the maximum MW quantity that it could reach four hours after being dispatched from a cold start. The WEM Rules will require AEMO to set maximum standards for: • minimum stable loading level; • start time (time from receiving a dispatch instruction when unsynchronized to reaching the facility controllable range); • minimum running time (time from receiving a dispatch instruction when in a “cold” state to turn on, run, and turn off again); • stop time (time from receiving a dispatch instruction when running at the minimum of its controllable range to ramp down to zero output); and • restart time (time from desynchronising to synchronizing). The minimum stable loading level is particularly important for the effectiveness of this product, and is likely to be 10% or less of the facility nameplate capacity. <u>Dispatch of Facilities Providing Flexible Capacity</u> Facilities providing flexible capacity will be dispatched for energy through the already established dispatch algorithm, and will not be explicitly held in reserve for later use.	

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="2">2.3 Benchmark Reserve Capacity Price</td><td>Proposal 9
The ERA will remain responsible for setting the detail of the method used to calculate the BRCP.
The WEM Rules will provide guidance for the ERA on the factors to be considered in setting the BRCP methodology.</td><td>While details of the BRCP determination can be delegated to a WEM Procedure, it is considered that the WEM Rules should provide guidance or a high-level methodology for setting the BRCP.

The current structure of the BRCP Procedure will remain relevant for determining the fixed costs of the facility and the approach to annualization, but it will need to be extended to include new steps covering the capacity de-rating, NAQs, and the use of gross or net CONE.</td></tr>
<tr><td colspan="2">All submissions supported the ERA setting the BRCP methodology according to principles set out in the WEM Rules. One participant noted a desire for the BRCP methodology to balance investment certainty with the need for flexibility.

Review Outcome:

The ERA will set the BRCP methodology, according to guidance in the WEM Rules.

The guidance in the WEM Rules will include a principle to set out process steps to determine parameter values in preference to recording only a fixed parameter value, especially where those parameters are likely to change markedly from year to year.</td></tr>
</table>

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="2"></td><td>Proposal 10
The WEM Rules will define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortised over the expected life of the facility.
A BRCP is to be calculated for each of the Peak capacity product and flexible capacity product, and the BRCP methodology must differentiate between the two.
The ERA review of the BRCP methodology (under clause 4.16.9) must consider the appropriate reference technology, the design life of the relevant facility, and identify any cost components that differ between providers of Peak capacity only and Peak plus flexible capacity.</td><td>The analysis shows that an OCGT is likely to remain the new entrant with the lowest capacity costs for at least the next few years, until the trajectory of battery storage costs become clear.
At some point battery storage of an appropriate length will become lower cost than an OCGT, or it will no longer be credible for OCGT to be built. At that point, the reference technology for the BRCP must change.
In the meantime, both OCGT and battery storage can be configured to provide flexible capacity, so it is reasonable to expect that the reference technology for Peak capacity and flexible capacity will be the same.
The configuration of a facility that provides flexible capacity is likely to be slightly different to that of Peak capacity, for example OCGT likely faces additional costs to reduce its level of minimum generation.</td></tr>
<tr><td colspan="2">EPWA has further considered the approach to setting the reference technology for the BRCP methodology, and has included a new proposal in Part 2 of this paper (see Proposal U in Appendix 2 and section 5.5 of the draft report).</td></tr>
</table>

Chapter	Design Proposal	Rationale
	Proposal 11 • Where the reference technology has the highest short-run costs in the fleet, the BRCP methodology can use the simpler gross CONE approach, as this will be the same as the net CONE. • Where the RCM reference technology does not have the highest short-run costs in the fleet, the BRCP methodology must use the net CONE approach to avoid incentivizing overcapacity. • The BRCP will be set based on a facility located in the least congested part of the network. If there is no uncongested network location, the NAQ regime may affect the choice of reference technology. This location will be considered as part of the ERA's regular review of the BRCP methodology.	• Economic modelling indicates that, in the 2020s, when storage volumes are small, storage facilities can make short-run profits by charging when prices are low or negative and discharging in the peak hours. This means that setting the BRCP based on the gross fixed costs of a storage facility could allow a new entrant to recover significantly more than its fixed costs, incentivising overcapacity in the SWIS. • Revenues in the RCM and the real-time markets may be affected by the location of a facility. Where a new facility locates in a congested area of the network, its NAQ allocation will likely be less than its nameplate capacity. The types of capacity likely to be the reference technology are likely to have flexibility over where to locate, and therefore should be assumed to locate in a part of the SWIS where network congestion is minimal.
	Respondents supported retaining a gross CONE approach and understood the rationale for a potential move to net CONE in future, but had concerns. **Review Outcome:** The WEM Rules will not specify the use of gross or net CONE, but will specify that any move away from gross CONE is accompanied by analysis and consultation. The BRCP will be set based on a facility located in an uncongested part of the network. If there is no uncongested part of the network, the BRCP will be set based on a facility located where there is limited congestion.	

Chapter	Design Proposal	Rationale
	Proposal 12 • The administered RCM price curve for the flexible capacity product will be the same as is used for the peak capacity product, as defined in WEM Rule 4.29.1(b)(iv). • The capacity price paid to a facility providing flexible capacity will never be lower than the peak capacity price. • Proposed facilities will have the option to seek a five-year fixed price for flexible capacity, on the same basis as is currently available for peak capacity. A facility must opt for a fixed price for both products, it cannot select fixed price for one product and floating price for the other.	• To incentivise participants to make capacity available for both products from the outset, and prevent strategic withholding at the time of certification, it is important for existing facilities to be eligible for the same payment per MW of flexibility product as new facilities. • Setting the capacity price for a portion of a facility that provides both products at the higher of the two product prices will avoid overcompensation, preserve the pricing signals for both products, and avoid incentives to withhold capacity. • To maintain consistency with the Peak capacity product, facilities providing flexible capacity would have an option to lock in fixed pricing for the flexible capacity for five years, but will only be awarded Capacity Credits if there is a shortage of capacity applying for the floating price option. • As some types of facility (such as pumped hydro storage) may need investment certainty for longer than five years, the five-year fixed price period could change as the need for longer duration storage becomes more pressing.

Chapter	Design Proposal	Rationale
	Respondents supported using the same price curves for both products and raised a number of points about RCM pricing in general. During stage 2 of the review, EPWA has further considered the interaction of the two capacity products. Amendments to the outages and refunds regimes is covered in Attachment 2 and Chapter 5 of the draft paper. **Review Outcome:** The Reserve Capacity Price for the peak capacity and flexible capacity products will be constructed using the same elements, though with different BRCPs and capacity targets. The Reserve Capacity Price paid to a facility providing flexible capacity will never be lower than the peak Reserve Capacity Price. Proposed facilities will have the option to seek a fixed price for flexible capacity on the same basis as is available for peak capacity.	

Chapter	Design Proposal	Rationale
2.2.1 Availability Classes	**Proposal 13** • The current Availability Classes will be removed from the WEM Rules. • The RCM will allocate facilities to one of three Capability Classes (see Design Proposal 17). • CRC allocation methodologies will be amended to consider hybrid facilities as a single entity. • Capability Class 1 facilities will be required to demonstrate sufficient fuel to run for 14-hours. • Capability Class 1 facilities will be required to be available at all hours.	• Retaining the current Availability Classes is not a viable option, as they do not allow for hybrid facilities, which will be increasingly prevalent. • It is therefore proposed to retire the existing Availability Classes and instead include the concept of 'Capability Classes' in the WEM Rules, which better align capacity allocation with firmness of delivery and with availability obligations. • Separating storage from its collocated wind or solar generation for certification purposes will increasingly work against the behaviour required in a world with more intermittent generation. • As the peak requirement changes over time, there will likely be sufficient intermittent generation to provide supply during the middle of the day. However, the duration gap analysis shows that, over time, the peak will flatten and extend, meaning that firm capacity will be needed overnight. • The new capability class arrangements mean that owners of existing facilities could choose to contract for less than 14 hours of fuel per day and be in capability Class 2, with lower CRC, availability requirements to match their fuel availability, and refunds only for not performing in those intervals.

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td></td><td colspan="2">Most submissions supported the new Capability Classes, and the amendment of CRC allocation methodologies to consider a hybrid facility as a single entity. Submissions did not support retaining a 14 hour fuel requirement.

Review Outcome:

The current Availability Classes will be replaced with new Capability Classes:
• Class 1: Unrestricted firm capacity;
• Class 2: Restricted firm capacity; and
• Class 3: Non-firm capacity.
Hybrid facilities will be assessed as a single entity.

Capability Class 1 facilities will be required to be available during all dispatch intervals, unless on an outage, and the requirement to demonstrate sufficient fuel for 14 hours of daily operation will be retained.</td></tr>
</table>

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

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td></td><td colspan="2">
In the submissions, stakeholders also considered that it would be important for the ERA’s BRCP methodology to align with AEMO’s availability duration calculations and considered that a five-year fixed duration would not align with the expected life of facilities providing flexible capacity.
Review Outcome:
The availability duration requirement for new Capability Class 2 facilities which are not DSPs and do not consist solely of ESR components will be 14 hours, to match the Capability Class 1 requirement.
Capability Class 2 facilities which consist solely of ESR components will continue to be assessed based on the linear derating method, which may have a different number of hours required.
DSPs will continue to be assessed based on a 12-hour availability requirement.
Capability Class 2 facilities that are not DSPs and do not consist solely of ESR components will receive peak CRC equal to their maximum instantaneous output pro-rated by the number of hours they can sustain this output divided by the availability duration requirement.
AEMO will forecast the availability duration gap based on the capacity of the existing and committed fleet, and will publish it in the ESOO, including forecasts for subsequent years.
The WEM Rules will set metrics to identify if the duration gap is at risk of not being met in future years and require AEMO to monitor and publish these metrics; and
The Coordinator’s reviews in WEM Rule 4.13B[1] will include consideration of:

Availability duration gap metrics
Availability duration requirements for ESR and DSP facilities.

</td></tr>
</table>

[1] The Coordinator’s first review of the effectiveness of the approach for certification of Reserve Capacity for Electric Storage Resources must be carried out within five years of the start of the 2021 Reserve Capacity Cycle, i.e. by January 2025.

Chapter	Design Proposal	Rationale
2.2.2 Treatment of Outages	**Proposal 15** • CRC allocation will remain on an ICAP basis, with refunds payable for any forced outage. • The reserve margin in the first limb of the Planning Criterion will be set at the greater of the fleet-wide Equivalent Forced Outage Rate on Demand *(*EFORd) and the largest contingency expected at system peak, with AEMO assessing both each year rather than the value being specified in the rules. • Where a facility has an EFORd higher than 10% over a three year period, AEMO will be required to reduce the facility’s CRC by the EFORd. • The method for calculating EFORd will also account for forced outages reported at times the relevant facility had not been called to run. • A Facility whose CRC has been reduced under clause 4.11.1(h) will be excluded from the calculation of fleet outage rate for the purposes of setting the planning criterion reserve margin.	It is considered that: • the current refund regime is working well to incentivise availability, particularly at times when the reserve margin is low; • an ICAP approach provides a stronger incentive for facilities to present all their capacity at peak time; • an ICAP approach better aligns facility payments with actual performance during the capacity year; and • where a specific facility has sustained poor outage performance, the arrangements in clause 4.11.1(h) should be strengthened to require AEMO to reduce the CRC for the facility.

Chapter	Design Proposal	Rationale
	All submissions supported continuing to allocate CRC on an ICAP basis. Some respondents supported the reduction of CRC for facilities with high EFORd, others disagreed on the basis that CRC allocation should be forward looking rather than backward looking, and others thought it necessary to allow discretion for outages which would not reasonably be expected to present a risk to the capacity provider's ability to provide CRC into the future. **Review Outcome:** CRC allocation will remain on an ICAP basis, and the reserve margin will be set accordingly, excluding facilities which have had their CRC reduced due to a high EFORd. If over a three-year period a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd, unless it has evidence that the underlying reasons for the high outage rate have been resolved.	
2.2.3 CRC Allocation	**Proposal 16** To ensure independent estimates of intermittent generator output in historical periods, AEMO will procure expert reports setting out estimates of on behalf of participants**.**	To reduce the potential for bias, it is considered that it is appropriate to require AEMO to procure the expert report on behalf of participants.
	Only one respondent supported AEMO procurement of independent reports, others disagreed. **Review Outcome:** Participants will continue to procure their own expert reports. AEMO will have powers to audit report accuracy: • AEMO will be able to seek independent review of any submitted report and may reject the report if the figures appear to be inflated; and • once a facility is operational, AEMO will compare actual performance with projected performance, and may remove experts from its approved list if their estimates are persistently inaccurate.	

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="2"></td><td>Proposal 17

The methodology to assign CRC to facilities in each of the different Capability Classes will differ by class as follows:
Class 1: Expected output at projected 10% POE peak ambient temperature;
Class 2: Expected output at projected 10% POE peak ambient temperature, adjusted for required availability duration; and
Class 3: To be confirmed in stage two of the RCM review.</td><td>EPWA will continue quantitative analysis of the proposed CRC allocation methods, using common assumptions to ensure comparability, and will propose a preferred option during stage 2 of the RCM Review.
It is considered that the IRCR methodology needs to be adjusted to better align with the intervals used to determine CRC allocation. The IRCR methodology will be considered in the next stage of the RCM review.</td></tr>
<tr><td colspan="2">Submissions generally supported the use of different methods to set CRC for the three Capability Classes. The only aspect of Capability Class 1 certification raised was the temperature requirement. Some respondents considered that a move from 41 degrees to the 10% POE peak ambient temperature was not necessary, as the peak load has moved later in the day in recent years, when ambient temperatures have started to decline.

Submissions raised alternative options for Capability Class 2 certification. These are discussed further in the next section.

Respondents were supportive of amending the current Relevant Level Method for CRC allocation to intermittent generators, but differed in their views on a proposed replacement. Alternative methods for allocating CRC to Capability Class 3 facilities were further explored and consulted on during stage 2 of the review.

Review Outcome:

Capability Class 1 capacity will be assigned CRC based on its expected maximum output at 41 degrees.

Capability Class 2 capacity will be assigned CRC based on its expected maximum output at 41 degrees, adjusted for the required availability duration.

Capability Class 3 CRC allocation is discussed further below.</td></tr>
</table>

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="2"></td><td>The Stage 1 Information paper did not include a proposal for allocating CRC to intermittent generators. However, 3 options were provided for comment.</td><td></td></tr>
<tr><td colspan="2">EPWA developed the final design presented below in extensive consultation with the RCMRWG and MAC. The RCMRWG and MAC supported the final design.
Review Outcome:
<u>Setting CRC for facilities in Capability Class 3</u>
<u>Setting the Fleet CRC</u>
The Fleet CRC is to be set as follows:
(1) Take historical load for the most recent 5 capacity years, and adjust to account for:
(a) output profiles of current levels of distributed energy resources; and
(b) DSP dispatch, unserved energy, and use of NCESS.
(2) Take historical generation output for each Capability Class 3 facility for the same period, and adjust to remove the effects of any involuntary curtailment (whether economic curtailment by the clearing engine, network constraints, or AEMO direction).
(3) Remove data from the capacity year with the lowest peak demand.
(4) For the whole remaining dataset, and for each individual year in the remaining dataset calculate the initial Fleet ELCC as follows:
(a) increase or decrease demand by adding or subtracting the same MWh quantity in each interval to the point at which expected EUE is at the level specified in the planning criterion, assuming that:
(i) Capability Class 1 and 2 facilities have no planned outages;</td></tr>
</table>

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td></td><td colspan="2">(ii) Capability Class 1 and 2 facilities suffer forced outages at historic rates;[2]
(iii) there are no network constraints;
(b) remove all Capability Class 3 facilities from the generation fleet;
(c) reduce load until the EUE is the same MWh quantity as it was in step 4a; and
(d) set the Fleet ELCC equal to the quantity of load reduced in each interval, converted to MW.
(5) Set the Fleet CRC as the lower of:
(a) the Fleet ELCC for the whole dataset; or
(b) the average of the Fleet ELCCs for each individual year.
<u>Allocating the Fleet CRC to individual facilities</u>
The Fleet CRC will be allocated to individual facilities as follows:
(1) Take historical output for each Capability Class 3 facility for the previous five Capacity Years, and adjust to remove the effects of any involuntary curtailment (whether due to offer prices, network constraints, or AEMO direction).
(2) Remove data from the Capacity Year with the lowest system peak demand.
(3) Use the selection rule specified in Section 3.2 of this document to identify the IRCR intervals for each year of the remaining dataset.
(4) For each Capability Class 3 facility:
(a) find the mean historical output in the intervals selected in step 3;
(b) set the Facility proportion equal to the quantity determined for the facility in step (4)(a) divided by the sum over all Capability Class 3 facilities of the quantities determined in step (4)(a).
(c) Set the Facility CRC equal to the Fleet CRC multiplied by the Facility proportion determined in step (4)(b).</td></tr>
</table>

2 EPWA modelled these by Monte-Carlo analysis with multiple iterations of different random facility outages.

Chapter	Design Proposal	Rationale
	The method for setting the IRCR intervals is discussed further in Chapter 3 of the draft report.	

Attachment 2

Summary Table of Draft Proposals from Part 2 of the Draft Information and Consultation Paper

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="3">3.2 IRCR for Peak Capacity</td><td>Proposal A
Continue to set participant IRCR based on contribution to load in high demand intervals.</td><td>Setting a participant's IRCR based on its contribution to load in high demand intervals reflects the Planning Criterion for peak capacity and is reasonably predictable.</td></tr>
<tr><td colspan="2">The MAC supported continuing to use contribution to load in high demand intervals as the basis for setting IRCR.
Consultation Questions:
(1) Do stakeholders support determining IRCR based on contribution to high demand intervals?</td></tr>
<tr><td>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</td><td>In some years, some of the highest demand intervals may fall in winter, as was the case in 2018, the year with the lowest peak demand in the sample analysed. However, these intervals do not represent stress events, and the demand conditions are not reflective of a 1-in-10 year peak demand.
The analysis showed that, in recent years, the shape of the load duration curve differs between years but that the load drops off significantly somewhere between the 5^{th} and 20^{th} interval. This indicates that selecting 12 intervals for the determination of the IRCR for peak capacity remains reasonable.
However, the current IRCR method would select only three intervals from each of the highest demand days and ignore any</td></tr>
</table>

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="2"></td><td>where the peak intervals occurring on each day are not contiguous, the intervening intervals are selected.
The Coordinator’s review of WEM effectiveness will include reviewing whether extreme demand events are forecast to occur outside the hot season.</td><td>other intervals form these days, even if they have higher demand than intervals chosen on other days.

Reducing the minimum numbers of days providing the IRCR intervals to one or two days would increase the difficulty for consumers to manage their IRCR, but EPWA considers that three days would allow more consistent incentive for response to the IRCR signal.</td></tr>
<tr><td colspan="2">The MAC supported this approach to selecting IRCR intervals for the peak capacity product.

Consultation Questions:

(2) Do stakeholders support the proposed interval selection methodology?</td></tr>
<tr><td></td><td>Proposal C:

Remove TDL/NTDL multipliers from the IRCR process.</td><td>Each MWh of usage at peak times has an equivalent contribution to the RCR.

The types of loads that can qualify as NTDL are also likely to be the types of loads that can adjust their consumption during IRCR intervals, meaning that such loads already have an opportunity to manage their exposure to capacity charges.

The TDL/NTDL multiplier reduces the incentive for a participant to make its consumption flexibility available to market dispatch by participating as a DSP.

The NTDL/TDL process is non-trivial for participants and AEMO to manage.

Loads with a flat consumption profile do not contribute to the need for flexible capacity, so the proposed IRCR approach for flexible capacity will inherently allocate low (or no) cost to a load with flat consumption profile.</td></tr>
</table>

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="3"></td><td colspan="2">The MAC and RCMRWG supported removing the distortionary effect of TDLs and NTDLs on cost recovery to level out the treatment of large and small loads.

Consultation Questions:

(3) Do stakeholders support the removal of TDL and NTDL multipliers?</td></tr>
<tr><td>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.</td><td>As a proxy, the current IRCR methodology uses the demand of the new load during the four peak intervals of month n-3. These intervals are unlikely to be reflective of actual system stress, particularly where month n-3 falls in the winter or spring, and in those months will underestimate hot season demand for most loads.

Using the maximum of the median demand in the four peak intervals of any prior month will more appropriately estimate the loads contribution to system peak demand.</td></tr>
<tr><td colspan="2">The RCMRWG and MAC provided only limited feedback on this proposal.

Consultation Questions:

(4) Do stakeholders support the changes to the treatment of new loads?</td></tr>
<tr><td>3.2 IRCR Flexible Capacity</td><td>Proposal E:

Set participant IRCR for flexible capacity based on the load shape in high ramp periods.</td><td>The proposed approach:

• provides an incentive to participants to reduce their contribution to the evening ramp;

• can be replicated by external participants using publicly available data;

• can be predicted in advance with some confidence; and</td></tr>
</table>

Chapter	Design Proposal	Rationale
		• is aligned with the CRC allocation approach for flexible capacity, as it relates to performance during key periods.
	The MAC considered that the proposed approach best complements the way the flexible Reserve Capacity Requirement is set. **Consultation Questions:** (5) Do stakeholders support determining flexible IRCR based on consumer contribution to the ramp during high ramp periods?	
	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.	This approach aligns with the approach used for the peak IRCR, while reflecting the different nature of the flexible capacity requirement.
	Consultation Questions: (6) Do stakeholders support the proposed interval selection rule? (7) Do stakeholders agree that it is necessary for AEMO to publish the forecast ramp?	
4 Demand Side Programmes	**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	This approach allows historical data to be used where it can be relied on for DSPs with large industrial loads, while putting the onus on aggregators to “overfill the programme” to provide evidence that they have sufficient load to curtail when needed.

Chapter	Design Proposal	Rationale
	• different Associated Loads from –the previous year, assign CRC based on a value nominated by the Market Participant.	EPWA considers that the effort is substantially the same for both approaches, with the same outage, testing and refund arrangements.
	Consultation Questions: (8) Do stakeholders support the proposed DSP CRC allocation method?	
	Proposal H: Remove Consumption Deviation Applications (CDAs) from the assessment of DSP CRC.	Excluding maintenance intervals from consideration through CDAs is inconsistent with the treatment of other facilities.
	Consultation Questions: (9) Do stakeholders support the removal of CDAs?	
	Proposal I: Allow sites with collocated load and generation or storage to be Associated Loads of a DSP.	There is no reason to exclude hybrid facilities from participation as DSPS as long as the rules ensure that a Capability Class 2 facility with collocated load and storage cannot self-discharge its storage so as to reduce its IRCR exposure while also receiving capacity credits for that capability.
	Consultation Questions: (10) Do stakeholders agree that sites with generation or storage should be able to be part of a DSP?	
	Proposal J: Adopt a dynamic baseline to measure DSP dispatch performance against. Continue to assess the detailed dynamic baseline methodology.	A dynamic baseline more accurately reflects the actual curtailment delivered by the DSP compared to if it were not called. A dynamic baseline also allows better forecasting of the actual response expected from dispatched DSPs, which allows more secure operation of the power system.

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="2"></td><td>Consider reducing the number of hours that DSPs can be dispatched.</td><td></td></tr>
<tr><td colspan="2">The MAC generally supported a move to dynamic baselines for DSP dispatch.

RCMRWG discussions on DSP dispatch arrangements raised the minimum availability of 200 hours per year as a barrier to participation for some loads which could curtail but are concerned about the impact on their operations.

Consultation Questions:

(11) Do stakeholders agree that measurement against a dynamic baseline would better reflect the actual contribution of DSPs at times of system stress?

(12) Would reducing the 200 hours that DSPs can be dispatched for in a year meet better the WEM objectives and, if so, what would be a more appropriate number of hours?</td></tr>
<tr><td rowspan="2">5.1 Testing</td><td>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><td>There is a need to ensure that a Facility with flexible Capacity Credits can:

• reach its certified output quantity from an unsynchronised state at its certified maximum ramp rate; and

• start, stop, and restart within its certified timings.</td></tr>
<tr><td colspan="2">Consultation Questions:

(13) Do stakeholders see any other aspects of flexible capacity that should be included in the testing regime?

(14) Do stakeholders agree that flexible characteristics can be tested by observation?

(15) Should flexible capacity tests be scheduled at the same time as peak capacity tests?</td></tr>
</table>

Chapter	Design Proposal	Rationale
	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.	DSPs that fail two tests currently have no incentive to restore their capability to meet their original level of Capacity Credits for rest of the Capacity Year. The proposed approach would provide incentive for participants to remedy the unavailability.
	Consultation Questions: (16) Do stakeholders agree with the changes to reserve capacity testing for DSPs? (17) What are stakeholder views on completely aligning the generation and DSP testing regimes?	
5.2 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.	AEMO's outage assessment process will need to compare the forecast need for flexible capacity with the remaining quantity of such capacity.
	Consultation Questions: (18) Do stakeholders agree with the proposed changes to AEMO's outage assessment process?	
	Proposal N: Require flexible capacity holders to lodge outages relating to capability to provide flexible capacity.	The outage regime will need to account for situations where a facility can still provide peak capacity but cannot provide flexible capacity.

Chapter	Design Proposal	Rationale
	Consultation Questions: (19) Do stakeholders agree with the proposed approach to flexible capacity outages?	
	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.	EPWA considers that the infrequent nature of DSP dispatch and the availability incentives provided by the certification and refund processes means that allowing participants to schedule their own outages remains appropriate.
	Consultation Questions: (20) Do stakeholders agree with the proposed approach to DSP outages?	
5.3 Refunds	**Proposal P:** Capacity refunds for both peak capacity and flexible capacity will be paid from a single pool of capacity payments.	If refunds were assessed from the separate payment amounts, the incentive to meet flexible capacity obligations would be weaker than the incentive to meet peak capacity obligation in all situations where the flexible price was less than the peak capacity price. In situations where there is no price premium for flexible capacity (likely indicating that peak capacity is in relatively shorter supply than flexible capacity), there would be no price premium, and no separate payment pool. EPWA considers that this skewed incentive is not appropriate, and that refunds for both products should come from a single payment pool.

Chapter	Design Proposal	Rationale
	Consultation Questions: (21) Do stakeholders agree with the proposed approach to flexible capacity refunds? (22) If stakeholders consider that on the potential refunds for flex-only outages should be capped, what proportion of the total payments would they suggest, and why?	
	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.	A dynamic refund multiplier is an important part of signalling the increased importance of availability at times of system stress. Using a ramp ratio to set the multiplier would mean the multiplier is consistently highest during periods of highest ramp.
	Consultation Questions: (23) Do stakeholders agree with the proposed approach to refund multipliers?	
	Proposal R: Amend the Maximum Facility Refund for DSPs to include the DSM Reserve Capacity Security.	Unlike for generation facilities, participants are unlikely to have invested in significant capital expenditure to set up a DSP. This means that the consequences of losing capacity payments are unlikely to be as severe.

Chapter	Design Proposal	Rationale
		The proposed approach would ensure that DSP owners retain an incentive to be available after they have passed their Reserve Capacity Tests.
	Consultation Questions: (24) Do stakeholders agree with the proposed approach to DSP refunds?	
	Proposal S: Distribute collected capacity refunds to consuming participants rather than other capacity providers.	Currently consumers still pay for the un-provided service when a capacity provider fails to provide capacity. Where AEMO contracts Supplementary Reserve Capacity to replace the missing capacity, consumers will pay again. EPWA considers that it is more equitable to distribute collected capacity refunds to consuming participants rather than capacity providers.
	Consultation Questions: (25) Do stakeholders agree with the proposed distribution of collected capacity refunds?	
5.4 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.	An EUE target of 0.0002% would bring the capacity needed to satisfy the EUE limb closer to the capacity needed for the peak demand limb, and better reflect the reduced appetite for risk of supply interruptions.
	Consultation Questions: (26) Do stakeholders agree with the proposed change to a 0.0002% EUE target in the planning criterion?	

<table>
<tr><th>Chapter</th><th>Design Proposal</th><th>Rationale</th></tr>
<tr><td rowspan="2">5.5 Determination of the BRCP Reference Technology</td><td>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.</td><td>EPWA agrees that the reference technology for the peak and the flexible capacity products may be quite different, to the point of having a different underlying facility types.

EPWA considers that the underlying technology used in the BRCP methodology would be better reviewed and determined by the Coordinator, with the ERA focusing on the other parameters. The potential move to a net CONE approach is driven by the technology selected, and should be included in the Coordinator’s review.</td></tr>
<tr><td colspan="2">Consultation Questions:

(27) Do stakeholders agree that the Coordinator should determine the reference technology for each of the capacity products?

(28) Do stakeholders agree that the potential adoption of a net CONE approach should be considered with the reference technology?</td></tr>
</table>

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

Reserve Capacity Mechanism Review

Stage 2 Information and Consultation Paper

3 May 2023

Working together for a **brighter** energy future.

An appropriate citation for this paper is: Reserve Capacity Mechanism Review – 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

Tables

Figures

Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
BRCP	Benchmark Reserve Capacity Price
CDA	Consumption Deviation Application
CCGT	Combined Cycle Gas Turbine
CONE	Cost of New Entry
CT	Combustion Turbine
DSP	Demand Side Programme
EFORd	Equivalent Forced Outage Rate on Demand
ELCC	Effective Load Carrying Capability
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESR	Electric Storage Resources
ESS	Essential System Services
EUE	Expected Unserved Energy
FCESS	Frequency Co-Optimised Essential System Services
ICAP	Installed Capacity
IRCR	Individual Reserve Capacity Requirement
MAC	Market Advisory Committee
NAQ	Network Access Quantity
NEM	National Electricity Market
OCGT	Open Cycle Gas Turbine
POE	Probability of Exceedance
RCM	Reserve Capacity Mechanism
RCR	Reserve Capacity Requirement
RCOQ	Reserve Capacity Obligation Quantity
RCMRWG	RCM Review Working Group
RCP	Reserve Capacity Price
RLM	Relevant Level Methodology
SWIS	South West Interconnected System
UCAP	Unforced Capacity
VCR	Value of Customer Reliability
VoLL	Value of Lost Load
WEM	Wholesale Electricity Market

Executive Summary

Note: This is a draft paper, all sections are still under development. The executive summary will be added once the paper is finalised.

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, is reviewing 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 for system reliability. The RCM has been subsequently amended to address issues with the initial mechanism and to account for market and system changes.

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

The SWIS has changed substantially since 2012 – the installed capacity of transmission connected intermittent generation has more than doubled, the estimated installed capacity of distributed 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 in a transition to a lower emissions energy system because of the decreasing cost of renewable facilities, the Federal Government's Renewable Energy Target, increased penetration of DPV, increasing pressure to reduce greenhouse gas emissions and consumers' demand for 'green' products. At the same time, other generation technologies, such as battery storage, are becoming more viable and new sources of dispatchable capacity, such as Virtual Power Plants, are being trialled for future use. Some of these 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 generation in the SWIS since the RCM was implemented, and the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation, the Coordinator and the MAC were concerned that the current RCM design may no longer be fit for purpose.

1.1.3 Scope of the 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; and
- Energy Price Limits.[1]

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 Benchmark Reserve Capacity Price (BRCP); and.
    - the methods for assigning Certified Reserve Capacity (CRC).[2]
- 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 rule amendments.

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

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

In July 2022, the Minister for Energy directed EPWA to investigate policy options to penalise 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 will be conducted separately in due course.

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[3], including the Scope of Works for the review, the Terms of Reference for the RCMRWG, papers for RCMRWG and MAC meetings and detailed minutes for each meeting.

1.2 Purpose and Structure of this Paper

This paper consists of two parts:

- Part 1 is an information paper that presents the final design for elements of the RCM investigated in stage 1 of the RCM Review, and that were subject to public consultation in September 2022. Part 1 is for information only, presenting the final design for:
    - the Planning Criterion;[4]
    - the new Flexibility Capacity product;
    - the BRCP; and
    - CRC determination for facilities other than DSPs.
- Part 2 is a consultation paper that:
    - sets out the findings and recommendations arising from stage 2 of the RCM Review, presenting proposals for changes to the design of:
        - IRCR;
        - CRC allocation and dispatch for DSPs;
        - the testing, outages and refunds regime;
    - presents new proposals for two aspects of stage 1 scope:
        - the unserved energy target in the Planning Criterion; and
        - the party responsible for setting the BRCP reference technologies; and
    - presents a projection of the effects the RCM changes on the commercial viability of new and existing facilities [to be included in the paper before publication].

Part 3 includes appendices:

- Appendix A provides a summary of the feedback on the Reserve Capacity Mechanism Review Stage 1 Consultation Paper (Stage 1 Paper) and the Coordinator's responses to the feedback.
- Appendix B provides examples of the application of the new IRCR interval selection rule to historical years.

---

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

[4] The amendments to the Planning Criterion have already commenced as part of Tranche 5 of the Energy Transformation Task Force reforms.

1.3 Call for Submissions

Note: This is a draft consultation paper that is still under development. The consultation will commence upon publication of the final consultation paper and be based on that final paper.

Stakeholder feedback is invited on the recommended changes to the RCM from Stage 2 of the Review, as outlined in Part 2 of this paper. Submissions can be emailed to energymarkets@dmirs.wa.gov.au. Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00pm WST on Wednesday 31 May 2023. Late submissions may not be considered.

PART ONE – INFORMATION PAPER

2. Confirmation of Stage 1 Design Elements

This chapter revisits the proposals from the Stage 1 Paper and the consultation responses, and sets out the final revised design for:

- the Planning Criterion;
- the BRCP;
- CRC for intermittent generators; and
- the Flexibility product.

Proposals are numbered as they were in the Stage 1 Paper. Where there is no change from the proposal, background to and rationale for the proposal can be found in that paper.

2.1 The Planning Criterion

The Planning Criterion is a key component of the RCM, as it drives the Reserve Capacity Requirement (RCR), which is the quantity of reserve capacity to be procured. The Planning Cr requires AEMO to procure sufficient capacity to:

- meet the forecast one in ten year peak demand, plus a reserve margin; and
- ensure that unserved energy is less than 0.002% of total annual demand.

2.1.1 Scope of the Planning Criterion

The Stage 1 Paper explored different sources of system stress that the SWIS can expect to experience as the energy transition continues, and considered whether these stressors should be addressed by the RCM or through other means. Stressors that are to be addressed in the RCM must be included in the Planning Criterion, which drives the RCRs in each Capacity Year.

Proposal 1

> *The existing 'Peak capacity' product will be retained. This product provides an explicit price signal several years ahead of the need for new capacity to meet peak demand and overall energy demand.*

Submissions on the Stage 1 Paper supported retaining the peak capacity product.

Review Outcome

The existing peak capacity product will be retained.

Proposal 2

1. *The RCM will not include a specific product to manage minimum demand.*
2. *The RCM design and the capacity certification process will seek to avoid incentives for new facilities to be configured in ways that could make minimum demand more difficult to manage, such as high minimum stable generation.*

Most submissions supported using mechanisms outside the RCM to manage minimum demand. One respondent considered that the RCM should include a product to encourage increased demand during low-load periods, and another respondent considered that EPWA's ongoing DER and the SWIS demand assessment (SWISDA) work[5] may identify potential for the RCM to contribute to manage low-load periods.

During stage 2, EPWA has worked to ensure that other design decisions do not exacerbate minimum demand issues, including in the:

- flexible capacity certification requirements; and
- DSP availability requirements.

AEMO's ongoing procurement of Non-Co-Optimised Essential System Services (NCESS) for minimum demand support highlights that minimum demand remains an ongoing concern. EPWA will again consider the need for a dedicated minimum demand service as part of its Demand Side Response Review.

Review Outcome

The RCM will not include a specific product to manage minimum demand at this time.

Proposal 3

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

Submissions supported the introduction of a flexible capacity product.

Review Outcome

A new flexible capacity product will be introduced to the RCM. Amending rules will be developed and consulted on in stage 3 of the RCM Review.

Proposal 4

> *Volatility in operational load and intermittent generation over short timeframes can be managed through ESS and re-dispatch, and the flexible capacity product will provide sufficient capacity that is capable of providing these services, so the RCM Planning Criterion will not include any reference to volatility in the output of intermittent facilities.*

Most submissions agreed, but several noted that their view could change depending on how the ESS markets develop and whether the new flexible capacity product encourages commissioning of enough ESS capable facilities. One participant noted a desire for the costs of volatility to be paid by those causing the volatility.

ESS cost allocation is considered as part of EPWA's review of cost recovery methodologies.[6]

Review Outcome

The RCM Planning Criterion will not include provisions for intermittent output volatility at this time.

Facilities holding flexible capacity credits will be required to accredit for all types of Frequency Co-Optimised Essential System Service (FCESS) that they are capable of providing.

5 For more information see: https://www.wa.gov.au/government/announcements/swis-demand-assessment

6 For more information see: https://www.wa.gov.au/government/document-collections/cost-allocation-review

2.1.2 The Peak Capacity Product

The existing Planning Criterion has two limbs:

- a forecast peak limb, requiring sufficient capacity to meet the forecast 10% probability of exceedance (POE) peak load, plus additional amounts to manage outages, FCESS and Intermittent Loads; and
- an Expected Unserved Energy (EUE) limb, requiring sufficient capacity to limit EUE to 0.002% of expected demand.

The Stage 1 Paper proposed to retain the existing limbs with changes to the first limb of the Planning Criterion. Some of these changes have already been implemented.

Proposal 5

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

- *meet the 10% POE demand, and*
- *achieve Expected Unserved Energy (EUE) no greater than a specified percentage of expected demand.*

Submissions supported retaining both limbs of the existing Planning Criterion.

Review Outcome

The existing limbs of the Planning Criterion will be retained.

Proposal 6

Amend the reserve margin so that:

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

Introduce the proposed amendment to clause 4.5.9(a)(ii) to change the determination of the largest contingency for the calculation of the reserve margin, in time for the next 2023 Reserve Capacity Cycle (for capacity to be provided from 1 October 2025).

Most submissions supported these changes, although one respondent expressed concern that the changes could increase the reserve margin, thus increasing costs to consumers. AEMO noted that the WEM Rules would need to provide guidance for its assessment of historical outages.

Review Outcome

The rule change to amend clause 4.5.9(a)ii commenced on 1 January 2023 as part of the *Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022*.

Sub-clause 4.5.9(a)i will be amended to use the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to forced outages, rather than a hardcoded percentage. Amending Rules will be drafted and consulted on in stage 3 of the RCM review.

Proposal 7

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

EPWA has further considered the target EUE percentage and has included a new proposal in Part 2 of this paper (see section 5.4).

2.1.3 The Flexible Capacity Product

The Stage 1 Paper set out the case for, and high-level design of a new flexible capacity product to address the need for flexible capacity.

During stage 2 of the RCM Review, EPWA considered market elements required to implement a flexible capacity product, particularly capacity certification and facility dispatch. These issuers were discussed with and were generally supported by the RCMRWG and are included below for information.

Proposal 8

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

All submissions supported the inclusion of a new Planning Criterion limb for flexible capacity.

Review Outcome

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

Certification of Facilities Providing Flexible Capacity

Flexible capacity certification will be incorporated into the existing Electricity Statement of Opportunities (ESOO) and certification processes.

A facility will not be able to be certified for flexible capacity only – it must also provide peak capacity.

Minimum performance requirements for the flexible capacity product will likely change over time as the load shape changes. The WEM Rules will require AEMO to consider, as part of the ESOO processes, the capability required of facilities to meet the identified need, ensuring that providers of the flexible capacity can move quickly from no output (or from full consumption) in the midday to rapidly increase output (or decrease consumption) as the high ramp requirements begin.

Review Outcome

The quantity of flexible CRC allocated to a facility will be capped at:

- its CRC for peak capacity; and
- the maximum MW quantity that it could reach four hours after being dispatched from a cold start.

The WEM Rules will require AEMO to set maximum standards for:

- minimum stable loading level;
- start time (time from receiving a dispatch instruction when unsynchronized to reaching the facility controllable range);

- minimum running time (time from receiving a dispatch instruction when in a “cold” state to turn on, run, and turn off again);
- stop time (time from receiving a dispatch instruction when running at the minimum of its controllable range to ramp down to zero output); and
- restart time (time from desynchronising to synchronizing).

The minimum stable loading level is particularly important for the effectiveness of this product, and is likely to be 10% or less of the facility nameplate capacity.

Dispatch of Facilities Providing Flexible Capacity

Under the Real-Time Market Rules from New WEM Commencement Day, there is no specific market service for fast-ramping facilities. This means that there is no explicit consideration of whether to hold flexible capacity in reserve for use in later periods. However, the dispatch algorithm will account for ramp constraints and start-up times when dispatching for energy, and will – subject to network constraints – dispatch the lowest cost facilities for energy ahead of higher cost facilities. This means that as long as sufficient flexible capacity is available, the dispatch engine will be able to use it when needed.

In the SWIS, fast ramping facilities are currently more expensive than slower ramping ones, meaning they will effectively be held in reserve unless needed. If slow ramping facilities ever became more expensive than fast ramping facilities, it would be possible for the dispatch engine to dispatch a faster facility ahead of a slower one, and then not have sufficient ramping capability available in a later period.

This risk could be removed by implementing a dedicated ramping service, but doing so would require inter-temporal optimisation, whereby the clearing engine optimises dispatch costs over multiple intervals, rather than sequentially interval-by-interval, as at present.

This would require major changes to the dispatch algorithm and is not necessary at this time. If centralised commitment is implemented in the future, a ramping service could be implemented at the same time.

The MAC supported this approach.

Review Outcome

Facilities providing flexible capacity will be dispatched for energy through the already established dispatch algorithm, and will not be explicitly held in reserve for later use.

2.2 Capacity Certification

The Stage 1 Paper considered various aspects of capacity certification.

2.2.1 Availability Classes

Proposal 13

- *The current Availability Classes will be removed from the WEM Rules.*
- *The RCM will allocate facilities to one of three Capability Classes:*
  - *Class 1: Unrestricted firm capacity;*[7]
  - *Class 2: Restricted firm capacity;*[8] *and*
  - *Class 3: Non-firm capacity*[9]
- *CRC allocation methodologies will be amended to consider hybrid facilities as a single entity.*
- *Capability Class 1 facilities will be required to demonstrate sufficient fuel to run for 14 hours.*
- *Capability Class 1 facilities will be required to be available during all dispatch intervals, unless on an outage.*

Most submissions supported the new Capability Classes, and the amendment of CRC allocation methodologies to consider a hybrid facility as a single entity. Participants raised concerns about:

- How the certification process would work for hybrid facilities. This is addressed in section 2.2.3.
- Revenue sufficiency for hybrid facilities. This is discussed in Chapter 5.4.
- Participant's ability to implement their preferred operational arrangements for hybrid facilities, including the use of collocated storage. EPWA considers that where a facility is capable of operating as either a Capability Class 2 or Capability Class 3 facility, the participant will be able to opt for the Capability Class that best fits their preferred operational profile.

Submissions did not support retaining a 14 hour fuel requirement, arguing that:

- availability is sufficiently incentivised by the refund regime and the need to earn energy revenue;

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

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

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

- a 14-hour duration gap will only occur once all thermal generation has retired;
- the requirement is based on the expected distillate resupply time which is no longer an appropriate benchmark; and
- the fuel requirement should be replaced by a 4-5 hour fuel requirement to match with the current duration of the peak.

The 14-hour requirement stems from AEMO's implementation of the current Availability Class definitions in WEM Rule clause 4.11.4. The WEM Procedure[10] requires participants to demonstrate firm fuel availability for peak trading intervals (8am-10pm) on all business days.

EPWA considers that relaxing the requirement for all facilities to show evidence that they have sufficient fuel to operate during periods of system stress would risk reducing the level of reliability provided for by the WEM Rules, and that doing so would be counter to one of the key principles of the RCM Review.[11] Recent fuel supply issues illustrate the importance of fuel availability and recent changes as part of the Market Power Mitigation Strategy[12] mean that participants now have certainty that the costs of long-term take-or-pay fuel contracts can be reflected in market submissions.

The fundamental reason for having three Capability Classes is to recognise that facilities with firm availability provide a greater contribution to system reliability than those with lower availability. Participants who wish to procure shorter duration fuel contracts can instead seek certification in Capability Class 2 and receive a prorated CRC accordingly.

However, EPWA acknowledges that the current WEM Procedure may be more restrictive than is warranted to ensure fuel availability during times of system stress. The current WEM Procedure requires demonstrating fuel availability during the midday trough, when it is increasingly likely that the majority of the facilities will be dispatched down or off.

EPWA considers that the WEM Rules could provide additional guidance on the implementation of the provisions in clause 4.11.4(a)ii such that AEMO should consider the time of day in which certification in Capability Class 1 requires firm fuel contracts, particularly as the overnight duration gap extends (see section 2.2.3). Offer obligations, testing requirements, and refund incentives will remain in place.

Review Outcome

The current Availability Classes will be replaced with new Capability Classes:

- Class 1: Unrestricted firm capacity;
- Class 2: Restricted firm capacity; and
- Class 3: Non-firm capacity.

Hybrid facilities will be assessed as a single entity.

Capability Class 1 facilities will be required to be available during all dispatch intervals, unless on an outage, and the requirement to demonstrate sufficient fuel for 14 hours of daily operation will be retained.

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

11 That any changes to the RCM should not erode the level of system reliability currently provided for by the WEM Rules.

12 https://www.wa.gov.au/government/document-collections/market-power-mitigation-strategy

2.2.2 Treatment of Outages

Proposal 15

- *CRC allocation will remain on an Installed Capacity (ICAP) basis, with refunds payable for any forced outage.*
- *The reserve margin in the first limb of the Planning Criterion will be set at the greater of the fleet-wide Equivalent Forced Outage Rate on Demand (EFORd) and the largest contingency expected at system peak, with AEMO assessing both each year rather than the value being specified in the rules.*
- *Where, over a three-year period, a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd.*
- *The method for calculating EFORd will also account for forced outages reported at times the relevant facility had not been called to run.*
- *A Facility whose CRC has been reduced under clause 4.11.1(h) will be excluded from the calculation of fleet outage rate for the purposes of setting the planning criterion reserve margin.*

All submissions supported continuing to allocate CRC on an ICAP basis. Some respondents supported the reduction of CRC for facilities with high EFORd, others disagreed on the basis that CRC allocation should be forward looking rather than backward looking, and others thought it necessary to allow discretion for outages which would not reasonably be expected to present a risk to the capacity provider's ability to provide CRC into the future. EPWA agrees that CRC allocation should be based on the expected future ability of a facility to provide capacity, but still considers that it is necessary to strengthen the CRC derating requirements in clause 4.11.1(h). EPWA accepts that the historical outage rate may not represent expected future outage rate, and will include some discretion for AEMO to not apply the derating if it is satisfied that the underlying reason for the outage has been addressed.

Review Outcome

CRC allocation will remain on an ICAP basis, and the reserve margin will be set accordingly, excluding facilities which have had their CRC reduced due to a high EFORd.

If over a three-year period a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd, unless it has evidence that the underlying reasons for the high outage rate have been resolved.

2.2.3 CRC Allocation

Proposal 17

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

Submissions generally supported the use of different methods to set CRC for the three Capability Classes. The only aspect of Capability Class 1 certification raised was the temperature requirement. Some respondents considered that a move from 41 degrees to the 10% POE peak ambient temperature was not necessary, as the peak load has moved later in the day in recent years, when ambient temperatures have started to decline.

Submissions raised alternative options for Capability Class 2 certification. These are discussed further in the next section.

Respondents were supportive of amending the current Relevant Level Method for CRC allocation to intermittent generators, but differed in their views on a proposed replacement. Alternative methods for allocating CRC to Capability Class 3 facilities were further explored and consulted on during stage 2 of the review.

Review Outcome

Capability Class 1 capacity will be assigned CRC based on its expected maximum output at 41 degrees.

Capability Class 2 capacity will be assigned CRC based on its expected maximum output at 41 degrees, adjusted for the required availability duration.

Capability Class 3 CRC allocation is discussed further below.

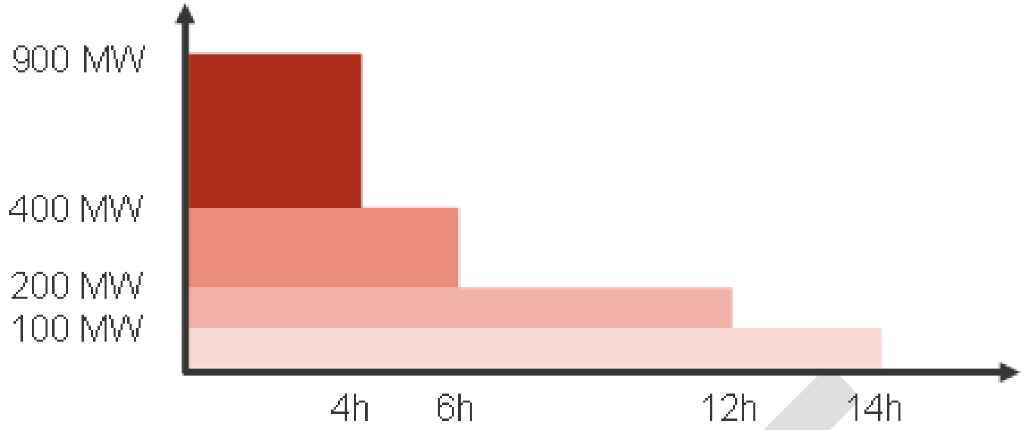
Proposal 14

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

In the Stage 1 Paper, EPWA proposed to use an availability duration target in setting CRC for Capability Class 2 facilities. Under this approach the duration gap is assumed to be met by either generation (primarily overnight wind in later years) or by increasing storage volumes to allow a longer discharge period.

Some respondents suggested that AEMO could instead separate the duration requirement into several parts and select Capability Class 2 capacity of multiple durations to fill the aggregate requirement, as shown in Figure 1.

Figure 1: Shaped Procurement of Energy Limited Capacity



The same peak requirement would be procured, but the evolving shape of the post-peak would be accounted for by procuring capacity from facilities with a range of availability durations. Rather than prorating the MW based on duration, the duration would become a payment multiplier. Capability Class 1 facilities would get a 100% price multiplier, and a 6h facility would receive a 6/24 multiplier.

EPWA considers that this approach is not appropriate as it would be unfair to Capability Class 1 facilities to move:

- away from providing each MW of CRC available at peak with the same payment;
- towards treating capacity as a MWh contribution instead (at least for Capability Class 2); and
- the RCM towards a MWh target rather than a MW target.

Other respondents suggested a third approach: defining another capacity product to explicitly deal with the duration gap.

Under this option, the capacity mechanism would distinguish between peak capacity, flexible (ramping) capacity, and duration capacity; providing additional incentive for duration rather than applying a derating to capacity based on its availability. Such a duration product would specify availability over a certain number of hours post-peak (determined by AEMO and published in the ESOO), extending over time to eventually span the entire overnight period.

The MAC considered that this approach has merit, but not immediately, as:

- the duration gap is a function of the type and size of facilities participating in the market, rather than an uncontrollable factor such as increasing distributed solar PV penetration;
- short-term storage is projected to be sufficient for SWIS needs for the next decade; and
- with each different incentive signal the market provides, the less each signal factors into investment decision making. The new flexibility product will provide an important signal, and this should be introduced and given a chance to take effect before another capacity product is introduced.

EPWA considers that the relevant duration requirement for new Capability Class 2 facilities should match the Capability Class 1 requirement. The existing method for Capability Class 2 facilities consisting solely of ESR components will remain unchanged as per the scope of the RCM Review.

In the submissions, stakeholders also considered that it would be important for the ERA's BRCP methodology to align with AEMO's availability duration calculations. Respondents considered that a five-year fixed duration would not align with the expected life of facilities providing flexible capacity, which are expected to have at least a 10-year investment life.

EPWA acknowledges the concern over a mismatch between time parameters for technical parameters that affect revenue and the expected life of an investment, particularly in relation to longer duration storage facilities. EPWA will examine this issue at a later date.

Review Outcome

The availability duration requirement for new Capability Class 2 facilities that are not DSPs and do not consist solely of ESR components will be 14 hours, to match the Capability Class 1 requirement.

Capability Class 2 facilities that consist solely of ESR components will continue to be assessed based on the linear derating method, which may have a different number of required hours.

DSPs will continue to be assessed based on a 12-hour availability requirement.

Capability Class 2 facilities that are not DSPs and do not consist solely of ESR components will receive peak CRC equal to their maximum instantaneous output pro-rated by the number of hours they can sustain this output divided by the availability duration requirement.

AEMO will forecast the availability duration gap based on the capacity of the existing and committed fleet, and will publish it in the ESOO, including forecasts for subsequent years.

The WEM Rules will set metrics to identify if the duration gap is at risk of not being met in future years and require AEMO to monitor and publish these metrics, and the Coordinator's reviews under clause 4.13B[13] will include consideration of the:

- availability duration gap metrics; and
- availability duration requirements for ESR and DSP facilities.

Setting CRC for facilities in Capability Class 3

The output of intermittent generators is inherently uncertain, varying from interval-to-interval and from year-to-year. No CRC allocation method will perfectly predict the output of an intermittent facility in a future period of system stress, based on historical output data – CRC allocation will always be an estimate of the expected contribution.

EPWA's objective when developing the method was to identify a CRC allocation method for intermittent generators that:

- ensures that the system reliability objective is met;
- adequately assesses facilities' contribution to system reliability;
- minimizes year-to-year volatility for investors;
- is simple and easy to understand;
- ideally can be replicated by potential investors and other stakeholders; and
- ideally can be adapted for use on DSPs[14] and is consistent with the calculation of IRCRs.

[13] The Coordinator's first review of the effectiveness of the approach for certification of Reserve Capacity for ESRs must be carried out within five years of the start of the 2021 Reserve Capacity Cycle (i.e. by January 2025).

[14] See Chapter 4 for further discussion.

Setting up the Process

The approach to determining intermittent facility CRC can be separated into two parts:

(1) Determining the total CRC to be allocated to the fleet as a whole; and

(2) Determining how to allocate the total CRC across all facilities.

The Stage 1 Paper identified two methods that used ELCC to set the total CRC to be allocated to the intermittent fleet, and one that assessed each facility individually, without considering the overall contribution of the fleet. Submissions and subsequent discussions at the RCMRWG and the MAC agreed that an approach which considered the overall fleet contribution was appropriate, and EPWA did not consider individual assessment any further.

Respondents also noted a desire to mitigate year-to-year volatility in CRC outcomes. Smoothing out year-to-year volatility in Fleet ELCC could improve certainty for investors, but EPWA remained concerned that any method for reducing volatility should not cause CRC allocations to overstate performance by increasing the weight placed on performance in lower stress periods. As a result, the proposed fleet ELCC process will include measures to reduce year-to-year volatility while maintaining focus on high stress periods.

Setting the Fleet CRC

Volatility due to unusually high performance in a single year can be mitigated by setting the Fleet ELCC to the lower of:

- the Fleet ELCC calculated for the whole period; and
- the average of the Fleet ELCCs calculated for each individual year of the period.

Conversely, some years do not have any significant stress periods. The effect of low stress periods can be mitigated by removing the year with the lowest peak from the data used to calculate CRC. For example, 2018 has the lowest peak demand of any year in the period 2015-2021: approximately 300 MW lower than any other year, and 750 MW lower than the highest peak interval.

EPWA has used an EUE approach to calculate the Fleet ELCC,[15] using the target from the second limb of the Planning Criterion. This approach is less reliant on firm facilities than a cumulative outage probability table, so is more suitable for systems with high intermittent penetration. Table 1 shows the results for several different EUE targets for the load scaling step. The approach gives similar results across a range of EUE targets, including the current and proposed planning criterion EUE target. For very small EUE target parameters, the calculated fleet ELCC becomes less consistent, as it is driven by a smaller and smaller number of intervals.

[15] See the Stage 1 Paper for more detail on the ELCC method.

Table 1: Fleet ELCC (2016-2020 less 2018) for different EUE Targets, with Stochastic Sampling of Forced Outages over 250 Iterations

EUE Target	Fleet ELCC (MW)	UE Intervals driving EUE, intermittents included	UE Intervals driving EUE, intermittents removed	With/without intermittent UE period ratio
0.00000%	288	1	1	1
0.00005%	280	12	12	1
0.00010%	255	19	23	0.83
0.00015%	251	27	34	0.79
0.00020%	247	33	44	0.75
0.00050%	246	63	88	0.72
0.00100%	248	109	151	0.72
0.00150%	249	147	201	0.73
0.00200%	252	178	247	0.72
0.00400%	259	293	406	0.72
0.01000%	271	569	748	0.76

Review Outcome

The Fleet CRC is to be set as follows:

(1) Take historical load for the most recent 5 capacity years, and adjust to account for:

(a) output profiles of current levels of distributed energy resources; and

(b) DSP dispatch, unserved energy, and use of NCESS.

(2) Take historical generation output for each Capability Class 3 facility for the same period, and adjust to remove the effects of any involuntary curtailment (whether economic curtailment by the clearing engine, network constraints, or AEMO direction).

(3) Remove data from the capacity year with the lowest peak demand.

(4) For the whole remaining dataset, and for each individual year in the remaining dataset calculate the initial Fleet ELCC as follows:

(a) increase or decrease demand by adding or subtracting the same MWh quantity in each interval to the point at which expected EUE is at the level specified in the planning criterion, assuming that:

(i) Capability Class 1 and 2 facilities have no planned outages;

(ii) Capability Class 1 and 2 facilities suffer forced outages at historic rates;[16]

(iii) there are no network constraints;

(b) remove all Capability Class 3 facilities from the generation fleet;

16 EPWA modelled these by Monte-Carlo analysis with multiple iterations of different random facility outages.

(c) reduce load until the EUE is the same MWh quantity as it was in step (4)(a); and

(d) set the Fleet ELCC to the quantity of load reduced in each interval, converted to MW.

(5) Set the Fleet CRC as the lower of:

(a) the Fleet ELCC for the whole dataset; or

(b) the average of the Fleet ELCCs for each individual year.

Allocating the Fleet CRC to Individual Facilities

During stage 2 of the review, EPWA carried out additional analysis on four options for CRC allocation to intermittent generators:

- the Delta ELCC Method, where first-in and last-in Facility ELCCs are calculated and used to distribute the Fleet CRC.
- the EPWA Hybrid Method, where the Fleet CRC is distributed based on facility performance in stressed intervals, using Load for Scheduled Generation (LSG) as the metric for which intervals to consider;
- the Collgar Hybrid Method, where the Fleet CRC is distributed based on facility performance in stressed intervals, using total demand as the metric for which intervals to consider; and
- the IRCR Method, where the Fleet CRC is distributed based on facility performance during IRCR intervals.

Analysis for the four methods is captured in RCMRWG papers. Ultimately, EPWA (in consultation with the MAC and the RCMRWG) has determined to use the simpler IRCR method. This makes it easier for participants and investors to apply the method themselves, and aligns incentives for capacity suppliers and consumers.

The approach to selecting IRCR intervals was also discussed with the RCMRWG, and is presented for consultation in section 3.2.

This approach, in conjunction with the Fleet ELCC determination, will address all the policy design goals listed in section 2.3.4.

Review Outcome

The Fleet CRC will be allocated to individual facilities as follows:

(1) Take historical output for each Capability Class 3 facility for the previous five Capacity Years, and adjust to remove the effects of any involuntary curtailment (whether due to offer prices, network constraints, or AEMO direction).

(2) Remove data from the Capacity Year with the lowest system peak demand.

(3) Use the selection rule specified in Section 3.2.3 of this document to identify the IRCR intervals for each year of the remaining dataset.

(4) For each Capability Class 3 facility:

(a) find the mean historical output in the intervals selected in step 3;

(b) set the Facility proportion equal to the quantity determined for the facility in step (4)(a) divided by the sum over all Capability Class 3 facilities of the quantities determined in step (4)(a).

(c) Set the Facility CRC equal to the Fleet CRC multiplied by the Facility proportion determined in step (4)(b).

The method for selecting the IRCR intervals is discussed further in Chapter 3.

Proposal 16

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

Only one respondent supported AEMO procurement of independent reports. Other respondents disagreed with the proposal, expressing that:

- the expert report is integral to the project development, approval and financing process, including more than just the estimated output values used for CRC, so having a third party (AEMO) procure the estimated output component would compromise those core project activities and increase overall costs;
- AEMO would be in a difficult legal position if the expert's work is subsequently challenged as having led to an "incorrect" investment decision;
- there are explanations other than bias for a decline in CRC levels over time, including the RLM itself, as the output of a new intermittent generators only impacts the timing of peak LSG intervals (thus shifting the periods used) once it is operational;
- AEMO would be procuring reports from the same set of qualified experts as participants, so they would be unlikely to give significantly different results;
- AEMO would need to manage conflicts of interest among experts, as some are likely to be engaged by competing participants on different developments; and
- it would be more practical to have AEMO raise any discrepancies between the expert report and actual output directly with the participant or the independent expert.

If AEMO were to procure the reports, respondents considered that:

- proponents should be allowed to interrogate and approve assumptions, data quality, and report outcomes prior to finalising;
- AEMO must have processes in place to manage conflicts of interest;
- AEMO must have processes in place to ensure efficient costs; and
- costs should be recovered from project proponents on a 'causer pays' basis.

EPWA acknowledges the complexities in separating this report from the project development and financing process, but considers that additional measures are required to ensure the impartiality of these reports – overly optimistic expert estimates are a risk to power system reliability.

Review Outcome

Participants will continue to procure their own expert reports.

AEMO will have powers to audit report accuracy:

- AEMO will be able to seek independent review of any submitted report and may reject the report if the figures appear to be inflated; and
- once a facility is operational, AEMO will compare actual performance with projected performance, and may remove experts from its approved list if their estimates are persistently inaccurate.

2.3 The Benchmark Reserve Capacity Price

The Stage 1 Paper considered aspects of the BRCP.

Proposal 9

- *The ERA will remain responsible for setting the detail of the method used to calculate the BRCP.*
- *The WEM Rules will provide guidance for the ERA on the factors to be considered in setting the BRCP methodology.*

All submissions supported the ERA setting the BRCP methodology according to principles set out in the WEM Rules. One participant noted a desire for the BRCP methodology to balance investment certainty with the need for flexibility, citing an example of the Weighted Average Cost of Capital value being inappropriately hardcoded in the procedure.

Review Outcome

The ERA will set the BRCP methodology, according to guidance in the WEM Rules.

The guidance in the WEM Rules will include a principle to set out process steps to determine parameter values in preference to recording only a fixed parameter value, especially where those parameters are likely to change markedly from year to year.

Proposal 10

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

EPWA has further considered the approach to setting the reference technology for the BRCP and has included a new proposal in Part 2 of this paper (see section 5.5).

Proposal 11

- *Where the RCM reference technology has the highest short-run costs in the fleet, the BRCP methodology can use the simpler gross CONE approach, as this will be the same as the net CONE.*
- *Where the RCM reference technology does not have the highest short-run costs in the fleet, the use of net CONE approach would need to be considered to avoid incentivising overcapacity.*

- *The BRCP will be set based on a facility located in the least congested part of the network. If there is no uncongested network location, the NAQ regime may affect the choice of reference technology. This location will be considered as part of the ERA's regular review of the BRCP methodology.*

Respondents supported retaining a gross cost of new entry (CONE) approach. Respondents understood the rationale for a potential move to net CONE in future, but were concerned that a move to net CONE could result in:

- reduced investment certainty, due to the difficulty in forecasting energy and ESS revenues as intermittent generation continues to increase;
- new entrants being unable to recover their capital costs; and
- significant additional complexity for negligible benefit.

Respondents proposed that a move to net CONE be:

- held off until experience with a new reference technology can inform modelling assumptions; and
- preceded by additional consultation and analysis.

One respondent requested that the reference facility location instead be in 'any suitable uncongested part of the network', to avoid unnecessary analysis to determine which location was the least congested.

Review Outcome

The WEM Rules will not specify the use of gross or net CONE, but will specify that any move away from gross CONE is accompanied by analysis and consultation.

The BRCP will be set based on a facility located in an uncongested part of the network. If there is no uncongested part of the network, the BRCP will be set based on a facility located where there is limited congestion.

Proposal 12

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

Respondents supported using the same price curves for both the peak capacity and flexible capacity products, ensuring that facilities never receive a lower price for providing flexible capacity than for providing peak capacity, and a fixed price option for facilities providing flexible capacity.

Respondents raised a number of points about RCM pricing, including that:

- the current five-year fixed price horizon for peak capacity is too short, and should be extended to 10 or 15 years;
- volatility in the current RCP will not support long-term investment in flexible generation and storage facilities; and

- EPWA should consider amendments to the current price cap and floor regime and the price curve generally to ensure appropriate signals for participation.

While these items are outside the scope of the current RCM Review, they have been noted, and EPWA is considering them separately.

During stage 2 of the review, EPWA has further considered the interaction of the two capacity products. Amendments to the outages and refunds regimes is covered in Chapter 5 of this paper.

Review Outcome

The Reserve Capacity Price for the peak capacity and flexible capacity products will be constructed using the same elements, though with different BRCPs and capacity targets.

The Reserve Capacity Price paid to a facility providing flexible capacity will never be lower than the peak Reserve Capacity Price.

Proposed facilities will have the option to seek a fixed price for flexible capacity on the same basis as is available for peak capacity.

PART TWO – CONSULTATION PAPER

3. Individual Reserve Capacity Requirements

3.1 Introduction

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

EPWA's goal is to identify an IRCR determination method for consuming participants that:

1. ensures that capacity payments are fully recovered from electricity consumers;
2. allocates costs based on consumers' contribution to the RCR;
3. provides a signal to consumers to amend their electricity use in a way that reduces the RCR;
4. allows costs to be allocated to new loads added during a capacity year, which may provide no or minimal notice of coming online;
5. is simple, cost effective, and easy to understand;
6. ideally aligns with the method(s) used to allocate CRC;
7. ideally minimises year to year volatility for consumers;
8. ideally can be replicated by potential investors and other stakeholders; and
9. is predictable so it incentivises effective management of load during system stress events.

3.2 IRCR for Peak Capacity

3.2.1 Current Approach

Methodology

IRCR is calculated monthly for each participant as follows:

First determine the representative load for each meter:

- If the meter was measuring load during the hot season in the previous capacity year (0800 on 1 December to 0800 on 1 April), the representative load is the median load in 12 intervals selected from the previous hot season as follows:
  - For each of the 4 trading days in the hot season with the highest maximum demand[17] in any Trading Interval, the 3 Trading Intervals with the highest Total Sent Out Generation.
- If the meter was not measuring load during all of the 12 selected intervals, its representative load is its median load in 4 intervals selected from month n-3 as follows:
  - the four intervals with the highest Total Sent Out Generation from that month;

[17] Total Sent Out Generation is used as a proxy for total demand, as this figure includes all system losses.

- multiplied by 1.3 if it is a Temperature Dependent Load (TDL) and 1.1 if it is a Non-Temperature Dependent Load (NTDL) – this allows for expected increase in the hot season months; and
- prorated to the proportion of the month that the meter measured load.

Secondly, sum the representative TDLs and NTDLs for each participant, with another ratio applied to account for meters which were present in the previous hot season.

Finally, allocate IRCRs to participants in proportion to their total load, so that the total sums to the Reserve Capacity Requirement (RCR).

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.

Issues with the Current IRCR Method

The current IRCR method does not consider demand in all system stress intervals. As the analysis in section 3.2.3 shows:

- in some years, the highest demand intervals are spread across six or seven days. The current IRCR method only considers four days in summer.
- 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; and
- sometimes, system stress occurs in lower demand intervals where lower available capacity means a lower reserve margin. The current IRCR method does not consider the size of the reserve margin.

There is opportunity to amend the IRCR calculation to better align with system stress periods.

3.2.2 Alternative IRCR Options

EPWA identified five options for determining the IRCR:

1. Equivalent firm capacity, similar to ELCC;
2. Ex-ante notification, where AEMO announces a day or so in advance that certain intervals will be IRCR intervals;
3. Ex-post interval selection based on reserve margin, similar to how the dynamic capacity refund rate is calculated;
4. Ex-post interval selection based on peak load, similar to the current method; and
5. A two-pronged metric, using both base and peak demand.

The options were discussed with the RCMRWG and the MAC. Each option is set out in more detail below.

Option 1: Equivalent Firm Capacity

It would be possible to apply an ELCC-like approach at a participant portfolio level as follows:

1. Using historical load and historical intermittent fleet output adjusted as discussed in section 2.2.3, adjust load up or down to find the load level at which EUE is at the level specified in the Planning Criterion.
2. For each participant:
   - sum all associated loads, resulting in an interval-by-interval demand profile;
   - subtract the interval-by-interval demand profile from the interval-by-interval historical load;
   - increase demand until EUE is at the same level it was in step 1;
   - set the participant's Equivalent Firm Capacity to the MW quantity of demand added.
3. Allocate IRCR in proportion to Equivalent Firm Capacity, so that the total IRCR allocated equals the RCR.

This approach would not be very transparent to consuming participants, as it would not allow a common set of intervals to be used for CRC allocation.

IRCR could be recalculated daily to account for switching.

Option 2: Ex-ante Notification by AEMO

Under this option, IRCR would be allocated based on participant offtake in specific intervals.

AEMO would designate specific upcoming intervals as "performance intervals", with some hours advance notice.

This option would give AEMO flexibility to respond to specific circumstances, but it would need to develop procedures to define how it would use this flexibility. AEMO would be restricted to a certain number of days on which it could designate intervals.

This approach would mean:

- intervals less likely to be designated early in the hot season (as AEMO 'saves up' intervals in case of greater need later) and more likely to be designated later in the hot season (as AEMO is freer to 'use up' remaining intervals);
- different numbers of performance intervals in each year;
- potential for no performance intervals to be called in a mild year; and
- potential for AEMO to call performance intervals based on a load forecast that does not eventuate.

Option 3: Ex-post Intervals by Reserve Margin

Under this option, IRCR would be allocated based on participant offtake in the intervals with the lowest reserve margin.

AEMO would publish reserve margin data.[18] Participants would need to monitor this data and judge whether each interval could potentially affect their IRCR allocation, and whether to reduce demand accordingly.

Given that the projected reserve margin can change at short notice based on facility forced outages (which consumers do not have any control over), consuming participants would need to be more responsive to system conditions to manage their IRCR exposure.

Over time, this method would be likely to identify more intervals in shoulder seasons than a demand-based method. It would also be less predictable than a demand-based method, as historical outage data is less predictive of future outages and fuel supply issues than historical demand data is of future demand.

The method could be made more predictable by excluding forced outages (and potentially planned outages), but consuming participants still have no control over intermittent generation output.

Option 4: Ex-post Intervals by Demand

Under this option, IRCR would be allocated based on participant offtake in the intervals with the highest demand.

This option has the same approach as the current method, but it is possible to adjust the interval selection rule to better capture the pattern of system stress events in the SWIS.

This option would be more predictable than a reserve margin based method, and over time, would be less likely to identify intervals outside the summer hot season.

Option 5: Two-pronged Metric

During the CARWG process, one participant suggested another option, where capacity costs are allocated in two portions to reflect that consumers receive value for reliability outside the peak:

1. one portion relating to demand at peak times, calculated as per the previous options; and
2. a second portion relating to consumption at other times – for example, calculated as the mean demand for the year, or consumption at the time of lowest demand.

This option would mean that participants have less incentive to reduce their demand at peak, but a new incentive to reduce their overall demand.

Assessing the Options

Table 2 provides an assessment of each option against the policy goals.

[18] Firm capacity, plus actual intermittent output, minus demand.

Table 2: Qualitative Comparison of IRCR Approaches[19]

Goal	1. Equivalent firm capacity	2. Ex-ante notification	3. Ex-post by reserve margin	4. Ex-post by demand	5. Two-pronged metric
Capacity payments fully recovered from consumers	●	●	●	●	●
Allocates costs based on contribution to the RCR	●	◕	◕	●	◔
Provides a signal to amend electricity use in a way that reduces the RCR	●	◕	◕	●	◕
Allows costs to be allocated to new loads added during a capacity year	●	●	●	●	●
Simple, cost effective, and easy to understand	◑	●	◕	●	◕
Aligns with CRC methodology	◑	◕	◕	◕	◔
Minimises year to year volatility	◑	◑	◑	◑	◕
Can be replicated by potential investors and other stakeholders	◑	◔	●	●	◕
Is predictable so it incentivises effective load management during system stress events	◑	◔	◑	◕	◕

All options allow capacity payments to be fully recovered from consumers, and all can account for new loads being added during a capacity year.

The RCR is set according to the Planning Criterion. Options 1 and 4 come closest to allocating costs by consumer contribution to the RCR. Options 2 and 3 are less directly related to the way the RCR is calculated, and so the signal they provide is less likely to result

19 A complete circle indicates that the option fully achieves the goal, an empty circle indicates that the option does not achieve the goal at all, and a partial circle indicates that the option partially achieves the goal.

in a reduction in the RCR. Option 5 allocates only part of the costs by contribution to the RCR.

Options 2 and 4 are both relatively simple, while option 1 is the most complex. Options 3 and 5 fall in between. Options 3 and 4 are the easiest for stakeholders to replicate.

Option 1's ELCC-like calculation is aligned with the fleet portion of the intermittent generation methodology but would not provide intervals to be used in allocating the Fleet ELCC across individual facilities (as discussed in section 2.2.3. All other options would provide a set of intervals which could be used in the CRC methodology.

With a single year lookback, all methods are likely to have some volatility, but only insofar as consumption profiles are volatile.

Option 4 should be reasonably predictable, while ex-ante notification would be most difficult to forecast for a future year.

Option 5 would dilute the incentive for participants to manage their consumption at times of system stress and is not aligned with a causer-pays philosophy.

The MAC supported continuing to use contribution to load in high demand intervals as the basis for setting IRCR.

Proposal A:

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

Consultation Questions:

(1) Do stakeholders support determining IRCR based on contribution to high demand intervals?

3.2.3 Characteristics of High Load Periods

While participant consumption during high demand intervals reflects their contribution to the RCR, the current IRCR selection methodology does not necessarily select the relevant system stress intervals.

How many Intervals are Peak Intervals?

Figure 2 shows the load duration curve (LDC) [20] for each capacity year[21] from 2015 to 2021. Figure 3 zooms in to the top 25 intervals. Figure 2 and Figure 3 show that the shape of the LDC differs between years. For example, in 2017, 2019 and 2020, there are only a few very high load intervals, with several hundred MW difference in demand between the highest interval and the tenth highest interval. In other years the drop-off is not as steep, but in most years, the load drops off significantly somewhere between the 5th and 20th interval. This indicates that the current figure of around 12 intervals remains reasonable.

20 Total Sent Out Generation. There was no load curtailment or lost load in these intervals.

21 8am 1 October through 7.59am the following 1 October.

Figure 2: Load Duration Curves for 2015-2021

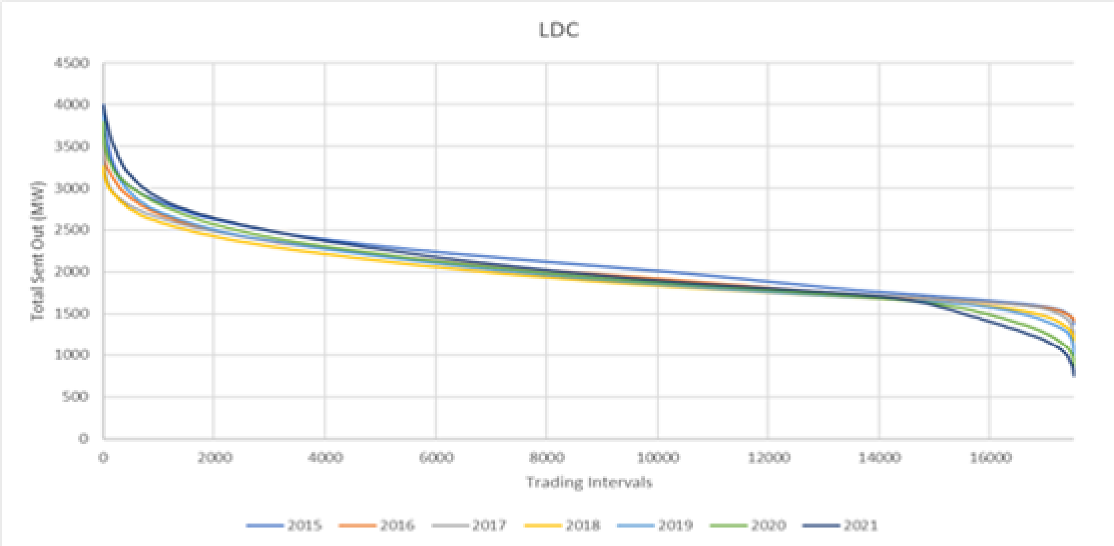
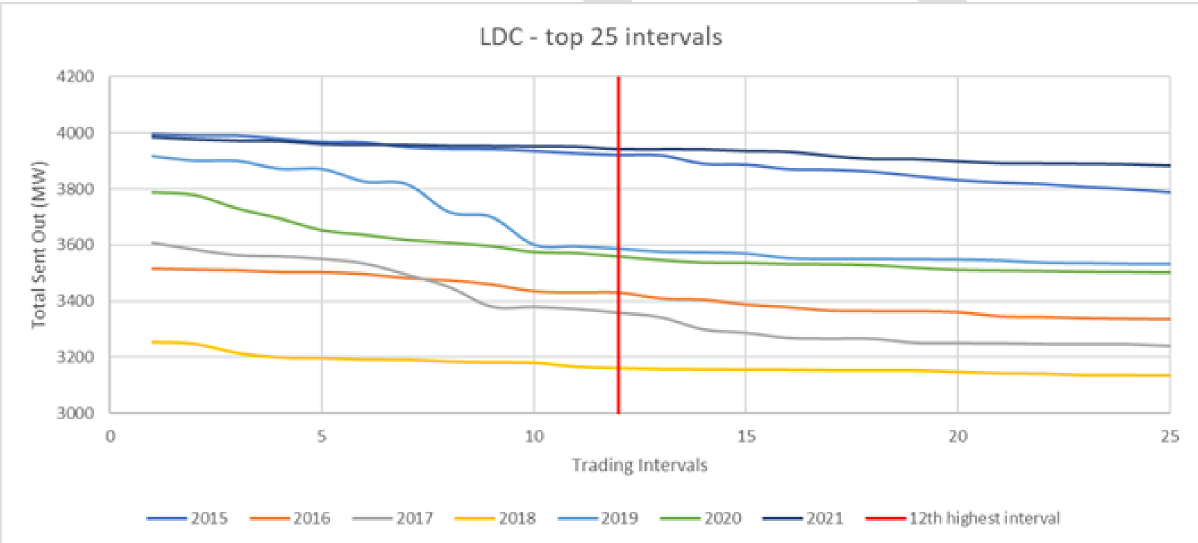


Figure 3: Load Duration Curves for 2015-2021 – top 25 Intervals



How Many Days are Peak Days?

Figure 4 shows how many days the top 12 intervals fell on in each year. Figure 5 shows the number of intervals on each of the relevant days.

In 2015, 2016, 2017 and 2020, the peak Trading Intervals fall only on two days. In other years, the highest demand periods are distributed over a wider range of days, especially in 2021 where they occur on six different days.

All peak intervals were experienced in the Hot Season except for one interval in 2018 (highlighted in red).

Figure 4: Number of Days on which the Top 12 Demand Intervals Fall

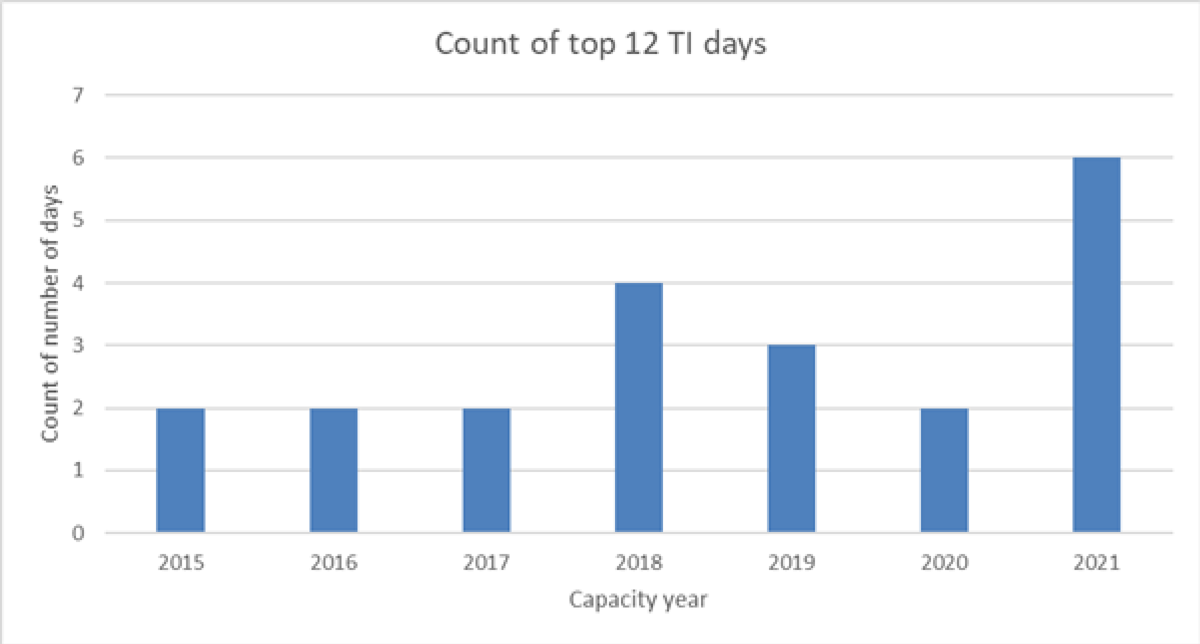
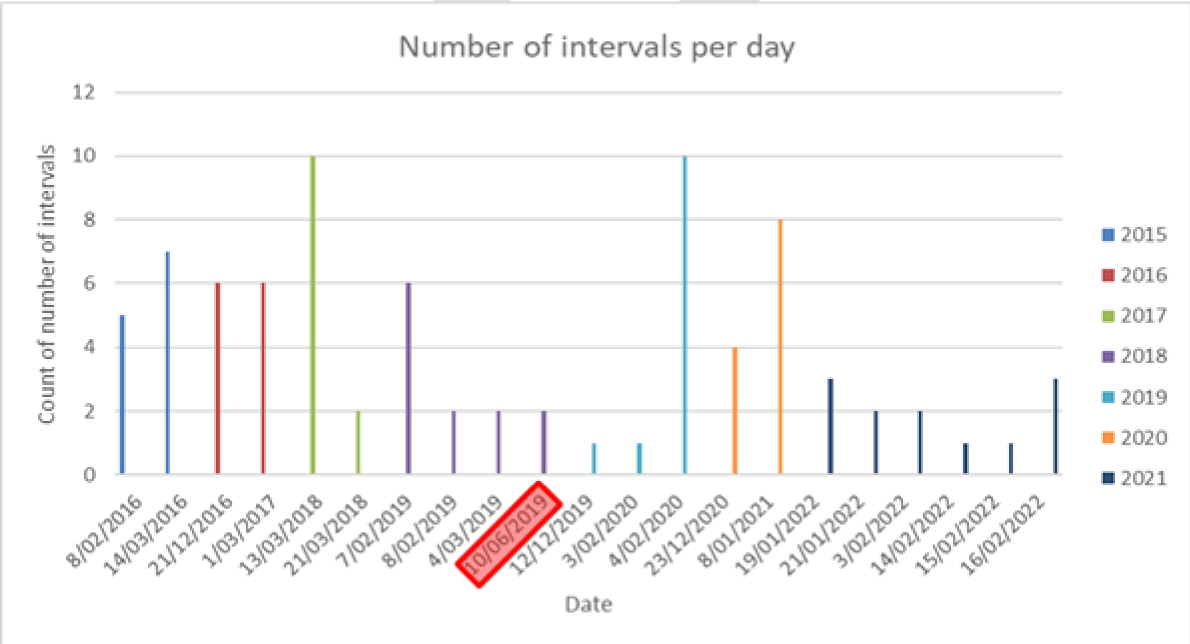


Figure 5: Number of Peak Intervals Falling on Each Day



The shape of the load on the peak demand days varies. For example:

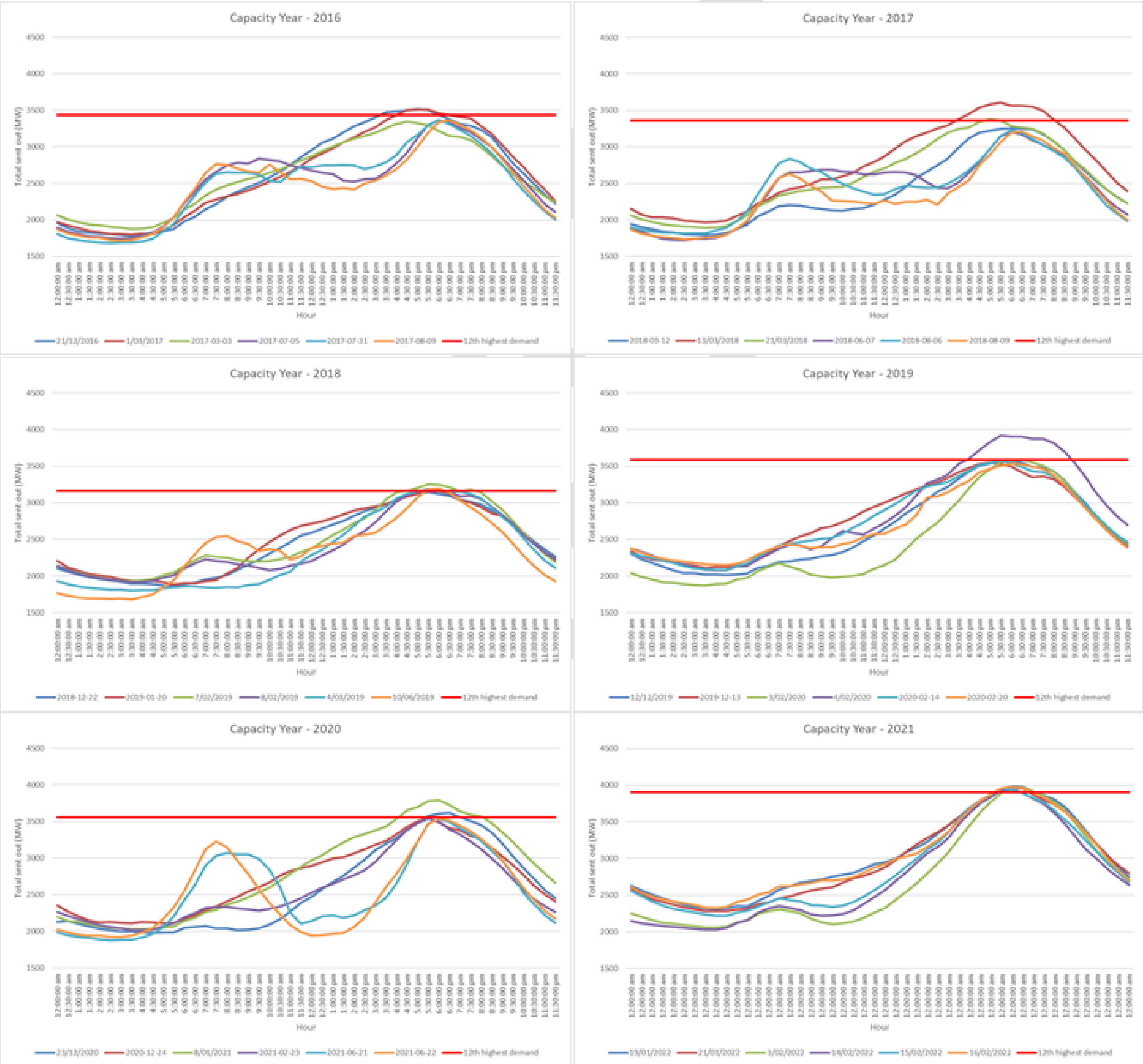
- In Capacity Year 2017 and 2019, 10 of the 12 highest load intervals occurred on a single day;
- In 2018 and 2021, there were several days with similarly high levels of load; and
- In 2016 and 2020, some days had both morning and evening peaks, while in 2019 and 2021 none of the peak days had significant morning peaks.

The current IRCR method would select only three intervals from the highest demand days, even if they have higher demand than intervals chosen on other days.

Selecting a minimum of four days each year regardless of the load differential between those days would mean that the IRCR is based on time periods where there is no significant system stress. MAC members expressed concern that reducing the number of days selected will make it more difficult for consumers to manage. EPWA recognises that reducing the minimum to one or two days would increase the difficulty for consumers to manage, but considers that three days would allow more consistent incentive for response to the IRCR signal.

Figure 6 has six charts showing the load on the six days with the highest peak demand for each year 2016 – 2021. The red line in each chart shows the load in the 12th highest interval for the year.

Figure 6: Load Profile on Peak Demand Days



Are Peak Intervals Always Contiguous?

Table 3 shows how the top 12 demand intervals fall across the relevant days. All intervals fall in the afternoon or evening, and form a contiguous block on each day, except for one day in CY 2018, where the load dips slightly in one interval before returning to a higher quantity. Participant behaviour in that interval is also indicative of their contribution to the RCR.

Table 3: Occurrence of Peak Intervals on Peak Days

Capacity Year	2015		2016		2017		2018				2019			2020		2021					
Day	**1**	**2**	**1**	**2**	**1**	**2**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**1**	**2**	**1**	**2**	**3**	**4**	**5**	**6**
3:30 pm			1		1																
4:00 pm		1	1	1	1								1								
4:30 pm	1	1	1	1	1		1						1		1						
5:00 pm	1	1	1	1	1	1	1						1		1						
5:30 pm	1	1	1	1	1	1	1	1	1	1	1		1	1	1	1				1	1
6:00 pm	1	1	1	1	1		1	1	1	1			1	1	1	1	1	1	1		1
6:30 pm	1	1		1	1		1					1	1	1	1	1	1	1			1
7:00 pm		1			1								1	1	1						
7:30 pm					1		1						1		1						
8:00 pm					1								1		1						
8:30 pm													1								

Is the Whole Year Relevant?

In mild years, with a relatively low summer peak demand, or in years where there is a single high demand event, it is possible that some of the top intervals may fall in winter, as is the case in 2018, the year with the lowest peak demand in the sample. However:

- these intervals do not represent stress events, and the demand is not reflective of a 1-in-10 year peak;
- the SWIS currently experiences extreme peak demand only in the summer period, therefore facility generation or consumption in the summer period is the most important factor. There is currently limited benefit in sending a signal for loads to reduce the peak load during winter; and
- focusing generation and load incentives on the hot season period would increase predictability for participants.

EPWA therefore proposes to retain the restriction on IRCR intervals to the December-March period. This restriction should be revisited if winter peak values start to approach the extremes seen in summer in a 1-in-10 peak year.

Proposed Interval Selection Methodology

The proposed IRCR interval selection methodology is 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 summer 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) 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

Table 4 shows the results of this method compared to the current IRCR intervals for capacity year 2017. The demand column is shaded to indicate the highest demand intervals in red. Other years are shown in Appendix C.

Table 4: Capacity Year 2017 IRCR Intervals – Current vs Proposed

Date	Time	SOG (MW)	Proposed Intervals	Current Intervals
15/02/2018	5:00 pm	3172.2	✓	✓
15/02/2018	5:30 pm	3195.6		✓
15/02/2018	6:00 pm	3164.6		✓
12/03/2018	5:30 pm	3247.8	✓	✓
12/03/2018	6:00 pm	3251.5	✓	✓
12/03/2018	6:30 pm	3248.6	✓	✓
13/03/2018	2:30 pm	3252.7		
13/03/2018	3:00 pm	3300.3		
13/03/2018	3:30 pm	3380.7	✓	
13/03/2018	4:00 pm	3451.6	✓	
13/03/2018	4:30 pm	3536.1	✓	
13/03/2018	5:00 pm	3585.6	✓	✓
13/03/2018	5:30 pm	3609.5	✓	✓
13/03/2018	6:00 pm	3565.7	✓	✓
13/03/2018	6:30 pm	3561.2	✓	
13/03/2018	7:00 pm	3552.5	✓	
13/03/2018	7:30 pm	3496	✓	
13/03/2018	8:00 pm	3373.5	✓	
13/03/2018	8:30 pm	3266.7		
21/03/2018	4:00 pm	3267.3		
21/03/2018	4:30 pm	3343.6	✓	✓
21/03/2018	5:00 pm	3382.1	✓	✓
21/03/2018	5:30 pm	3360.2	✓	✓
21/03/2018	6:00 pm	3288.4		
21/03/2018	6:30 pm	3270.0		

The MAC supported this approach to selecting IRCR intervals for the peak capacity product.

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.

Consultation Questions:

(2) Do stakeholders support the proposed interval selection methodology?

3.2.4 Temperature Dependence

The current IRCR method provides different treatment for TDLs and NTDLs. To qualify as an NTDL, consumption during the 4 peak demand intervals in each of 9 previous months must have a median greater than 1 MWh and must be narrowly distributed around the median.

An NTDL receives a lower IRCR than an otherwise equivalent TDL, on the basis that it has relatively flat load, which has little variation between peak and off-peak periods. This could be seen as conceptually similar to the runway method for allocating spinning reserve, associating the 'first MW' of capacity with NTDLs, and the 'last MW' of capacity requirement to more variable loads. However:

- each MWh of usage at peak times has an equivalent contribution to the RCR;
- the types of loads that can qualify as NTDL are also likely to be the types of loads that can adjust their consumption during IRCR intervals, meaning that such loads already have an opportunity to manage their exposure to capacity charges;
- the multiplier reduces the incentive for a participant to make its consumption flexibility available to market dispatch by participating as a DSP; and
- the NTDL/TDL process is non-trivial for participants and AEMO to manage.

Further, as discussed in section 3.3, flat loads do not contribute to the need for flexible capacity, so the proposed IRCR approach for flexible capacity will inherently allocate low (or no) cost to a load with flat consumption profile.

The MAC and RCMRWG supported removing the distortionary effect of TDLs and NTDLs on cost recovery, to level out the treatment of large and small loads.

Proposal C:

Remove TDL/NTDL multipliers from the IRCR process.

Consultation Questions:

(3) Do stakeholders support the removal of TDL and NTDL multipliers?

3.2.5 Treatment of New Loads

Loads have different characteristics to generators:

- their demand profile is more likely to change over time;
- their demand profile is more likely to be volatile;
- there are many more of them;
- they are likely to commission frequently at all times of the year; and
- they are likely to change ownership (or responsible party) more frequently, including during the capacity year.

This means that a participant's IRCR must be able to change throughout the year, to account for commissioning and ownership changes. For existing loads, switches can be accounted for either by recalculating the IRCR each day, or by multiplying the demand by the proportion of the month (or week) that each participant was responsible for the load.

However, when a load first commissions or installs TOU metering, there will not be a record of its load during the selected intervals in the previous capacity year. As a proxy, the current IRCR methodology uses the demand of the new load during the four peak intervals of month n-3. These intervals are unlikely to be reflective of actual system stress, particularly where month n-3 falls in the winter or spring, and in those months will underestimate hot season demand for most loads.

Alternatively, the IRCR process could use:

- average load across all meters;
- historical maximum consumption or maximum allowed network offtake as held in standing data; or
- historical maximum load.

Using average demand of other loads would not appropriately account for the different sizes of load. Using historical maximum consumption or allowed offtake would overestimate the contribution of many loads if that consumption is not correlated with the overall demand profile.

Instead of using the median demand in the four peak intervals of month n-3, EPWA proposes to use the maximum of the median demand in the four peak intervals of any prior month.

The notional wholesale meter would continue to have a 'new' component based on non-interval meter growth, but the median notional wholesale meter would be based on load in the relevant hot season intervals.

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.

Consultation Questions:

(4) Do stakeholders support the changes to the treatment of new loads?

3.3 IRCR for Flexible Capacity

The cost of procuring flexible capacity will be recovered from Market Participants, and should be recovered in accordance with the principles set out in section 3.1.

Recovery is only necessary where there is additional cost over and above the cost of procuring peak capacity. In situations where there is no price premium for flexible capacity, all capacity costs will be recovered through the peak product. The flex IRCR calculation is therefore only relevant where additional expenditure is required to attract flexible capacity.

As noted in section 2.1.3, the RCR for flexible capacity will be set based on AEMO's forecast of the largest expected system ramp in the relevant capacity year. This means that the key driver of the RCR for flexible capacity is the shape of the load, and the extent to which there is a rapid and sustained change in intra-day demand.

3.3.1 Options for Setting Flexible IRCR

Options

There are two main options for determining IRCR for flexible capacity product:

(1) Use the same calculation as used for peak IRCR, but scaled to the different RCR. That is:

FlexIRCR = PeakIRCR * (Flex RCR / Peak RCR)

Under this approach, participants would pay the same proportion of costs for both peak and flexible capacity.

(2) Calculate Flexible IRCR based on the contribution to the flex RCR. Under this approach, the shape of each load would determine its IRCR; specifically, a load's historical contribution to periods of steep ramping would drive its IRCR:

(a) flat loads (which do not contribute to the RCR) would have a low or zero IRCR;

(b) loads which decrease consumption during high ramp periods would also have a low or zero IRCR; and

(c) loads which increase consumption lot during high ramp periods would have a relatively high IRCR.

Assessing the Options

Table 5 provides an assessment of each option against the policy goals.

Table 5: Qualitative Comparison of Flexible IRCR Approaches

Goal	1. Peak IRCR	2. Contribution to High Ramp Periods
Capacity payments fully recovered from consumers	●	●
Allocates costs based on contribution to the RCR	○	●
Provides a signal to amend electricity use in a way that reduces the RCR	○	●

Goal	1. Peak IRCR	2. Contribution to High Ramp Periods
Allows costs to be allocated to new loads added during a capacity year	●	●
Simple, cost effective, and easy to understand	●	◕
Aligns with CRC methodology	◔	◕
Minimises year to year volatility	◑	◑
Can be replicated by potential investors and other stakeholders	●	●
Is predictable so it incentivises effective load management during system stress events	●	●

Option 1 would be simple to implement but would not provide an incentive to participants to reduce their contribution to the evening ramp.

Option 2 would be more complex to implement, but would provide that incentive.

Both options allow capacity payments to be fully recovered from consumers, and can account for new loads being added during a capacity year.

The RCR is set according to the Planning Criterion. Option 2 allocates costs in alignment with consumer contribution to the RCR but Option 1 does not.

While Option 1 is very simple, option 2 is not much more complicated. Both methods can be replicated by external participants using publicly available data, and can be predicted in advance with some confidence.

Option 2's approach is better aligned with the CRC allocation approach for flexible capacity, as it relates to performance during key periods. Option 1 would assign IRCR based on consumption during peak periods, which does not relate to the criteria used for flexible CRC allocation.

With a single year lookback, both methods are likely to have some volatility, but only insofar as consumption profiles are volatile.

The MAC considered that Option 2 best complements the way the flexible RCR is set.

Proposal E:

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

Consultation Questions:

(5) Do stakeholders support determining flexible IRCR based on consumer contribution to the ramp during high ramp periods?

3.3.2 Characteristics of High Ramp Days

When do High Ramp Periods Occur?

In the summer season, load is generally high throughout the day, as air-conditioning load runs continuously. In the shoulder seasons, load is lower in the daytime, and behind the meter solar declines earlier, resulting in a steeper ramp in the afternoon and evening, albeit to a lower peak.

Figure 7 shows how many of the top four high ramp days fall in each month of the year. In all years from 2015-2021, all the highest ramps occur between June and September.

Figure 7: Timing of High Ramp Days

Figure 8 shows the distribution of maximum daily ramps for each capacity year from 2015 to 2021, and Figure 9 zooms in on the top 20 days.

Figure 8: Maximum 4-Hour Ramp Rate Distribution

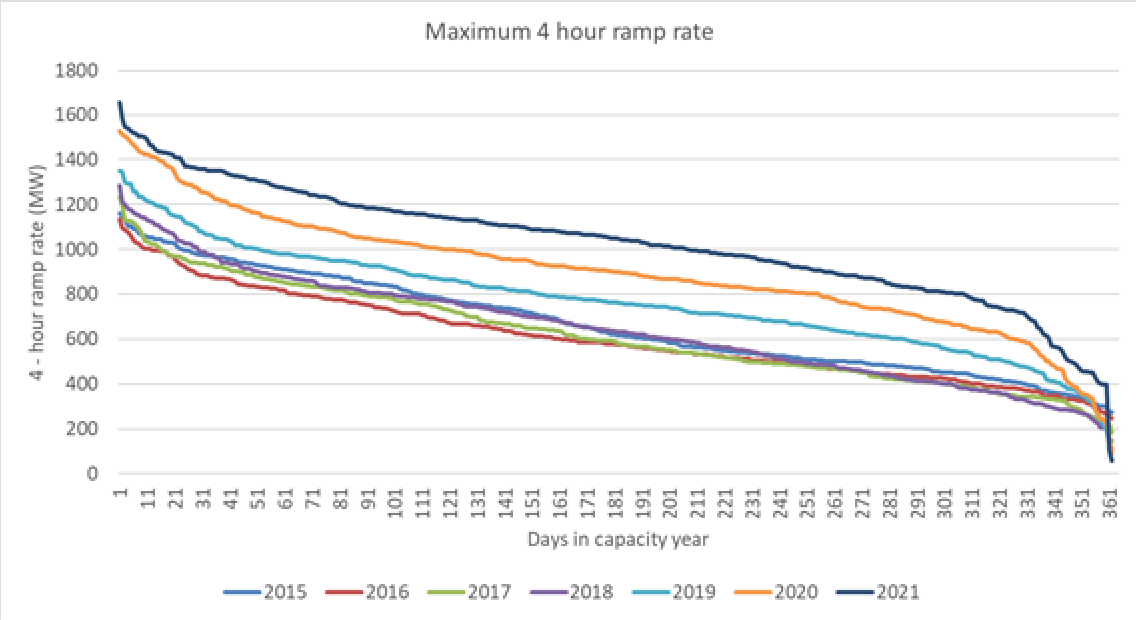
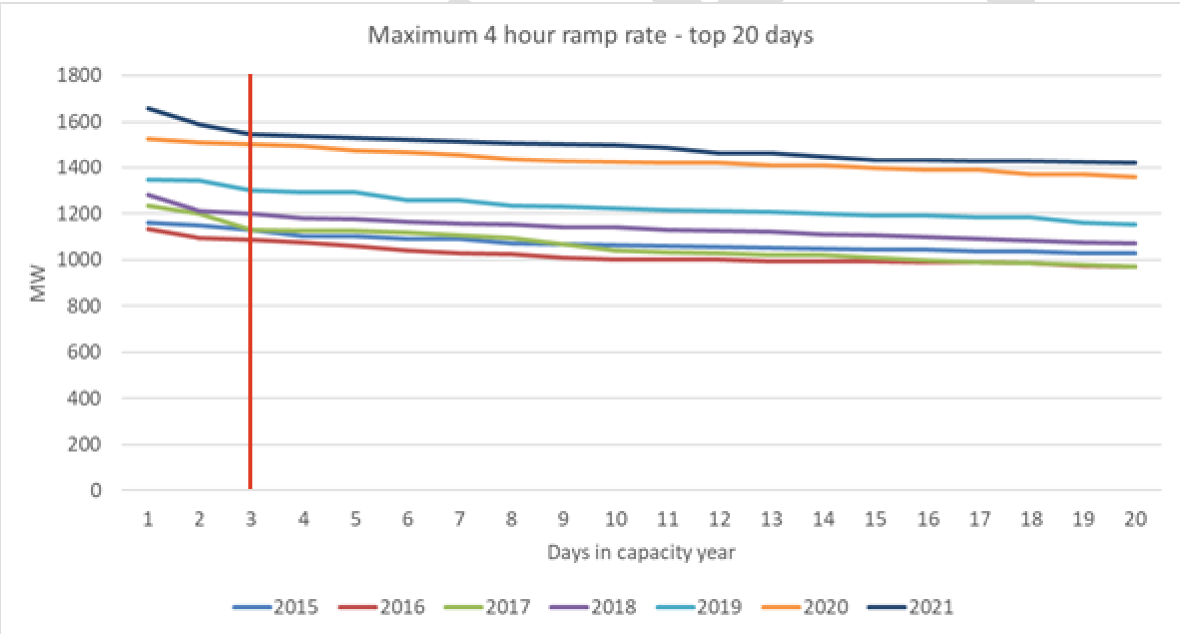


Figure 9: Maximum 4-Hour Ramp Rate Distribution – Top 20 Days



In some years (e.g. 2017, 2018 and 2021), the highest ramp day is significantly steeper than other days, while in other years, the maximum daily ramp falls off more slowly.

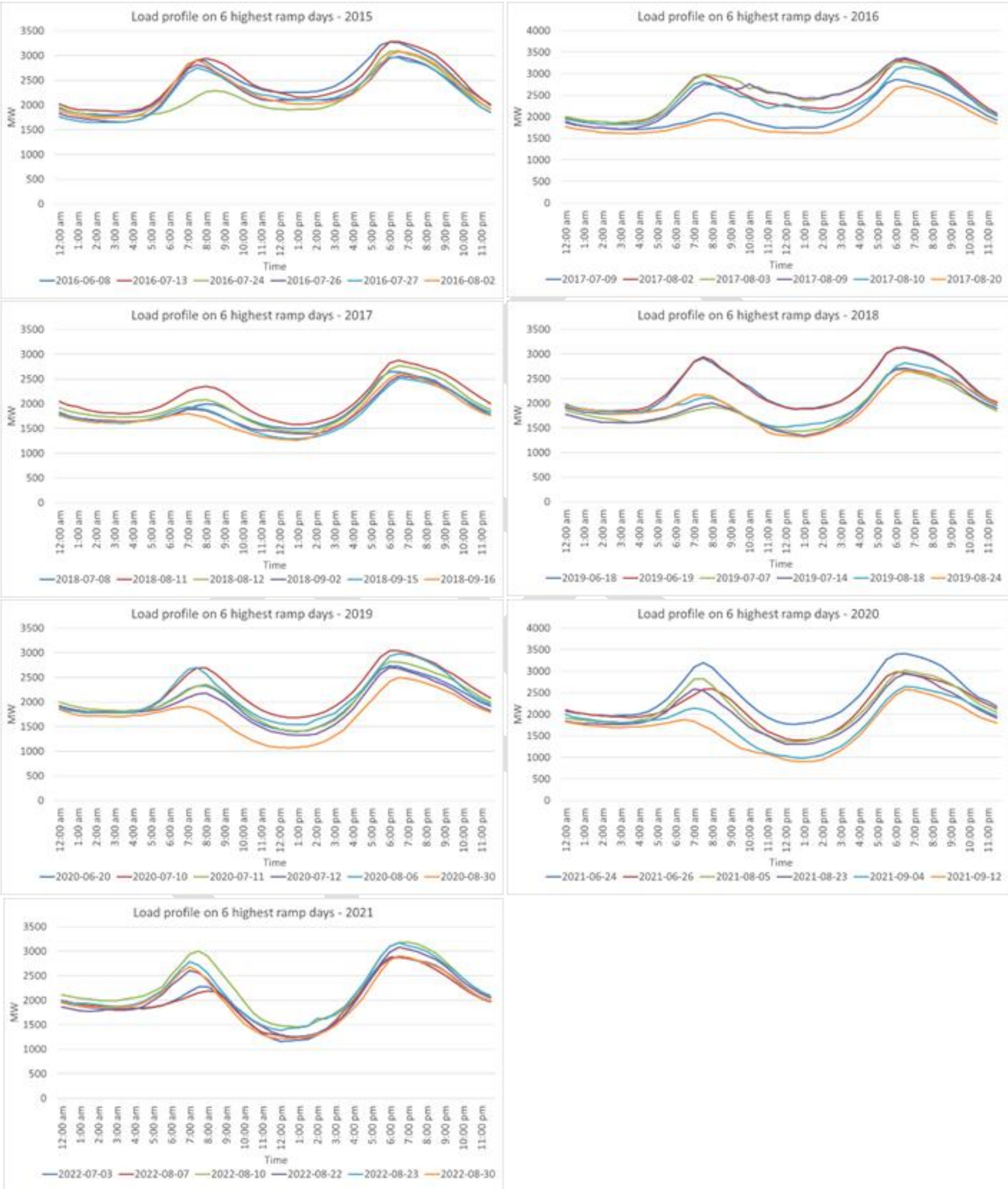
While the flexible RCR will be set based on the highest single ramp expected in the year, the IRCR methodology will look backwards. Using a single day would be difficult for consumers to manage, so it is reasonable to use more than one day.

In line with the peak IRCR calculation, EPWA proposes to use the three days with the highest ramp.

How Long Does a High Ramp Period Last?

Figure 10 shows the load shape for selected high ramp days. From the end of the midday trough through to the peak is generally around 4 hours, though it can be longer or shorter depending on the day.

Figure 10: Load Profile on Top 6 Highest Ramp Days



What Time of Day do High Ramp Periods Occur?

Table 6 shows when the high ramp period occurred on the highest ramp days. Until capacity year 2016, some of the highest 4-hour ramps were observed in the morning. Since 2017, they all occur in the lead up to the evening peak. This pattern is expected to continue with increasing penetration of distributed solar PV generation.

It does not appear necessary to restrict the steepest ramp to a particular time of day.

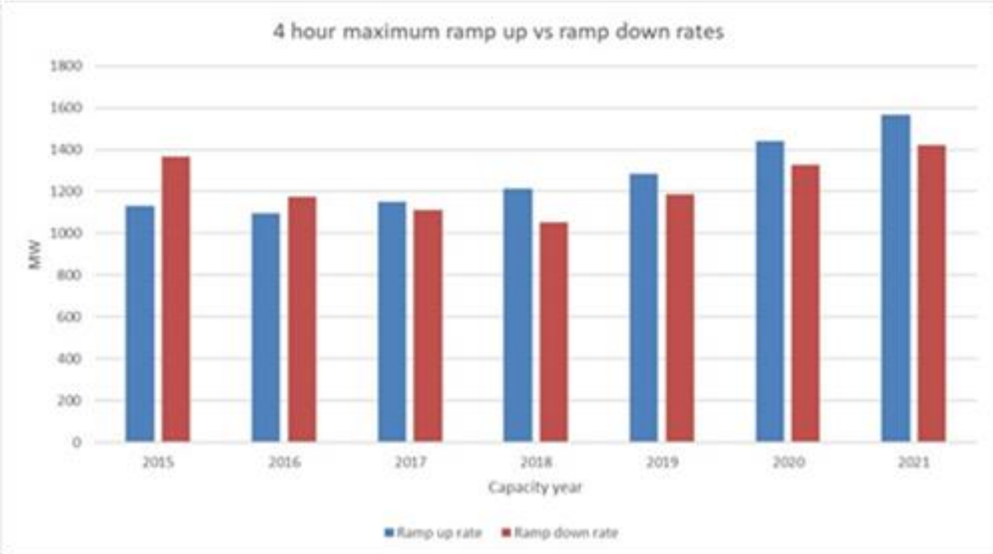
Table 6: Times of day for High Ramp Periods

Hours Making up the Highest Ramp Requirement							
Time of the day/Capacity year	2015	2016	2017	2018	2019	2020	2021
3:30 am	2	1					
4:00 am	2	1					
4:30 am	2	1					
5:00 am	2	1					
5:30 am	2	1					
6:00 am	2	1					
6:30 am	2	1					
7:00 am	2	1					
7:30 am	2	1					
2:00 pm	1	1	1	4	3	2	2
2:30 pm	2	3	4	4	4	4	4
3:00 pm	2	3	4	4	4	4	4
3:30 pm	2	3	4	4	4	4	4
4:00 pm	2	3	4	4	4	4	4
4:30 pm	2	3	4	4	4	4	4
5:00 pm	2	3	4	4	4	4	4
5:30 pm	2	3	4	4	4	4	4
6:00 pm	2	3	4	4	4	4	4
6:30 pm	1	2	3		1	2	2

Is Downward Ramp Relevant?

Figure 11 shows the size of the largest four-hour upwards and downwards ramps for each capacity year from 2015 to 2021.

Figure 11: Maximum Ramp Up vs Ramp Down Comparison



In 2015 and 2016, the maximum downward ramp was higher than the maximum upwards ramp. Since 2017, the ramp up requirement has been higher, scaling with increased penetration of distributed generation.

EPWA proposes to use ramp up as the relevant metric for the flexible capacity product, because:

- 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 solar PV facilities, while solar facilities are not available at the end of the evening upwards ramp.

Proposed Method for Flexible Capacity IRCR

The proposed flexible capacity IRCR selection methodology is 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 (t) and the load at the end of the Trading Interval four hours prior (t-8).

(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 the seven prior Trading Intervals.

(4) For each participant load portfolio:

  (a) calculate the facility ramp contribution for each day selected in step (2), as the difference between consumption at the start of the earliest selected trading interval and the end of the latest selected trading interval; and

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

(5) Calculate scaling factor R as the Flex RCR divided by the sum of all facility annual ramp contributions.

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

The flex IRCR will be recalculated daily to account for switching and new loads.

This approach aligns with the approach used for the peak IRCR, while reflecting the different nature of the flexible capacity requirement.

Appendix C shows which intervals would be selected under this rule for each year 2015-2021.

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.

Consultation Questions:

(6) Do stakeholders support the proposed interval selection rule?

(7) Do stakeholders agree that it is necessary for AEMO to publish the forecast ramp?

4. Demand Side Programmes

4.1 Introduction

DSPs are a mechanism for loads to participate in the RCM. The current design is geared to large industrial loads and is not appropriate for the aggregations of smaller loads that are expected to progressively enter the market. There is also an opportunity to align with the changes to CRC for intermittent generators and to IRCR.

Chapter 4 discusses the approaches to CRC allocation and dispatch for DSPs. Consequential changes to the testing, outages, and refund regimes are covered in Chapter 5.

4.2 DSP CRC

CRC allocation for DSPs needs to be performed ahead of time (as it is for generators) rather than being assessed during the capacity year, so that it can be accounted for during the capacity certification process.

EPWA is seeking an approach to assessing DSP CRC that:

- ensures that the system reliability objective is met;
- adequately assesses facilities' contribution to system reliability;
- minimises year-to-year volatility for investors;
- is simple and easy to understand;
- ideally can be replicated by potential investors and other stakeholders; and
- aligns with CRC methodology for intermittent generators.

4.2.1 Current Approach

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

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

Participants can request 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 market, as noted in Rule Change Proposal RC_2019_01. Participants with such flexible load can reduce their IRCR exposure by managing their own load behind the meter and have limited incentive to include it in central market scheduling.

This approach also differs from the approach used to set IRCR and intermittent generation.

4.2.2 Alternative Options for DSP CRC Allocation

EPWA identified three options for allocating DSP CRC that align with the selected IRCR and intermittent generation CRC methods:

1. using an ELCC approach (either by fleet or individually);
2. basing the CRC on load in historical IRCR intervals; or
3. having the DSP proponent nominate a CRC, accompanied by evidence that there will be sufficient load associated with the programme to deliver that CRC at expected dispatch times.

Option 1: ELCC

The overall contribution of registered DSPs to system reliability could be assessed in the same way as intermittent generators:

(1) using historical load, find the load at which EUE is at the Planning Criterion target level;

- adjust the historical for DER penetration and any load curtailment (e.g. DSP dispatch, unserved energy, or NCESS dispatch), and historical intermittent fleet output (adjusted for involuntary curtailment);

(2) for each DSP, identify available curtailment in each interval in the previous capacity year.

(3) adjust the historical load trace to subtract available DSP curtailment.

(4) increase load until EUE is the same as it was in step (1_.

The added load in step (4) is then the DSP ELCC.

Alternatively, a DSP Fleet ELCC could be allocated to individual DSPs based on their available curtailment in the same intervals used for IRCR.

The ELCC approach (whether at fleet or facility level) is less appropriate for DSPs than for supply side facilities, as loads have different operating constraints than generators. In particular, while intermittent generators generally seek to output as much energy as possible, the consumption at each load is driven by a range of factors, none of which involve consuming as much as possible.

Option 1 also relies on historical consumption being a good indicator of future consumption.

Option 2: Determine DSP CRC Based on IRCR Intervals

DSP CRC levels could be allocated based on median consumption in the same intervals used to determine IRCR.

This approach would mean a more even balance between a participant's incentives to minimise IRCR (by having low load at times of system stress) and maximise DSP CRC (by having high load at times of system stress that can then be curtailed).

Option 2 would not account for synergies or antagonisms between the load profiles of different DSPs.

Option 2 is most suited where historical consumption is a reliable indicator of future consumption – such as for large industrial loads with a relatively flat consumption profile. Where a DSP's associated loads are likely to change from year-to-year, this method is open to potential gaming by selecting loads based on their performance in the previous year only.

Option 3: Participant Nominated CRC

Participants could be made responsible for determining the quantity of reduction by having DSP proponents nominate a performance level for the DSP – the MW of load response it commits to provide, when called.

Historical load data would not be used to directly set the CRC level, but the participant would need to show evidence that it will have sufficient associated load to deliver the nominated reduction – this would be confirmed through reserve capacity testing.

The DSP would need to pay immediate refunds upon failure to provide the nominated level when dispatched or tested to provide incentive to ensure the programme can deliver the nominated reduction.

Option 3 would be appropriate for aggregations of multiple small loads, particularly where the associated loads are likely to change from year to year, and would allow programme owners more leeway to manage their fleet of Associated Loads over time.

Assessing the Options

Table 7 provides an assessment of each option against the policy goals.

Table 7: Qualitative Comparison of Approaches to Allocate CRC to DSPs

Goal	1. ELCC	2. IRCR Intervals	3. Nomination
Ensures that the system reliability objective is met	◕	◕	●
Adequately assesses facilities' contribution to system reliability	◕	◕	●
Minimises year-to-year volatility for investors	◑	◕	●
Is simple and easy to understand	◑	◕	●
Ideally can be replicated by potential investors and other stakeholders	◑	●	●
Aligns with CRC methodology for intermittent generators	◕	◕	◑

All options ensure system reliability is met, although options 1 and 2 only if historic data is a good indicator of future performance.

Options 1 and 2 could overestimate the quantity of reduction that is available from a DSP if future load is not correlated with past load, but would better align DSP incentives with those provided by IRCR and intermittent CRC processes.

Option 3 gives participants the control over changes in CRC from year-to-year

Option 3 is the easiest to understand and replicate, while option 1 is the most complex and difficult to replicate.

Options 1 and 2 are closer to the method to be used for intermittent generation CRC, while option 3 is more like the approach used for schedulable generation.

All options would rebalance the incentive for participants to make demand flexibility available for dispatch via a DSP rather than just controlling it themselves via IRCR.

4.2.3 Proposed Method for DSP CRC

EPWA considers that the different characteristics of different loads mean that it is appropriate to use different methods for different types of DSPs. In particular:

- For DSPs with large industrial loads, the specific NMIs involved will be clearly identifiable at the time of certification, several years before the actual delivery of the capacity service, and will not change from year-to-year. These DSPs can be certified based on historical demand data.
- 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.

This approach allows historical data to be used where it can be relied on for DSPs with large industrial loads, while putting the onus on aggregators to “overfill the programme” to provide evidence that they have sufficient load to curtail when needed.

RCMRWG participants expressed concern about the potential cost of having two methods to allocate CRC to DSPs, and that three may not be a sizable of the pool of potential flexible loads.

EPWA considers that the effort is substantially the same for both approaches, with the same outage, testing and refund arrangements. The WEM Rules already contemplate Associated Loads changing during the year, and systems to add and subtract Associated Loads to and from DSPs are already required. Where the IRCR is to be used for DSP certification, it will have already have been calculated, and the participant nomination allows the proponent to manage the risk of uncertain output. Given the future importance of demand side response from aggregated loads, the RCM needs to change to reduce barriers to using this important resource.

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.

Consultation Questions:

(8) Do stakeholders support the proposed DSP CRC allocation method?

4.2.4 Consumption Deviation Applications

Historical load (both system wide and for each Associated Load) must be adjusted to remove the effects of AEMO dispatch, just as intermittent facility output data is adjusted to remove the effects of involuntary curtailment.

However, the current DSP CRC allocation approach allows participants to nominate specific intervals as being affected by an AEMO instruction, or by maintenance, and to have those intervals excluded from the CRC assessment. This is roughly equivalent to how generation facilities are assessed a Reserve Capacity Obligation Quantity (RCOQ) of zero when on an approved planned outage, but without the same outage approval process.

Excluding these maintenance intervals from consideration is inconsistent with the treatment of other facilities. Planned outages of schedulable generation 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.

EPWA proposes to remove consumption deviation applications for DSPs, and instead adjust consumption records where necessary using AEMO records of DSP dispatch (including testing).

Proposal H:

Remove Consumption Deviation Applications (CDAs) from the assessment of DSP CRC.

Consultation Questions:

(9) Do stakeholders support the removal of CDAs?

4.2.5 Including Hybrid Facilities in DSPs

Some facilities may have load co-located with generation or storage. A connection point will only be eligible to be an Associated Load of a DSP if its generation or storage is smaller than the de-minimis registration threshold under clause 2.29.4 and 2.29.4A.

Where a participant has both load and storage at a single location, and the storage is not required to be registered, the site could choose to be an Associated Load of a DSP. If the storage was of a size required to register, the site could participate in the RCM as a Capability Class 2 Facility.

Where a participant has both load and intermittent generation at a single location, the magnitude of potential injection would determine whether the site could participate in the RCM as part of a DSP or whether it would need to be registered as a Capability Class 3 facility.

Rules will be needed to ensure that a Capability Class 2 facility with collocated load and storage cannot self-discharge its storage so as to reduce its IRCR exposure while also receiving capacity credits for that capability. This will be addressed through EPWA’s review of Demand Side Response participation in the WEM.

Proposal I:

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

Consultation Questions:

(10) Do stakeholders agree that sites with generation or storage should be able to be part of a DSP?

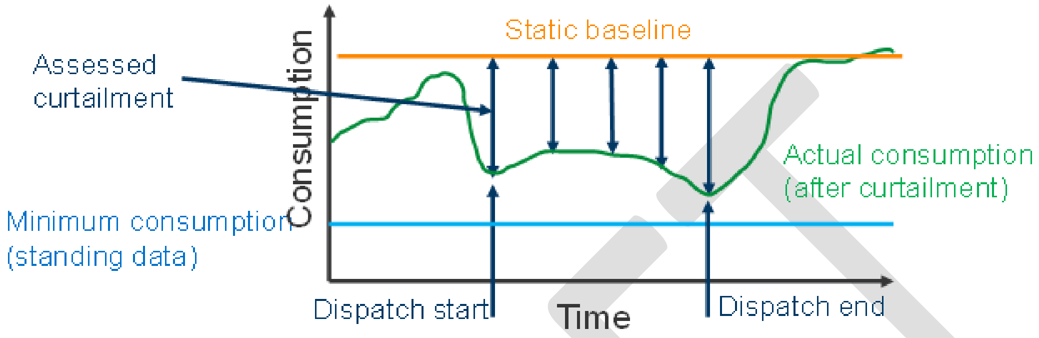
4.3 DSP Dispatch

DSPs are scheduled and dispatched differently from generation facilities. Their nature as a last-resort 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 discussed in section 4.2.1. Figure 12 shows an example of this measurement during a period that the DSP has been dispatched.

Figure 12: DSP Dispatch with a Static Baseline



The Relevant Demand used for dispatch is calculated based on demand in the previous Capacity Year, and is uniform for all Trading Intervals, changing only where a DSP's Associated Loads change.

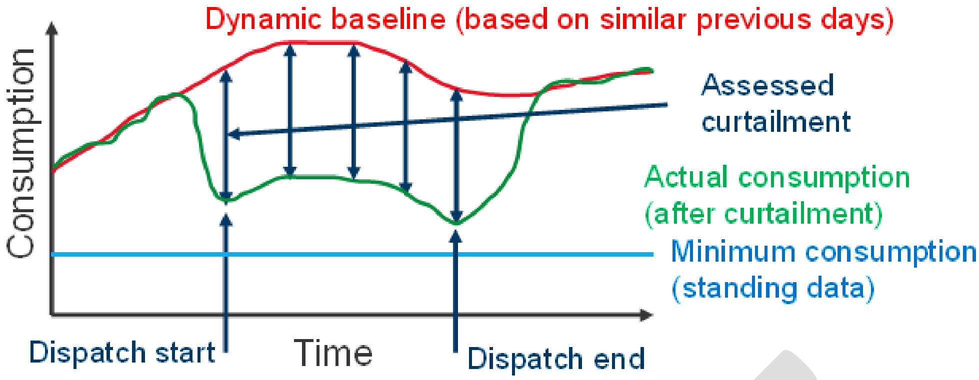
This approach can accurately represent the contribution of loads with a relatively flat consumption profile over several years, where the static baseline accurately reflects the counterfactual consumption.

However, 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 security; 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 that can vary from Trading Interval to Trading Interval can better reflect the contribution of load with a variable consumption profile. Figure 13 shows an example of a dynamic baseline.

Figure 13: DSP Dispatch with a Dynamic Baseline



A dynamic baseline more accurately reflects the actual curtailment delivered by the DSP compared to if it were not called. A dynamic baseline also allows better forecasting of the actual response expected from dispatched DSPs, which allows more secure operation of the power system.

Under both static and dynamic baselines, each DSP has a specified minimum load below which it cannot be dispatched. Dispatch is also restricted to the number of Capacity Credits.

Some RCMRWG participants raised concerns about potential for gaming of a dynamic baseline. For example, if the baseline were set by interpolating between consumption immediately before and after the dispatch period, a DSP could artificially increase its consumption in those periods to increase its baseline.

EPWA has not yet considered any specific forms of dynamic baseline, but considers that a robust dynamic baseline could be set based on consumption on a range of previous similar days, rather than using periods after a participant knew the DSP would be dispatched.

The MAC generally supported a move to dynamic baselines for DSP dispatch. The MAC discussed potential for DSP proponents to nominate either a static or dynamic baseline but agreed that the additional complexity was unwarranted. One member considered that a static baseline was preferable because it meant that a load was dispatched against the same value on which its IRCR was calculated.

RCMRWG discussions on DSP dispatch arrangements raised the minimum availability of 200 hours per year as a barrier to participation for some loads which could curtail but are concerned about the impact on their operations.

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.

Consultation Questions:

(11) Do stakeholders agree that measurement against a dynamic baseline would better reflect the actual contribution of DSPs at times of system stress?

(12) Would reducing the 200 hours that DSPs can be dispatched for in a year meet better the WEM objectives and, if so, what would be a more appropriate number of hours?

5. Other Aspects of the RCM

The scope of the RCM Review includes identifying changes needed to supporting processes to accommodate design changes in the RCM as a whole.

Changes to the outages, testing, and refund regimes are needed to incorporate the new flexible capacity product, to accommodate changes to DSP arrangements and to amend the distribution of capacity rebates. No changes are required outside these areas.

5.1 Testing

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

5.1.1 Current Approach

The current capacity testing regime tests the ability of a Facility to reach its maximum certified output level twice per year – once between October and March, and again between April and September. A Facility can pass during a scheduled test, or by observation, if it happens to achieve its required level in the normal course of market operations. A Facility gets two chances to pass a scheduled test – if it fails both, its Capacity Credits are reduced to the maximum level achieved.

DSPs are treated slightly differently:

- A DSP must undergo an annual Reserve Capacity test (clause 4.25.1(c)) between October and March to show that it can deliver a level of reduction from its static baseline equal to its assigned Capacity Credits for two Trading Intervals.
  - A DSP gets two chances to pass this test – on failing twice, the DSPs Capacity Credits are reduced to the level of reduction achieved, and it must refund any capacity payments relating to the non-performing capacity;
- A DSP must undergo an annual verification test (clause 4.25A) in October/November to show that it can deliver a level of reduction from its static baseline of at least 10% of its assigned Capacity Credits for at least one Trading Interval.
  - 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 it is failed twice.

5.1.2 Required Changes

Flexible Capacity

Current capacity testing focuses on the ability to deliver energy. 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 an unsynchronised 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.

When scheduling tests, the capabilities should ideally be tested at a point in the year before they are likely to be needed, but not so far before that system conditions are considerably different. Because the maximum ramp for the year is likely to occur in shoulder seasons, the ideal timing would be towards the ends of the summer and winter seasons.

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.

Consultation Questions:

(13) Do stakeholders see any other aspects of flexible capacity that should be included in the testing regime?

(14) Do stakeholders agree that flexible characteristics can be tested by observation?

(15) Should flexible capacity tests be scheduled at the same time as peak capacity tests?

Testing DSPs

DSPs are currently tested against a static baseline. 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.

The second test for DSPs requires only that it decrease output by 10% of its Capacity Credits. This is different from the treatment of other Facilities that must fully demonstrate their capability twice each year.

DSPs that fail two tests currently have no incentive to restore their capability to meet their original level of Capacity Credits for rest of the capacity year. Instead of treating a test failure 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. Participants could still choose to voluntarily surrender Capacity Credits if they expected to be unable to remedy the situation.

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.

Consultation Questions:

(16) Do stakeholders agree with the changes to reserve capacity testing for DSPs?

(17) What are stakeholder views on completely aligning the generation and DSP testing regimes?

5.2 Outage Planning

5.2.1 Current Approach

Generation facilities holding Capacity Credits are required to participate in the outage planning process. These Facilities must request and receive permission for planned outages, and must notify AEMO when a forced outage occurs. This ensures that Facilities will not be on planned outage during times of likely system stress, and that Facilities who are unavailable can be required to pay back some of the money they have been paid on the basis that their capacity will be available.

DSPs do not participate in the outage planning process. Instead DSPs:

- can lodge CDAs to be considered in the CRC process; and
- are judged to be insufficiently available (and pay refunds) when the Relevant Demand (static baseline) of their Associated Loads less the minimum demand of their Associated Loads is less than the quantity of Capacity Credits held.

5.2.2 Required Changes

Outage Planning for Flexible Capacity

When capacity is on outage (whether planned or unplanned) for peak capacity, it will necessarily be on outage for flexible capacity as well. It is not possible for a Facility to provide flexible capacity while its peak capacity capability is on outage.

Given that the RCR for peak and flexible capacity will be different, it is likely that, at times, there will be:

- sufficient peak capacity available so that some facilities can go on planned outage while leaving enough capacity to meet the expected peak demand; while simultaneously
- insufficient flexible capacity available to ensure that the expected ramping needs can be met if flexible 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.

Proposal M: Amend the outage planning process so that AEMO considers availability of both peak and flexible capacity when assessing and approving outages. **Consultation Questions:** (18) Do stakeholders agree with the proposed changes to AEMO's outage assessment process?

Outages for Flexible Capacity

The key difference between peak and flexible capacity is the speed with which it can be delivered and the lack of constraints on delivery. With this in mind, the outage regime will need to account for situations where a facility can still provide peak capacity but cannot provide flexible capacity, as follows:

- Participants will need to report technical parameter restrictions affecting facilities holding flexible Capacity Credits, including ramp rate, minimum stable generation, and minimum start/run/stop times;
- if a facility's parameters become such that it would no longer meet the requirements to be certified as flexible, it would be designated as being on outage for the purposes of flexible capacity. Such an outage could be planned or forced; and
- if AEMO observes non-response to dispatch such that a Facilities operational parameters do not meet the requirements to be certified as a flexible capacity provider, then the facility would be required to lodge a forced outage for the flexible capacity service.

Proposal N: Require flexible capacity holders to lodge outages relating to capability to provide flexible capacity. **Consultation Questions:** (19) Do stakeholders agree with the proposed approach to flexible capacity outages?

DSPs Outage Planning

DSPs do not currently participate in the outage planning process. As noted in section 4.2.4, EPWA is planning to remove the ability of participants to lodge CDAs, whereby DSP owners manage their own outages without reference to AEMO.

Although DSP owners will no longer have the ability to lodge CDAs, the proposed method for setting DSP CRC (see section 4.2.3) allows for past availability to be considered, meaning DSP owners will still be incentivised against taking outages at times of likely system stress, and can continue to manage their own outages.

However, the move to a dynamic dispatch baseline means that measuring facility availability against its Relevant Demand will no longer be appropriate. Facility availability for curtailment needs to be measured as the actual demand of Associated Loads less their minimum demand during periods of required availability. This ensures that DSPs are incentivised both to be available for curtailment during system stress periods, and (assuming DSP the availability period remains 8am to 8pm on weekdays) not to contribute to minimum load problems during the middle of the day.

Alternatively, DSPs could be required to lodge planned outage requests in the same way as energy producing facilities. Under this approach, DSP outages would be subject to approval by AEMO, and DSPs would not be subject to capacity refunds for being unavailable during these times.

EPWA considers that the infrequent nature of DSP dispatch and the availability incentives provided by the certification and refund processes means 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.

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.

Consultation Questions:

(20) Do stakeholders agree with the proposed approach to DSP outages?

5.3 Refunds

5.3.1 Current Approach

The current peak capacity refund regime assesses capacity payment refunds for a Facility on unplanned outage, or with a planned outage rate greater than a defined threshold.

Refunds are assessed at a higher rate in periods where most capacity is already generating, and at a lower rate when there is plenty of spare capacity. The rate is capped at 6 when there is less than 750 MW of spare capacity.

A DSP pays capacity refunds if:

- it fails the availability requirement discussed in section 5.2.1; and
- when dispatched, it fails to deliver the requested demand reduction.

If a DSP fails all tests in a Capacity Year and does not demonstrate an ability to curtail by at least 90% of its Capacity Credits, it forfeits its DSM reserve capacity security (25% of expected annual capacity payments).

Collected refunds are distributed to capacity providers who met their availability obligations in the affected intervals.

5.3.2 Required Changes

Flexible Capacity

Capacity refunds are a critical part of the RCM, providing the main incentive for facilities to meet their availability obligations. Capacity refunds therefore need to be in place for flexible capacity to ensure that participants meet obligations to make capacity available.

Because participants will be paid only a single price for their capacity,[22] there is no separation between capacity payments relating to flexible capacity and those relating provide peak capacity. When there is a price premium for flexible capacity, it would be possible to calculate two separate payment amounts for each facility:

- one for peak capacity, roughly consisting of the peak capacity price multiplied by the peak capacity credits held; and
- one for flexible capacity, consisting of the difference between the total capacity payments received and the peak capacity amount.

If refunds were assessed from these separate payment amounts, the incentive to meet flexible capacity obligations would be weaker than the incentive to meet peak capacity obligation in all situations where the flexible price was less than twice the peak capacity price. In situations where there is no price premium for flexible capacity (likely indicating that peak capacity is in relatively shorter supply than flexible capacity), there would be no price premium, and no separate payment pool.

EPWA considers that this skewed incentive is not appropriate, and that refunds for both products should come from a single payment pool.

RCMRWG members raised concerns that, if there is no price premium for facilities providing the flexibility service, and facilities have to pay capacity refunds for both peak and flexible capacity from the same pool of capacity payments, then where they are unavailable for flexible service, they will pay more in refunds than they would have if they had not registered for flexible capacity in the first place. Some participants may choose not to be certified for flexible capacity under such an arrangement.

EPWA considers that this situation is unlikely, as:

- capacity nominations occur in advance of capacity price determination, meaning that participants must decide whether to certify for flexible capacity before knowing whether there will be a price premium;
- there will likely be a price premium in the short to medium term (see Chapter 5.4);
- situations in which facilities are able to meet peak capacity obligations but not flexible capacity obligations are likely to be a minority of outages; and
- if a participant considers that it faces a significant risk of lengthy periods on outage for flexible capacity but not peak capacity, then accrediting for peak capacity only is a reasonable outcome.

22 Though facilities providing both peak and flexible capacity can receive a higher price than facilities providing peak capacity only.

However, it would be possible to cap participant exposure to flex-only refunds at some portion of capacity payments to ensure that facilities suffering long term inability to provide flexible capacity still retain some incentive to provide peak capacity.

Proposal P:

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

Consultation Questions:

(21) Do stakeholders agree with the proposed approach to flexible capacity refunds?

(22) If stakeholders consider that the potential refunds for flex-only outages should be capped, what proportion of the total payments would they suggest, and why?

The dynamic refund multiplier for peak capacity refunds is an important part of signalling the increased importance of availability at times of system stress. A dynamic refund multiplier can be made specific to the availability of flexible capacity by basing the multiplier on either:

- the remaining available undispatched flexible capacity; or
- the ratio between the actual ramp in the interval and the ramp assumed when setting the flexible capacity RCR.

Using the undispatched flexible capacity would mean a low multiplier at the beginning of the ramp, and a higher multiplier at the end of the ramp. This signal does not properly reflect the periods of system stress, it would also mean the multiplier is still based on peak load, which is not aligned to the periods of highest ramp, which fall outside the hot season.

Using a ramp ratio would mean the multiplier is consistently highest during periods of highest ramp (with similar profile to that seen in Figure 8), but more volatile. Volatility could be reduced by calculating the actual ramp over multiple prior intervals rather than a single interval.

During an outage that affects both peak and flexible capacity, the appropriate multiplier would be the greater of the two dynamic multipliers.

Predictability could be supported by having AEMO publish ramp rate statistics alongside load forecast.

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.

Consultation Questions:

(23) Do stakeholders agree with the proposed approach to refund multipliers?

DSPs

A DSP that does not perform currently loses its reserve capacity security only if it never demonstrates that it can reduce demand by 90% of its Capacity Credit allocation in at least two trading intervals. As long as it does this at least once, its capacity refunds are capped at its total capacity payments.

Unlike for generation facilities, participants are unlikely to have invested in significant capital expenditure to set up a DSP. This means that the consequences of losing capacity payments are unlikely to be as severe.

To ensure that DSP owners retain an incentive to be available after they have passed their tests, EPWA proposes to include the DSM Reserve Capacity Security in the maximum refund amount for DSPs.

Proposal R:

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

Consultation Questions:

(24) Do stakeholders agree with the proposed approach to DSP refunds?

Capacity Rebates

Currently, collected capacity refunds are distributed to other capacity providers who met their obligations. The effect of this rule is that consumers still pay for the un-provided service when a capacity provider fails to provide capacity, but the funds are redistributed to increase the capacity payments made to some providers. Where AEMO contracts Supplementary Reserve Capacity to replace the missing capacity, consumers will pay again.

EPWA considers that it is more equitable to distribute collected capacity refunds to consuming participants rather than capacity providers.

Alternatively, collected refunds could be put towards the cost of Supplementary Capacity and/or NCESS, with only the surplus distributed to consumers. This would achieve the same effect as rebating payments to customers, but would require more complex intermediate settlement arrangements.

Proposal S:

Distribute collected capacity refunds to consuming participants rather than other capacity providers.

Consultation Questions:

(25) Do stakeholders agree with the proposed distribution of collected capacity refunds?

5.4 The EUE Target in the Planning Criterion

Given the uncertainty about the future reference technology, and therefore the BRCP, the Stage 1 Paper considered that there was no strong economic justification for changing the EUE target. Based on the analysis presented, submissions supported retaining the target EUE percentage at 0.002%.

At the same time, continuing developments in the WEM and National Energy Market (NEM) reflect Government's low tolerance for risks to system reliability. The AEMC recently issued its draft decision to extend the NEM interim reliability measure[23] of 0.0006% EUE until 2028.

In the WEM, which is a smaller market without interconnections, the recent procurement for 830 MW of NCESS service illustrates the government's low appetite for risk.

Further analysis indicates that the peak demand limb of the Planning Criterion will continue to dominate a 0.002% EUE target for some years. The analysis compared the amount of additional capacity required to meet the peak demand limb of the Planning Criterion with the amount of additional capacity required to keep EUE to 0.0015%, 0.001%, 0.0005%, 0.0003% and 0.0002% targets. Preliminary analysis clearly showed that higher EUE targets required much less capacity than the peak demand limb of the Planning Criterion so in depth analysis was performed using 0.0003% and 0.0002% targets only.

Two different mixtures of additional capacity tested in the modelling is summarised in Table 8. New generic capacity was assigned Capacity Credits using a factor of the generator type's nameplate capacity. This was calculated using ESOO 2022 capacity credit allocations.

Table 8: Additional Generic Capacity Type, and Capacity Credit Nameplate Multiplier

Additional Capacity Type	Generic Intermittent Capacity-Mix Splits		Capacity Credit Nameplate Multiplier
	Mix 1	Mix 2	
Solar	37.5%	15.0%	0.244
Wind	37.5%	60.0%	0.251
Battery	20.0%	20.0%	1
DSP	5.0%	5.0%	1

In all scenarios, COLLIE_G1 retires in 2027. Current capacity was sufficient to meet EUE targets in a scenario using the 2022 ESOO's 10% POE peak demand and Base annual demand growth. Therefore, a stress test scenario was modelled using 10% POE Peak, and high annual demand growth values.

23 https://www.aemc.gov.au/market-reviews-advice/review-interim-reliability-measure

Figure 14: Peak and Annual Operational Demand

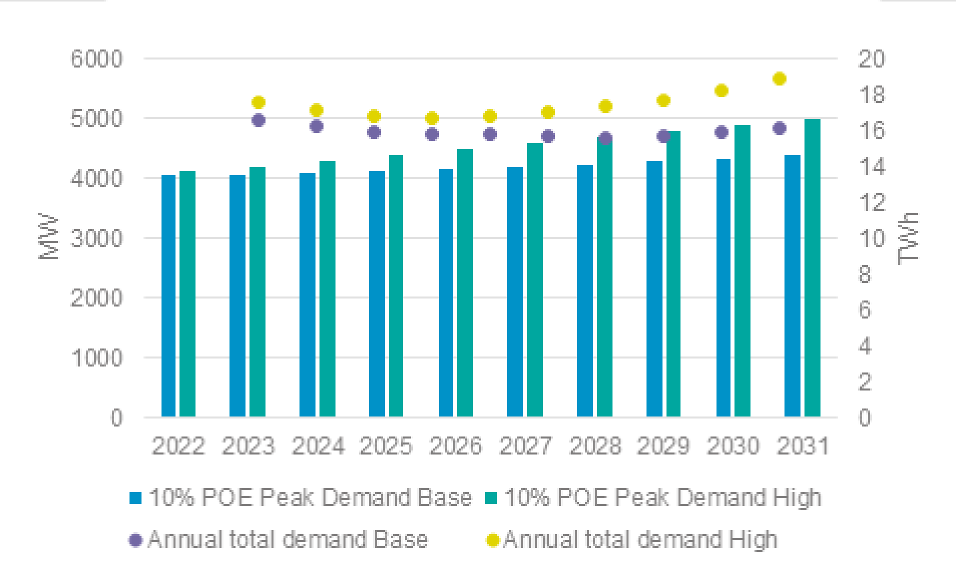
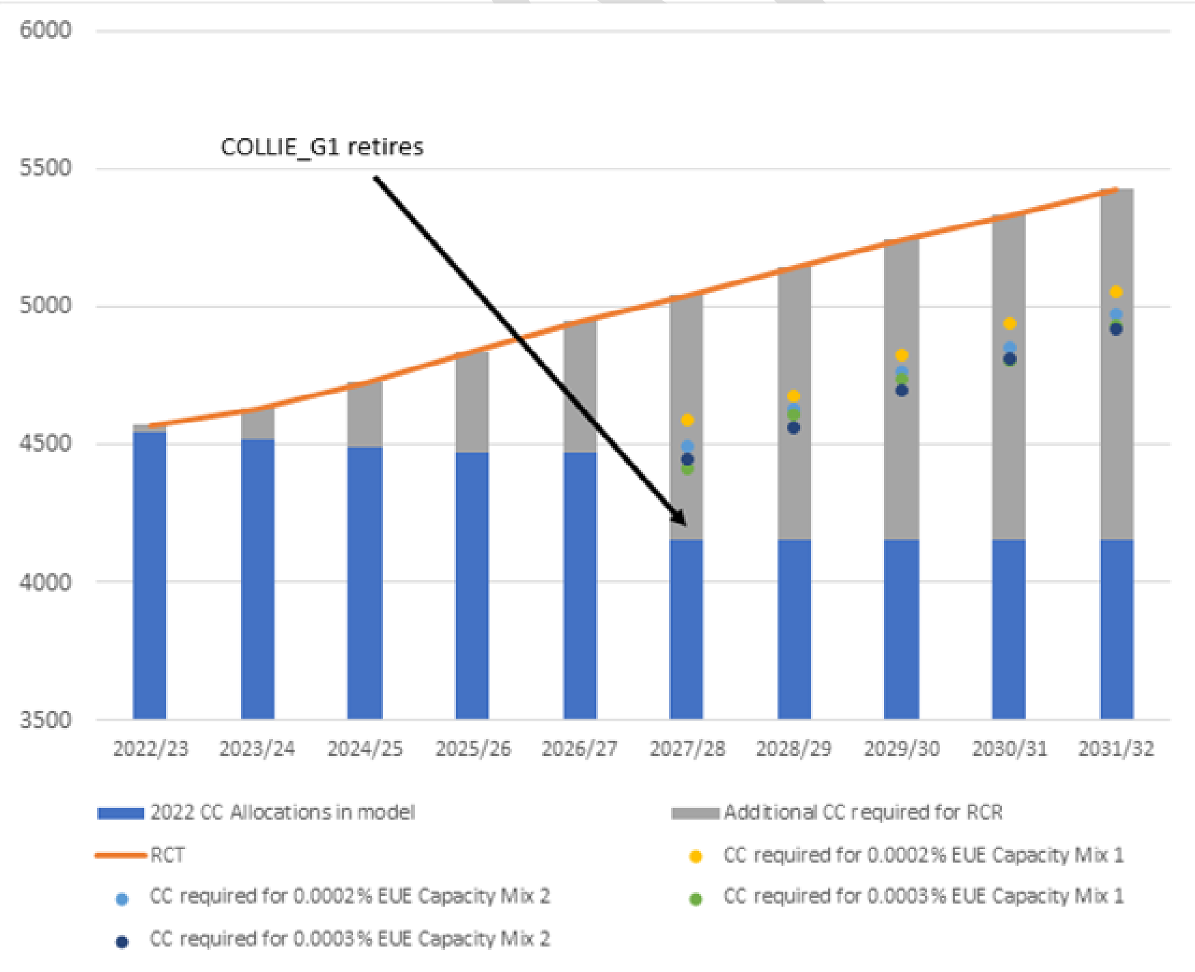


Figure 14 shows that the additional capacity required to meet the peak demand component of the planning criterion exceeds the additional capacity required to satisfy 0.0002% and 0.0003% EUE targets in the high annual demand 10% POE scenario when using both additional capacity mixes, and is likely to do so through to the 2040s.

Figure 15: High demand growth 10%POE peak demand EUE and RCT



An EUE target of 0.0002% would bring the EUE limb closer to the peak demand limb, and better reflect the reduced appetite for risk of supply interruptions.

Proposal T:

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

Consultation Questions:

(26) Do stakeholders agree with the proposed change to a 0.0002% EUE target in the Planning Criterion?

5.5 Determination of the BRCP

Submissions supported having separate capacity prices, with different underlying technologies for each of the peak and flex capacity produces, However, the submissions were concerned that the methodology should consider all elements influencing the price, and in particular the expected commercial life of the asset rather than it’s theoretical design life and the expected energy storage duration required in the market, which may require more energy than capacity. Respondents also considered that any significant change to the underlying reference technology should be signalled well in advance.

EPWA agrees that the reference technology for the peak and the flexible capacity products may be quite different, to the point of having a different underlying facility types.

EPWA considers that the underlying technology used in the BRCP methodology would be better reviewed and determined by the Coordinator, with the ERA focusing on the other parameters. The potential move to a net CONE approach is driven by the technology selected, and should be included in the Coordinator’s review.

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.

Consultation Questions:

(27) Do stakeholders agree that the Coordinator should determine the reference technology for each of the capacity products?

(28) Do stakeholders agree that the potential adoption of a net CONE approach should be considered with the reference technology?

6. Financial Analysis

[To be included for publication.]

PART THREE – APPENDICES

Appendix A. Responses to the Stage 1 Consultation Paper

[To be included for publication.]

Appendix B. CRC Allocation for Facilities in Capability Class 3

[To be included for publication.]

Appendix C. IRCR Interval Selection for Historic Years

[To be included for publication.]

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

Agenda Item 9 Update on the SRC Review

Market Advisory Committee (MAC) Meeting 2023_04_20

1. Purpose

- For Energy Policy WA (EPWA) to provide the MAC with an update on 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 consultation as presented in the table, and
- the recommendations from the Coordinator to the Minster to improve the SRC procurement process.

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 initiate a review of the SRC in two stages:
    - Stage 1 assesses the effectiveness of the SRC procurement process.
    - Stage 2 assesses the performance of the procured SRC services.
- EPWA has engaged ACIL Allen to assist with this review.
- Stage 1 of the Review has been completed after comprehensive stakeholder engagement that discussed possible improvements to the SRC Provisions. The stakeholder engagement included:
    - close individual consultation with AEMO and Western Power throughout the whole process;
    - a stakeholder questionnaire sent to organisations identified to have an interest in the SRC process on which EPWA received eight responses, some of them through interviews;

- a consultation paper with proposed improvements to the SRC procurement process including proposed Amending Rules on which EPWA received eight submissions[1]; and
- a meeting of the Transformation Design and Operation Working Group (TDOWG) that was held on 15 March, 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**.

Recommendation from the Coordinator to the Minister on 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:
  - introduce a non-binding EOI process for the provision of supplementary capacity;
  - not limit participation in a tender process to respondents shortlisted in the EOI process;
  - provide for a formal role for Western Power to assess any network access matters relating to the responses to the EOI and SRC procurement process; and
  - introduce a requirement for AEMO to inform respondents to the call for EOI whether their proposed services are likely to meet the requirements in the EOI.
- The proposed WEM Amendment (Supplementary Reserve Capacity) Rules 2023, have been submitted to the Minister.
- EPWA expect that the Amending Rules will be gazetted late April, after the Minister's power to make amending WEM rules are reinstated.

3.3. Next Steps

- EPWA commenced stage 2 of the SRC Review on 1 April 2023 and is currently developing a stakeholder questionnaire.

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

4. Attachments

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

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).

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

Summary of Feedback in Submissions on the Consultation Paper and EPWA's Responses

<table>
<tr><th>Proposed Change</th><th>Clause</th><th>Submitter</th><th>Submitter Feedback/Suggestions</th><th>Response to Feedback</th></tr>
<tr><td colspan="5">Proposed improvements to the process timeline</td></tr>
<tr><td rowspan="7">PROPOSAL 1 (a)

EPWA proposes to provide AEMO with the discretion to run a non-binding Expressions of Interest (EOI) process for SRC at any time from 1 April in any year, if it becomes aware of a potential risk that, if eventuating, could require an SRC procurement process.</td><td rowspan="7">4.24.1A (new)</td><td>Perth Energy</td><td>Supportive</td><td></td></tr>
<tr><td>Western Power</td><td>Supportive</td><td>.</td></tr>
<tr><td>AEMO</td><td>Supportive</td><td></td></tr>
<tr><td>Synergy</td><td>No comment</td><td></td></tr>
<tr><td>Enel X</td><td>Supportive, however Enel X notes an EOI cannot be a substitute for concluding contracting a reasonable time ahead of the Hot Season.</td><td>EPWA notes that the proposed change does not change the requirement for a subsequent SRC procurement processes.</td></tr>
<tr><td>Collgar</td><td>Supportive</td><td></td></tr>
<tr><td>Shell Energy</td><td>Shell Energy do not support that tan EOI process for SRC is undertaken every year and considers it should be limited to years when it is determined that there is a high probability of requiring SRC.

Shell Energy encourages EPWA and AEMO to consider alternative options to improve the SRC procurement process.</td><td>EPWA notes that the proposal provides that AEMO should only call for EOI if it considers it is likely that SRC will need to be procured later.</td></tr>
</table>

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
	4.24.1B (new)	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Synergy notes that there is no timeframe provided within the WEM rules for the submission period for the expression of interest period. Synergy suggests that the length of the submission window should be consistent with that for the call for tenders (in clause 4.24.6). Synergy notes that some product service offerings may require a longer timeframe than others and considers that AEMO should allow for the maximum time (30 Business Days) where appropriate. Synergy provided drafting suggestions (see Synergy's submission for details).	EPWA considers that the time allowed to respond to a call for EOI will depend on when a potential risk is identified by AEMO and should be set at AEMO's discretion. EPWA also notes that the final decision is to not implement the shortlisting of services in the proposed EOI process and to not limit participation in an SRC tender process to services offered in the EOI process. Therefore, it is not necessary to specify the time allowed to respond to a call for EOI in the WEM Rules.
		Enel X	Supportive	
		Collgar	Supportive	
		Shell	No comment	
PROPOSAL 1 (b) EPWA proposes to require AEMO to assess all responses to the EOI	4.24.1C (new)	Perth Energy	Supportive	
		Western Power	Western Power are supportive of a shortlist approach, and being involved in the shortlist	The final decision is that the shortlisting provisions will not be implemented.

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
call and prepare a shortlist that includes all potential services that AEMO considers will likely meet the SRC requirements if an SRC tender is subsequently initiated by AEMO.			process to influence outcomes when Western Power is a key stakeholder. We suggest this (Western Power's involvement) is incorporated as an additional bullet point in 4.24.1C	However, further amendments have been made to clause 4.24.1C to provide a formal role for Western Power in the assessment of responses to a call for EOI.
		AEMO	Supportive	
		Synergy	Synergy does not support the proposal of limiting the tenders to the EOI shortlist. A suggested alternative approach may be for Western Power and the Australian Energy Market Operator (AEMO) to work together to determine which tender offers they do not expect to be reasonably able to be delivered on time and remove these offers from the tender process. Synergy provided drafting suggestions (see Synergy's submission for details).	The final decision is to not implement the shortlisting of services in the EOI process and to not limit participation in a subsequent SRC tender process to services offered in the EOI process.
		Enel X	Supportive	
		Collgar	In order to avoid wasting valuable resources on preparing proposals that have a low chance of approval, it is proposed that AEMO provide preliminary feedback on the likelihood of a project being approved. This feedback can help guide project proponents in refining their proposals or identifying alternative solutions, ultimately leading to a more efficient and effective process for all involved.	Further amendments have been made to clause 4.24.1C to require AEMO to provide feedback on all responses to a call for EOI.
		Shell	Shell Energy do not support a shortlist via an EOI process for SRC to be undertaken every	See above.

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
			year as we believe this should be required only if it is determined that there is a high probability of requiring SRC in the forward year.	
PROPOSAL 1 (c) EPWA proposes to require that only potential services from the shortlist are allowed to participate in a subsequent tender process, if one is subsequently initiate by AEMO.	4.24.8(aA) (new)	Perth Energy	For this reason, Perth Energy suggests that AEMO should have the right to call tenders only from the EOI shortlist but not be obligated to do so. Perth Energy provided alternative drafting.	See above
		Western Power	Supportive	
		AEMO	Supportive	
		Synergy	Synergy does not support the proposal of limiting the tenders to the EOI shortlist. A suggested alternative approach may be for Western Power and the Australian Energy Market Operator (AEMO) to work together to determine which tender offers they do not expect to be reasonably able to be delivered on time and remove these offers from the tender process.	See above
		Enel X	Supportive	
		Collgar	Supportive	
		Shell	No comment	
Proposed improvements to the contracts for SRC Services				
PROPOSAL 2	4.24.14	Perth Energy	Supportive	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
EPWA proposes to amend the WEM Rules to: • require AEMO to develop and publish a non-negotiable Standard Form of Contract, that contains the general terms and conditions of the contracts; and • allow for the negotiation of specific terms and conditions for limited aspects of the Standard Form Contract, including prices, of individual contracts.		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Synergy agrees that the intent of attempting to limit the list of potential contract variations may result in a more timely process for AEMO, however cautions that a "one size fits all" approach to the Standard Form Contract may not be appropriate for the various potential services that could be offered in the SRC. Synergy notes that the current Standard Form Contract does not seem to consider Distributed Energy Resources and unmetered assets and how these types of services may differ to offer potential service provides. These types of assets could provide valuable services to the industry, however the current arrangements make it difficult for these types of facilities to participate. Potentially, the Standard Form Contract could consider the range of different product offerings and include, for selected contract clauses, several options to suit each different product offering that the tender parties can choose between. Further, AEMO should workshop the initial Standard Form Contract with industry to discover any potential issues with the proposed drafting and resolve these in a timely manner. Synergy provided alternative drafting (see Synergy's submission for details)	Clause 4.24.14 is further amended to require that AEMO consults with stakeholders when developing the Standard Form Contract.
		Enel X	Support an improved SRC contract structure with clear demarcation between negotiable and non-negotiable elements. Enel X would be willing to	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
			engage in the wider industry review of the new SRC contract structure.	
		Collgar	Supportive	
		Shell	No comment	
PROPOSAL 3 EPWA proposes that the maximum duration of contracts for SRC be extended to the current definition of the Hot Season, as defined in Chapter 11 of the WEM Rules), i.e. ~16 weeks.	4.24.13	Perth Energy	Extending the contracting period to cover the whole of the Hot Season, as recommended in Proposal 3, addresses the perceived problem of a misalignment between the contracting term and the hot season. Again, noting the extensive closures scheduled for the coming years, the remaining providers may not be able to individually meet the full commitment of the Hot Season. If this period is too long for some providers, which would exclude them from offering the provision of service, consideration could be given to accepting proposals for entities that can only offer supplementary capacity for a shorter period, as these partial offers may be grouped to meet the proposed period and / or if insufficient "full term" capacity is offered.	Clause 4.24.13 has been further amended to remove any perception that contract terms will always have to cover the entire Hot Season.
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
		Enel X	Supportive	
		Collgar	Supportive	
		Shell	Supportive	
Proposed improvements to specifying Western Power's role in the SRC process				
PROPOSAL 4 EPWA proposes to amend the WEM Rules to provide for a formal role of Western Power to support the SRC procurement process.	4.24.18A (new)	Perth Energy	Supportive	
		Western Power	It would be helpful for the WEM Procedure to identify the requirements on Western Power on the information and assistance participants requires [sic] from Western Power, including timeframes.	Clause 4.24.18A has been further amended to address Western Power's concern.
		AEMO	Supportive	
		Synergy	Synergy notes that the information sharing of the expression of interest and the SRC tenders should be limited to technical information that is needed to assess the deliverability and capability of the product services being offered.	EPWA considers that it is important that Western Power and AEMO cooperate fully to ensure any supplementary capacity is provided at the lowest possible cost and on the most efficient basis.
		Enel X	No comment	
		Collgar	To increase efficiency and reduce the burden on project proponents, it is recommended that a process be established to exempt certain projects from full Western Power modelling requirements when only minor changes are	It is beyond scope of the SRC Provisions to address Western Power's network connection processes more generally.

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
			made to a facility. This exemption would apply to projects that do not significantly impact the overall facility performance or the interconnected power system. By implementing this exemption process, resources can be allocated more effectively, and project development timelines can be reduced. To expedite the proposal process for SRC projects, it is suggested that the Application and Queuing Policy be relaxed specifically for these types of proposals. This relaxation could include measures such as reduced waiting periods, streamlined application requirements, or prioritization of SRC proposals in the queue. This policy adjustment would help accelerate the development and implementation of critical SRC projects, ensuring a more resilient power system.	
		Shell	No comment	
Proposed improvements to the SRC WEM Procedure				
PROPOSAL 5 (a) EPWA proposes to add the following to the relevant WEM Procedure making heads of power that the WEM Procedure documented under clause 4.24.18 must also provide:	4.24.18	Perth Energy	Supportive	
		Western Power	Name is not a required field in the information made available to respondents as it will often be an email inbox as the primary contact.	Clause 4.24.18 has been further amended to address Western Power’s concern.
		AEMO	Supportive	
		Synergy	Supportive	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
(a) requirements regarding the information and assistance AEMO requires from Western Power; (b) requirements, developed in consultation with Western Power, on the information that must be provided by those applying to provide Eligible Services, who request assessment of related aspects of their application from Western Power; (c) timelines for the provision of requested information and for the assessment of requests that relate to the provision of SRC; and (d) the name and contact details, provided by Western Power, which must be used when assistance or assessment by Western Power is requested.		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
	4.24.18A (new)	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
PROPOSAL 5 (b) EPWA proposes to add the following to the relevant WEM	4.24.18B (new)	Perth Energy	Supportive	
		Western Power	No comment	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
Procedure making heads of power that a request for assistance or assessment to Western Power by those applying to provide Eligible Services or AEMO must: (a) be in writing and addressed to the person nominated by Western Power in the WEM Procedure; (b) allow sufficient time to enable Western Power to make the requested assessment in accordance with the timelines set out in the Procedure; and (c)contain sufficient information and analysis as prescribed under the WEM Procedure.		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
		Alinta	No comment	
	4.24.18C (new)	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
Proposed improvements to the proponent redness and submissions quality				
PROPOSAL 6		Perth Energy	No comment	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
EPWA is considering whether to amend the WEM Rules to introduce additional qualitative assessment criteria to ensure that tender submissions are of sufficient quality and maturity. In particular, whether the WEM Rules should specify: • the level of certainty regarding access to the network required for an Eligible Service; and • the level of compliance with the Technical Rules required for an Eligible Service.	n/a	Western Power	Western Power supports the introduction of network access certainty, level of compliance to Technical Rules, and meeting Minimum Generation Performance Standards, as criteria for the tender assessment. Western Power welcomes being part of the process to either define the criteria or have direct input into the process to influence outcomes where Western Power is a key stakeholder.	Following consideration of the stakeholder responses, the Coordinator has decided that a rule change is not required at this time. However, the Coordinator acknowledges the mixed stakeholder views on this issue, will further assess this matter, and the need for changes to the WEM Rules, during Stage 2 of the SRC Review.
		AEMO	Supportive	
		Synergy	Synergy supports the introduction of provisions into the Wholesale Electricity Market (WEM) Rules or the WEM Procedure that allows for AEMO and Western Power to remove tenders that both parties do not consider will be reasonably capable of being able to deliver the service on time.	See above
		Enel X	Supportive	
		Collgar	Collgar understand the importance of ensuring that proposals submitted for assessment possess an adequate level of detail and quality. However, increasing the rigidity of the WEM Rules might not guarantee improved market outcomes. Instead, it may be more suitable for AEMO to undertake a thorough quality review when evaluating EOI proposals. Since network access might not be established before a proposal is	See above

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
			submitted, the rules should offer flexibility in considering the project's likelihood of initiation. Collgar supports the possibility of relaxing compliance levels with technical rules, where feasible.	
		Shell	No comment	
PROPOSAL 7 EPWA proposes to amend the WEM Rules to require that the length of the notice period for activation of Eligible Services is, to the extent practicable, aligned with the length of the notice period for activation for equivalent type of services under the WEM Rules (e.g. Demand Side Programmes).	4.24.13	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	AEMO considers that the use of the phrase 'equivalent services under the WEM Rules' creates uncertainty and may be difficult to apply in practice, as it may not be clear which services under the WEM Rules are deemed to be equivalent to each of the types of Eligible Services in clause 4.24.3. Further, reducing the notification time for load reduction SRC measures to align with Demand Side Programme notification (assuming they are deemed to be equivalent) may reduce SRC deployment by ruling out potential SRC providers that are unable to implement load reduction measures with a 2-hour notification time. AEMO acknowledges Energy Policy WA's concerns that a 9-hour notification period may result in sub-optimal outcomes with regards to procurement and deployment of SRC. AEMO's preference is to remove reference to 'equivalent types of services' and work with Energy Policy WA on determining an appropriate	Clause 4.24.13 has been further amended to address AEMO's concern.

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
			notification time for SRC Eligible Services that balances these issues, with input from industry.	
		Synergy	Synergy considers alignment of the notification period for SRC activation with that applicable to Demand Side Programmes (DSPs), being 2 hours, may exclude numerous potential services from the SRC process. Synergy notes that a 2-hour notification period is unlikely to be sufficient: • to allow Electric Storage Resources (ESR) facilities to ensure they are fully charged for the activation period; • for load shifting to be undertaken to ensure that load is not going to be consumed in the activation period (for example pool pumps, heat pumps etc may need to run earlier in the day); • to enable the full potential of an aggregation of Distributed Energy Resources (DER) and flexible loads to be realised due to the time needed to orchestrate the maximum volume of the service product; and • to allow for generators to secure short term fuel supply to the full dispatch requirement of the SRC volume contracted. Synergy notes that the notification period needs to be reflective of the type of service product being offered and the differing requirements for the different facility types. Synergy suggests a workshop with industry to determine what notification periods are best suited for different facility types.	Clause 4.24.13 has been further amended to address Synergy's concern.

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
		Synergy	Supportive	
		Enel X	Supportive	
		Collgar	No comment	
		Shell	No comment	
Other proposed Changes – Minor amendments				
PROPOSAL 8 EPWA also proposes to replace "generation" with "production" of electricity throughout section 4.24 of the WEM Rules to ensure Electric Storage Resources are not prevented from offering "Eligible Services".	4.24.3	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Synergy agrees that the drafting of the WEM Rules should be revised to ensure that ESR and DER facilities are not inadvertently excluded from participation due to the drafting stating "generation". Synergy however seeks clarity as to whether the proposed alternative drafting of "electricity production" allows for the inclusion of ESR and DER facilities that are sitting idle (i.e. they are providing a service by not consuming or withdrawing energy)?	EPWA considers that the Amending Rules, as currently drafted, will allow ESR and DER facilities to provide a SRC services. See section 3.8 of this Information Paper.
		Enel X	No comment	
		Collgar	Supportive	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
		Shell	No comment	
PROPOSAL 9 EPWA also proposes a number of other changes to improve clarity and consistency, and avoid ambiguity in the current provisions in section 4.24, including changes to the definition of Eligible Services in clause 2.24.3.	4.24.1	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
	4.24.3(a)	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
	4.24.3(b)	Perth Energy	Supportive	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
	4.24.3(c)	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
	4.24.11	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
	4.24.11A (new)	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	
		Collgar	Supportive	
		Shell	No comment	
	4.24.19	Perth Energy	Supportive	
		Western Power	No comment	
		AEMO	Supportive	
		Synergy	Supportive	
		Enel X	No comment	

Proposed Change	Clause	Submitter	Submitter Feedback/Suggestions	Response to Feedback
		Collgar	Supportive	
		Shell	No comment	