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

Meeting Agenda

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	Tuesday 23 August 2022
Time:	9:30 AM – 11:30 AM
Location:	Online, via TEAMS.

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda	Chair	Noting	2 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	Minutes of Meeting 2021_06_28	Chair	Decision	2 min
4	Action Items	Chair	Noting	2 min
5	Market Development Forward Work Program	Chair/Secretariat	Discussion	2 min
6	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Noting	2 min
	(b) Reserve Capacity Mechanism (**RCM**) Review Working Group	Working Group Chair	Noting	5 min
	(c) Cost Allocation Review (**CAR**) Working Group	Working Group Chair	Noting	5 min
7	Rule Changes			
	(a) Overview of Rule Change Proposals	Chair/Secretariat	Noting	2 min
8	RCM Review draft Consultation Paper	Chair/Secretariat	Discussion	90 min
9	General Business	Chair	Discussion	2 min
	Next meeting: Tuesday 11 October 2022			

Please note, this meeting will be recorded.

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

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	28 June 2022
Time:	9:30am –11:35am
Location:	Videoconference (Microsoft Teams)

Attendees	Class	Comment[1]
Sally McMahon	Chair	
Dean Sharafi	Australian Energy Market Operator (**AEMO**)	
Martin Maticka	AEMO	
Zahra Jabiri	Network Operator	
Angelina Cox	Synergy	Proxy for Genevieve Teo
Paul Keay	Small-Use Consumer Representative	
Noel Schubert	Small-Use Consumer Representative	
Geoff Gaston	Market Customer	
Timothy Edwards	Market Customer	
Patrick Peake	Market Customer	
Wendy Ng	Market Generator	
Jacinda Papps	Market Generator	
Rebecca White	Market Generator	
~~Patrick Peake~~	~~Market Customer~~	
Dimitri Lorenzo	Market Customer	Proxy for Paul Arias
Peter Huxtable	Contestable Customer	
Dora Guzeleva	Observer appointed by the Minister	Proxy for Noel Ryan
Rajat Sarawat	Observer appointed by the Economic Regulation Authority (**ERA**)	

Also in Attendance	From	Comment
Laura Koziol	MAC Secretariat	Observer

Also in Attendance	From	Comment
Shelley Worthington	MAC Secretariat	Observer
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	Observer
Ajith Sreenivasan	RBP	Observer
Tim Robinson	RBP	Presenter
Grant Draper	Marsden Jacob Associates (**MJA**)	Presenter
Andrew Campbell	MJA	Observer

Apologies	From	Comment
Noel Ryan	Observer appointed by the Minister	
Paul Arias	Market Customer	
Genevieve Teo	Synergy	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am with an Acknowledgement of Country. The Chair advised that her position as expert panel member on the WA Electricity Review Board remains current.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance and apologies as listed above.	
3	**Minutes of Meeting 2022_05_17** The MAC accepted the minutes of the 17 May 2022 meeting as a true and accurate record of the meeting. **Action: The MAC Secretariat to publish the minutes of the 17 May 2022 MAC meeting on the Coordinator's Website as final.**	**MAC Secretariat**
4	**Action Items** The Chair noted there were no open action items.	
5	**Market Development Forward Work Program** The paper was taken as read and the Chair noted that the updates in red were to be reviewed and discussed. The following topics were discussed. • **The Reserve Capacity Mechanism (RCM) Review** To be discussed under agenda item 6(b). • **The Cost Allocation Review (CAR)** To be discussed under agenda item 6(c).	

Item	Subject	Action
6	**Update on Working Groups**	
	(a) AEMO Procedure Change Working Group (APCWG) The paper was taken as read. Mr Sharafi confirmed that there was no AEMO procedure change activity in June 2022.	
	(b) RCM Review Working Group (RCMRWG) The MAC noted the minutes of the RCMRWG meetings on 5 May and 2 June 2022 and the actions of the RCMRWG in response to the MAC feedback from its meeting on 17 May 2022. The papers for agenda item 6(b) were taken as read. Ms Guzeleva outlined the current stage of the RCM Review work and noted that this was an iterative process and that decisions will only be made once further stages of the work are completed. The key challenge was to get sufficient views, material and modelling results to publish a consultation paper in August 2022. Mr Robinson noted that the purpose of the item was to provide the MAC with the views of the RCMRWG, and to identify what is still controversial and requires further work. Mr Robinson noted that the slides were condensed to the specific design aspects on which feedback was sought and that details were provided in the appendices. Mr Robinson asked the MAC to note: • additional system stress modelling has been undertaken and results will inform proposals for the future of the RCM; • the rationale for a potential new flexible capacity product; and • Certified Reserve Capacity (**CRC**) allocation requires further work, but the RCMRWG is currently seeking buy-in from the MAC on the options to be considered. Mr Robinson noted that the system stress modelling so far has focused on the potential for lost load and did not account for economics. The next stage will be a dispatch model looking at the economics of the various types of technology and retirement. This second stage will test: • the economic implications on particular technology types; • what this might mean for the future of the fleet and retirements; and • whether multiple capacity products are required. Mr Robinson noted that the recent government announcement regarding Synergy plant closures falls within the bounds of the current scenarios (slide 7) and noted that the announced closures will be incorporated into the next stage of modelling. Mr Sharafi noted that there appeared to be a capacity shortfall in 2027-28 and asked whether this was being explored. Mr Robinson advised that there was no specific modelling for 2027-28.	

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	Mr Robinson noted the first principles for the RCM are to ensure acceptable reliability of electricity supply at the most efficient cost. The RCM was originally designed to address peak demand, but by 2050 the question of minimum load and other aspects of reliability of supply will start to matter more. • Mr Robinson sought feedback on whether the MAC agreed with the RCMRWG recommendation to retain the two existing limbs of the planning criterion: peak load and expected unserved energy (**EUE**) % (slide 11). o Mr Sharafi confirmed support in retaining both limbs of the planning criterion and expected further details to explore the interaction between effective load carrying capability (**ELCC**) and planning criteria. o The Chair noted retaining two limbs in the planning criterion appeared to be a non-controversial issue. o Mr Edwards requested to see more detail. o Ms Guzeleva (as Chair of the RCMRWG) confirmed that this was not a controversial issue. The remaining issue was to further analyse the level of the EUE, currently at 0.002% and noting that the Reliability Panel in the National Energy Market (**NEM**) had issued a draft paper that suggested it may be revised in the NEM and that more modelling needs to be undertaken. o The Chair noted that the two limbs are non-controversial, but the level at which they are set may require more discussion. o Mr Schubert noted that, out of all the options the RCMRWG was presented with, retaining both limbs was the best option. Mr Robinson compared the NEM reliability review and the work done to date for the Wholesale Energy Market (**WEM**) (slide 12). • Mr Robinson noted that the WEM seems to have shorter and shallower outages. • The Chair noted that there was support for changing the standard in the NEM and asked if this might be an option in the WEM. • Mr Robinson noted that one of the core principles of the reform was to *not* make it less reliable than it is today. Based on this principle, the 0.002% standard would be retained even if the analysis suggested that it could be reduced to 0.004% or 0.005%. If the analysis indicates that there is economic benefit to a lower standard, then it is a policy call on whether that trade-off has been well enough justified. RBP's recommendation from a consulting perspective would be if there is a benefit and we are confident in the modelling, that will be sufficient to support change. Mr Robinson noted the planning criterion includes a buffer to account for the spinning reserve at the size of the largest unit, but that the RCMRWG agreed that the planning criterion should instead be tied to	

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	the size of the largest contingency, and that the RCMRWG agreed that the change to the planning criterion should be made prior to completion of the RCM Review so that it can be implemented for the next capacity cycle (slide 13). Mr Robinson asked the MAC whether it agrees with the RCMRWG's recommendations. • Mr Schubert, noted this was also discussed by the Expert Consumer Panel and he understood the reason for the largest contingency in the reserve margin, but that he considered the reserve margin should be the biggest contingency at the time of the peak demand. Mr Robinson agreed that was correct. • Mr Sharafi noted that AEMO agreed that planning criteria should consider network contingency as a priority action. AEMO would like to know the timing of any rule changes to address this matter. • Ms Guzeleva indicated that, if MAC agreed to changing the planning criterion as soon as possible to reflect the largest contingency, then it would be included in Tranche 6 changes to the WEM Rules for consultation and then provided to the Minister for approval in November 2022. • Ms Jabiri advised that she was expecting to receive internal feedback and requested to reserve the right to come back with Western Power's position. o The Chair advised that what the MAC decides today is the way in which the work will move forward and asked Ms Jabiri to provide the feedback as a matter of urgency. Ms Jabiri agreed to provide the feedback by the end of the day. • Mr Robinson advised that feedback would be appreciated sooner rather than later, noting that he would be surprised if it would affect Western Power, other than the processes Western Power already have in place to work with AEMO on working out what the contingencies are. • Ms Ng noted that she had no issue with the reserve margin or with making the changes ASAP, and asked if spinning reserve is still going to be procured at 70% of the largest contingency. o Mr Robinson noted that this will be the case until the start of the new market, but it will change after that. o Ms Guzeleva indicated that there would be a refresh of the planning criterion for the 2023 reserve capacity cycle so that margin become the largest contingency, at peak. Mr Robinson noted that the modelling indicated the need for a flexible capacity product because significantly higher ramping would be required – greater than 2,000 MW per hour, which is three times the current rate, and that AEMO has voiced concern that the ramping requirement could be even higher by 2050. Mr Robinson indicated that, with the planned closure of coal and gas plants, it is more of a	

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challenge to be confident that the types of technology required to meet that ramp will be in place when needed.

Mr Robinson noted that the RCMRWG discussed three options:

- retaining the existing planning criteria;
- introducing a specific flexibility capacity product with a new limb to the planning criterion to explicitly allow for payment for a different type of capacity, if needed; and
- introduce a new capacity service for each of the Frequency Co-Optimised Essential System Services (**FCESS**) to make certain that the capacity to provide each services is available in real time.

Mr Robinson indicated that the first two options would be explored in the next stage of modelling. The third option was ruled out due to its complexity.

- Mr Sharafi noted that a reserve capacity megawatt could no longer be defined as it had been previously and agreed that incentivizing the entry of flexible capacity should be a critical part of the review and asked what modifications were expected. Mr Sharafi indicated that AEMO's recommendation is that the complexity of any flexible capacity products should be considered carefully and advised that AEMO would like to be closely involved in considering the design options. Mr Robinson agreed, noting there would be more detail to come in the next stage.
- Ms Guzeleva noted three points that need to be considered:
  - if a second capacity product is required;
  - if so, would it need to be remunerated separately; and
  - how to avoid gaming in the market.

  Obligations, certification and requirements for that capacity product would need to be developed in the second stage of the review.
- The Chair noted the MAC supported moving ahead with economic modeling of a scenario with a single capacity product and a scenario with two capacity products, and considering the design for the new product in the next stage of the review.

Mr Robinson noted that consideration would be given to defining the new product and how the requirement would be set, and indicated that the RCMRWG had discussed two options (slide 17):

- the difference between the minimum load and the peak load (e.g. the total size of the afternoon ramp); and
- an option to find the steepest part of the ramp, although the details of how to define this still need to be determined.

Mr Robinson noted that:

- operational load is key because it represents what you do not have control over; and

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	• it is important to use the 10% POE load forecast to be consistent with the measure used for the peak capacity product. Mr Robinson noted the target for the flexibility product would need to be defined to exclude any intermittent generation that had been curtailed in the middle of the day, but that the RCMRWG had not discussed this matter. • Mr Sharafi noted that AEMO provides a single 10% or 50% POE from which the historical load profiles are scaled up to match peaks and that careful consideration will need to be given to construction of the load profile that sets any target for flexible capacity product, which will be sensitive to the method used to construct it. Mr Robinson agreed and noted that this is the same issue with the overall load forecast. • Mr Schubert supported the proposal and noted the difficulty in defining the steepest ramp because the minimum demand may be in a different part of the year from the maximum demand. • Mr Edwards supported exploration of flexible capacity product because it might incentivize projects to add more solar and storage at a larger scale, which will add diversity over the large amount of wind generation that is expected in the future. • Mr Edwards also noted that simplicity for the product will help preventing gaming of the system. • Mr Maticka noted that there is volatility within the day and that the steepest ramp may be at different times in the day, and asked if this is being considered. Mr Robinson indicated that analysis will be done to determine whether procuring capacity to meet the ramp capability being discussed here would also be sufficient to meet wind/solar volatility at other times. • Regarding treatment of curtailed intermittent generation, Mr Sharafi noted the approach to intermittent facilities relies on foresight of capacity associated with intermittent generation, and that this is not known when AEMO develops the ESOO. Mr Sharafi noted two options: o direct participation of intermittent resources as flexible capacity providers (e.g. de-rating according to how much they may be capable of curtailing); or o the response of curtailed intermittent resources subtracted from the ramping requirements. Mr Robinson agreed that there is a timing question of whether AEMO will have the information it requires at the time it is needed. Mr Robinson noted that facilities could be certified without knowing the targets but that defining the target should be done contemporaneously with allocating capacity credits. Mr Robinson noted that direct participation by intermittent generation in providing the flexibility product is possible – the CRC for those	

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	facilities in terms of the peak product should have already de-rated them for what their reliable output is likely to be at peak. • Ms Guzeleva noted that, if capacity certified for the peak product provides the AEMO with sufficient flexibility, then AEMO would not need to procure more flexible resource. Ms Guzeleva noted it was to be determined how the flexibility product is to be remunerated to avoid gaming opportunities. • The Chair noted the MAC was in agreement with the recommendation for the flexible capacity target to be based on the steepest ramp. • Mr Robinson noted two main feedback points from the MAC that need to be addressed: o the need to make sure that the timing works; and o allowing the intermittent generation to participate in the flexibility product to provide incentive for them to use that capability. Mr Robinson noted that the current availability classes do not capture the capabilities that will be important in the future. It is proposed to replace availability classes with capability classes based on firmness of the capacity, such as: • Class One: unrestricted firm capacity (no fuel/availability limitations – this would include current scheduled generators); • Class Two: restricted firm capacity (with fuel/availability limitations – this would include batteries and DSPs); and • Class Three: non-firm capacity (intermittent generators with no firming components). Mr Robinson noted the RCMRWG supported this proposal but had some reservations that still need to be addressed about: • the detail regarding the impact of new entrants in Class One on the capacity credits for existing Class Two or Three facilities. Mr Robinson noted that Ms Guzeleva acknowledged the need to provide Market Participants some certainty for investment in Class Two facilities. • Providing priority to Class One over Classes Two and Three, given that Class One is likely to be fossil fueled and Classes Two and Three are likely to be intermittent, which may lead to under-procuring renewable energy. Regarding the capability classes: • The Chair sought to clarify that renewables plus storage could fit into Class One or Class Two. Mr Robinson agreed that was correct. • Ms White supported the proposal but indicated that it should be clear that the classes are not just about procuring more firm	

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capacity but also about not limiting participation of renewable energy facilities.

- Mr Sharafi noted that AEMO was supportive of updating the capacity classes to reflect the capabilities but was concerned about the potential complexity. Mr Sharafi sought to clarify:
  - how the classes would apply to peak capacity and what target would need to be met by each capacity class
    - Mr Robinson indicated that there would be one target for the peak capacity product and the classes would form a queue and facilities in each class would be allocated credits in order, with no credits being provided to Classes Two or Three if Class One met all of the peak capacity requirements.
  - how the classes would be applied to the components of hybrid facilities.
    - Mr Robinson noted that this still needs to be addressed, but the options are to certify each component or to certify the facility as a whole, and that this may come down to the choice of the participant depending on which option provides them with the best financial outcome.
- Mr Peake noted that it was indicated at the 24 June 2022 Transformation Design and Operation Working Group (**TDWOG**) that the obligation hours for storage could be increased from four hours, which could destroy incentives for investment in storage.
  - Mr Robinson noted that this was a fair point and that the next slide referred to availability obligations and that they do need to be set in advance.
  - Ms Guzeleva noted that the four hours obligation for storage is set in the Rules and cannot be changed without a rule change, but that AEMO can change the time of day for the four hour period by publishing a notice. Ms Guzeleva noted that the Coordinator is required to review the obligation period and the linear de-rating methodology for storage within five years.
  - Ms White supported Mr Peake's comments.
- Ms Guzeleva noted Mr Sharafi's comment about complexity and indicated that this may lead to describing the facilities that fall within each class rather than having another dimension of assessment in the certification process based on firmness.
- Mr Schubert noted that we should not limit thinking about storage as being only four or five hour batteries, because there is longer term storage like pumped hydro. Mr Robinson noted there may be ways to order capacity within the classes as well.
- The Chair noted that the MAC supported the capability classes and that there is a need to continue to think about the incentives

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sent by the changes, to ensure the delivery of the lowest cost product and not artificially preventing new technologies from participating in a market.

Mr Robinson noted that changes can be made to the availability obligation hours, from the current 24/7 obligation, to more targeted hours, signalled in advance, covering the evening and morning peak, and with different obligations for the peak and flexibility products (slides 20 and slide 77). Mr Robinson sought support for working on these changes, but noted that work needed to be done on what the obligations would be.

- Mr Schubert supported the view.
- The Chair noted that the NEM is looking at a 24/7 obligation and asked why we would use a different approach for the WEM.
- Ms Guzeleva noted that the obligation hours would be linked to the capability classes, and that firm capacity would need to be available all the time, and that we need to be very careful not to water down obligations for fuel requirements.
- Mr Sharafi noted that it is becoming harder to understand when the load is participating more actively, which impacts AEMOs ability to manage these obligations, and the increasing uncertainty will add risk for the accuracy of obligation hours. Mr Robinson agreed that this would suggest a wider obligation.

Mr Robinson noted that CRC allocation methods will continue to be controversial (slide 22) and that the RCMRWG was concerned with the complexity and volatility of some options. Mr Robinson indicated that, following RCMRWG discussions, three options are being assessed:

- Option One: ELCC for intermittent generation only;
- Option Two: a probabilistic approach for all capacity; and
- Option Three: a deterministic approach for intermittent facilities and DSPs based on a predetermined set of intervals.

Mrs Papps provided a slide presenting Alinta's view that the Delta Method is complex, is volatile because it relies on a small sample size, and does not accurately measure reliability of intermittent generators. Ms Papps supported considering the third option.

- Mr Sharafi indicated that AEMO supports the ELCC approach and would like the design to be simple and transparent.
- In response to a question from Ms White, Mrs Papps advised that Alinta is modelling option three and would share the results in the near future.
- Ms Cox noted that Synergy agrees that alternative approaches need to be considered and that Synergy had provided comments to EPWA by email.
- Ms Guzeleva encouraged stakeholders to come up with credible alternatives because time was of the essence.

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	Mr Robinson indicated that work is still underway to decide on the installed capacity (**ICAP**) or unforced capacity (**UCAP**) approach, and invited MAC members to advise whether they had a preference. • Ms Ng and Mrs Papps indicated that they do not support UCAP. The Chair noted that RBP will investigate the pros and cons of ICAP and UCAP to address the specific concerns raised and will consider this against the WEM objectives. Mr Robinson noted that the Benchmark Reserve Capacity Price (**BRCP**) will be discussed at the RCMRWG meeting in July 2022, and Ms Guzeleva indicated that the consultation paper will be discussed with the MAC in August before it is released for consultation. The Chair noted that the MAC generally supported the recommendations in the paper for agenda item 6(b) and that: • further work is to be done on the following items based on feedback from the MAC: o how to specify the ramping requirement; o how curtailment of intermittent generators should be taken into account; o the arrangements for the capability classes; o the options for CRC allocation; • there is a need to be clear about accuracy when we are looking at targeted availability assessment; • Ms Papps will provide further information on an alternative for CRC allocation; and • the pros and cons of ICAP versus UCAP and their impact are to be explained in the consultation paper.	
	ACTION: Ms Jabiri to advise whether Western Power agrees with the RCMRWG's recommendation that changes should be made to the reserve margin before the rest of the change to the RCM.	**Ms Jabiri (29/06/2022)**
	(c) CAR Working Group (CARWG) The MAC noted the minutes of the CARWG meeting and the further updates in the papers for agenda item 6(c), and the Chair indicated the items for which feedback is sought from MAC. As Chair of the CARWG, Ms Guzeleva noted that the CARWG is still in its early days, that no conclusions have been reached, and there will be further discussion with the MAC in October. Mr Draper noted that the next stage for the CARWG is to quantify the impact of the allocation options on market participants and to ascertain the efficiency consequences and equity issues, so guidance is sought on the options to analyse. Mr Draper noted the proposed assessment priorities as follows: • Market Fees was deemed a high priority because the current allocation methodology is only partially aligned with the causer	

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	pay principle and because it has not been reviewed for a long time. • Frequency Regulation was deemed a high priority because the current practice is not aligned with the causer pays principle, which will have consequences from not driving reductions in the costs of providing regulation services. • Contingency Reserve Raise was deemed a low priority because the runway method reasonably aligns with the causer pays principle. • Contingency Reserve Lower was deemed a medium priority because costs are allocated to loads, but not necessarily to large loads, which could be the biggest causers (this will be an emerging issue with the amount of storage coming into the WEM to firm up intermittent energy resources), so consideration could be given to applying a runway method. • Rate of Change of Frequency (**RoCoF**) has not been ranked because the magnitude of this service and its consequences are unknown, but this will not be a focus because it has been recently reviewed by the Energy Transformation Strategy Taskforce. • Black Start was deemed to not require any further assessment. • Non-co-optimised Essential System Services (**NCESS**) for network purposes was deemed to not require review because it is aligned with the causer pays principle. • Fast Frequency Response (**FFR**) is a temporary service, so it will not be assessed at the current time. Mr Draper indicated that analysis of Market Fees would consider the existing methodology, the NEM methodology, and a hybrid approach based on MW and MWh. • Ms White raised concerns with an allocation based on NMIs because this would be inequitable for generators with multiple connections, and would be complex for embedded networks. • The Chair noted that the outcomes of the analysis are important, but recommendations need to consider efficiency principles. Ms Guzeleva noted that CAR has a set of guiding principles that will provide the basis of the analysis. • The MAC supported the options for analysis of Market Fees. Mr Draper sought support from the MAC for prioritisation of the assessment of ESS charges. • Mr Schubert noted the Runway Method for Contingency Raise should include network contingencies. • Ms White noted that the Energy Transformation Taskforce reviewed Frequency Regulation and Contingency Lower in its paper on market settlement in 2019 (Market settlement (www.wa.gov.au).	

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	• Mr Maticka supported the high priority for Market Fees and Regulation, agreed that Contingency Reserve Lower should be next, and agreed that more data was required for RoCoF. • The Chair noted that the MAC generally supported the proposed priorities for analysis of ESS cost allocation. Mr Draper noted that the next steps are moving into the practicality assessments. Ms Guzeleva, noted the next related MAC meeting was in October 2022 where the consultation report would be discussed.	
7	**Rule Changes** **(a) Overview of Rule Change Proposals** The Chair noted one update to the *Wholesale Electricity Market Amendment (Network Access Quantities Procedure) Rules 2022* that will commence on 1 September and 23 March 2023.	
8	**General Business** No general business was raised. The next MAC meeting is scheduled for 23 August 2022.	

The meeting closed at 11:35 am.

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 2022_08_23

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
1/2022	MAC Secretariat to publish the minutes of the 28 June 2022 MAC meeting on the Coordinator's Website as final.	MAC Secretariat	2022_06_28	**Closed** The minutes were published on the Coordinator's Website on 29 June 2022.
2/2022	Ms Jabiri to advise whether Western Power agrees with the RCMRWG's recommendation that changes should be made to the reserve margin before the rest of the change to the RCM.	Ms Jabiri	2022_06_28	**Closed** A confidential response was received 29 June 2022.

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

Agenda Item 5: Market Development Forward Work Program

Market Advisory Committee (**MAC**) Meeting 2022_08_23

1. Purpose

- To provide an update on the Market Development Forward Work Program provided in Table 1, including:
    - the Chair of the Reserve Capacity Review Working Group (**RCMRWG**) is to update the MAC on the work done by the Working Group to date – see Agenda Item 6(b);
    - the MAC is asked to review the draft Reserve Capacity Mechanism Consultation Paper – see Agenda Item 8; and
    - the Chair of the Cost Allocation Review Working Group (**CARWG**) is to update the MAC on the work done by the Working Group to date – 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:
    - No updates.
- 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.

3. Process

Stakeholders may raise issues for consideration by the MAC at any time by sending an email to the MAC Secretariat at energymarkets@energy.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. Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group, including: o the Scope of Works for the review, as approved by the Coordinator; o the Terms of Reference for the Working Group, as approved by the MAC; o the list of Working Group members; o meeting papers and minutes from the Working Group meeting on 20 January 2022 and 17 February 2022; o meeting papers for the Working Group meeting on 17 March 2022, 5 May 2022; o meeting papers and minutes from the Working Group meeting on 2 June 2022; and o meeting papers from the Working Group meeting on 16 June 2022. • The Chair of the Working Group will update the MAC on the work done by the Working Group to date – see Agenda Item 6(b). • The MAC is asked to review the draft Reserve Capacity Review Consultation Paper – see Agenda Item 8.
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	• The MAC has established the Cost Allocation Review Working Group. Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group, including: o the Scope of Work for the review, as approved by the Coordinator; o the Terms of Reference for the Working Group, as approved by the MAC;

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
	• Issues 2, 16, 23 and 35 from the MAC Issues List (see Table 3).	o the list of Working Group members; and o meeting papers and minutes from the Working Group meeting on 9 May 2022; and o meeting papers from the Working Group meeting on 7 June 2022. • EPWA has engaged Marsden Jacob Associates for the consultancy services to assist with the Cost Allocation Review. • The Chair will update the MAC on the Working Group's progress to date – see Agenda Item 6(c).
Procedure Change Process Review	A review of the WEM Procedure Change Process to address issues identified through Energy Policy WA's consultation on governance changes.	• This review will commence in 2023.
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.

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 well 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, 23 August 2022

FOR NOTING

SUBJECT: UPDATE ON AEMO'S MARKET 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	30 November 2021	TBC
Market Procedures for discussion	Market Procedure: Prudential Arrangement	TBC

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 23 August 2022. 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**
None				

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

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

Market Advisory Committee (**MAC**) Meeting 2022_08_23

1. Purpose

- The Chair of the Reserve Capacity Review Working Group (**RCMRWG**) is to update the MAC on the activities of the RCMRWG since the last MAC meeting.
- The MAC is to note:
  - the update on the RCMRWG; and
  - that the RCMRWG's discussion at the working group's meetings on 14 and 21 July 2022, which has not yet been discussed with the MAC, is reflected in the conceptual design proposals in the Reserve Capacity Mechanism (**RCM**) Review consultation paper to be discussed under agenda item 8.

2. Recommendation

That the MAC notes:

(1) the minutes from the RCMRWG meetings on 6 June, 14 July and 21 July 2022; and

(2) that the conceptual design proposals in the draft RCM Review consultation paper to be discussed under agenda item 8, have been developed considering the discussions at the RCMRWG and the MAC to date.

3. Process

- Outcomes from 2 and 16 June 2022 RCMRWG meetings were presented at the 28 June 2022 MAC meeting, when the MAC:
  - discussed the additional system stress modelling and the RCMRWG's feedback on these results; and
  - supported the preliminary directions, including:
    - retaining the two existing limbs of the Planning Criterion: peak load and expected unserved energy (**EUE**) %;
    - changing the reserve margin definition ahead of the rest of the RCM;
    - comparing a continuation of the current single-product RCM with a two-product RCM with separate targets for peak capacity and flexible capacity;
    - setting a flexible capacity target based on the steepest ramp;
    - replacing availability classes with capability classes based on firmness of the capacity;
    - undertaking further modelling on the options for allocating Certified Reserve Capacity (**CRC**);

        - assessing the impact of using the installed capacity (**ICAP**) or unforced capacity (**UCAP**) on system reliability and on the overall cost of reserve capacity procurement.
    - advised that the following further work is to be undertaken:
        - how to specify the ramping requirement;
        - how curtailment of intermittent generators should be taken into account;
        - the arrangements for the capability classes; and
        - the options for CRC allocation.
- Minutes from the 2 June 2022 RCMRWG meeting were provided at the 28 June 2022 MAC meeting.
- Minutes from 16 June 2022 RCMRWG meeting are attached (**Attachment 1**).
- Minutes from 14 July 2022 RCMRWG meeting are attached (**Attachment 2**). At this meeting, the RCMRWG discussed the Benchmark Reserve Capacity Price (**BRCP**) and incentivising capacity that can cover a flatter and longer system peak (duration gap), including:
    - the requirement for two BRCPs – one for the current peak capacity product and one for the flexibility capacity product.
    - the need for the RCM to provide a signal for addressing the growing duration gap;
    - the conceptual design for three capability classes proposed to replace the current availability classes:
        - Class 1: unrestricted firm capacity;
        - Class 2: restricted firm capacity; and
        - Class 3: non-firm capacity (intermittent generators)
    - the need to consider the impacts of changing availability hours on investment.

  Note: the slides that were presented were updated from those that were distributed to the RCMRWG before the meeting. Updated slides are published on the RCMRWG webpage.
- Minutes from 21 July 2022 RCMRWG meeting are attached (**Attachment 3**). At this meeting, the RCMRWG discussed two alternative methods for assigning CRC for intermittent generators developed by Collgar and Alinta Energy individually.

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-working-group.

Attachments

(1) RCMRWG 2022_06_16 – Minutes of Meeting

(2) RCMRWG 2022_07_14 – Minutes of Meeting

(3) RCMRWG 2022_07_21 – Minutes of Meeting

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	16 June 2022
Time:	9:30am – 11:30am
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Rhiannon Bedola	Synergy	
Oscar Carlberg	Alinta Energy	Proxy for Jacinda Papps
Peter Huxtable	Water Corporation	
Dimitri Lorenzo	Bluewaters Power	Proxy for Paul Arias
Mark McKinnon	Western Power	
Wendy Ng	Shell Energy	
Patrick Peake	Perth Energy	
Toby Price	AEMO	Proxy for Manus Higgins
Richard Cheng	Economic Regulation Authority	Proxy for Matt Shahnazari
Noel Schubert	Small-Use Consumer representative	
Andrew Stevens	Clear Energy	
Dev Tayal	Tesla Energy	
Andrew Walker	South32 (Worsley Alumina)	
Rebecca White	Collgar Wind Farm	
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	
Ajith Sreenivasan	RBP	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	
Shelley Worthington	EPWA	

Apologies	From	Comment
Paul Arias	Bluewaters Power	
Manus Higgins	AEMO	
Jacinda Papps	Alinta Energy	
Matt Shahnazari	Economic Regulation Authority	
Dale Waterson	Merredin Energy	

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	**Minutes of RCMRWG meeting 2022_06_02** Draft minutes of the RCMRWG meeting held on 2 June 2022 were distributed on 13 June 2022. Mr McKinnon asked to include his comment that 41°C may no longer be appropriate as a basis for the Reserve Capacity Mechanism (**RCM**). Mr McKinnon noted that 41°C is not only the basis for assessing generation capacity but also for setting the RCM Limit Advice. Ms Koziol requested that any further comments on the 2 June 2022 minutes should be provided by close of business 16 June 2022. The RCMRWG accepted the minutes as a true and accurate record of the meeting, pending the amendment to reflect Mr McKinnon's comment and any further comments provided on 16 June 2022. **Action: RCMRWG Secretariat to publish the minutes of the 2 June 2022 RCMRWG meeting on the RCMRWG web page as final.**	**RCMRWG Secretariat**
4	**Action Items** The paper was taken as read.	
	The slides for agenda items 5 to 8 are available on the webpage for the RCM Review (https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group).	
5	**Project Timeline** Mr Robinson presented the timeline.	
6	**Updated System Stress Modelling Outputs** Mr Bowmaker presented the options for assessing resource adequacy (slides 8 to 28). The following issues were discussed:	

Item	Subject	Action

	Government announcement about plant retirement
	• Mr Bowmaker noted that, on 14 June 2022 the WA Government announced its plans to:
	  ○ retire Synergy's coal fired power plants by 2030;
	  ○ assess network augmentation; and
	  ○ invest in wind energy and storage capacity including long-term storage.
	• Mr Bowmaker noted that the R1 scenario of the system stress modelling is now obsolete but the R2 scenario is still relevant as it incorporates the announced retirements.
	• Mrs Bedola suggested to revise the R1 scenario to reflect the announced retirements.
	• Mr Bowmaker noted that because the R2 scenario reflects the announced retirements, R1 will only be adjusted for the economic modelling in step 5 of stage 1 of the review.
	• In response to a question from Mr Carlberg, Mr Bowmaker clarified that, under the R2 scenario, all baseload thermal generators including coal and gas fired baseload plants will be retired by 2030 but other gas plant will still operate.
	• In response to a question from Mr Schubert, Mr Bowmaker confirmed that the Government's announcements about investments in renewable generation and storage will be taken into account in the next round of modelling.
	• Mr Schubert noted the 2022 WEM Electricity Statement of Opportunities (**ESOO**) is about to be published and asked whether the modelling assumptions for the RCM Review will be updated to reflect the ESOO. Mr Robinson indicated that the 2022 ESOO will be reviewed to assess whether it is consistent with the RCM Review assumptions or whether there are any significant differences.
	Updated system stress modelling
	• Mr Robinson clarified that the capacity needs identified by the system stress modelling are based on the specified expected unserved energy (**EUE**) and that additional capacity may be needed to satisfy the peak demand limb of the Planning Criterion.
	• Mr McKinnon clarified that, in reality, the operational load will never become negative and suggested to use different terminology. Mr McKinnon asked whether the projected demand will be affected by the measures taken to address the negative load.
	• In response to a question from Ms White, Mr Sreenivasan clarified that the assumptions include optimisation for charging of electric vehicles (**EV**) at times of system peak for the 2030 and 2050 scenarios and that the effect of EVs on system load is small in the 2030 scenarios because of the small number of expected EVs.	

Item	Subject	Action
	• In response to a question form Mr Price, Mr Sreenivasan clarified that the charging scenario from the 2021 ESOO was used for the base case and that additional charging optimisation had been applied. Western Power's assumptions on EV charging are reflected to the extent that they align with the assumptions in the 2021 ESOO. • In response to a question from Mrs Bedola, Mr Bowmaker clarified that the demand response in the scenarios does not refer to the effect of Demand Side Programs referred to in the current WEM Rules. • Mr Carlberg considered that the 2021 ESOO's peak demand forecast is too low because the 10% probability of exceedance (**POE**) of peak demand had been exceeded several times. Mr Carlberg considered that peak demand may increase quicker than forecast in the 2021 ESOO due to climate changes. Mr Robinson noted that it will be assessed whether the RCM Review assumptions are consistent with the 2022 ESOO. Ms White asked whether the Planning Criterion should be moved to cover 5% POE to address the increasing peak demand. The Chair noted that a 5% POE peak demand target would be too expensive and that the focus should be for an appropriate forecast of the 10% POE peak demand. • In response to a question from Mr Tayal, Mr Robinson confirmed that the modelling assumptions included that the generators would meet their availability obligations. The Chair noted that generators are subject to Reserve Capacity Refunds if they don't meet their availability obligation. • In response to a question from Mr McKinnon, Mr Bowmaker clarified that: o the ramping needs assessed are based on the modelled operational demand, which includes assumptions about generation from distributed energy resources (**DER**); and o only ramping from Trading Interval to Trading Interval is considered, not intra-interval ramping caused by the fluctuation of intermittent generation, which is assumed to be met by the Essential System Services (**ESS**) market. • Mr Robinson noted that the current proposal is to include a flexibility product. Mr Robinson considered that if sufficient ramping capacity is available to address demand ramping, it will also be sufficient to address intra-interval variability of intermittent generation. Mr Robinson noted that this will be further assessed to confirm the assumption. • In response to a question from Mr Price, Mr Robinson noted that the numbers for the needed capacity in the table on slide 20 refer to absolute capacity and not additional capacity needed.	

Item	Subject	Action
	• In regards to the charts on slide 21, Mr Carlberg asked whether the high number of loss of load hours (**LOLH**) at 9:00pm are caused by the assumption that electricity storage resources (**ESR**) will not be required to be available at that time because this is outside of the Electric Storage Resource Obligation Intervals (**ESROI**). Mr Schubert considered that the assumptions on EV charging will drive at what time the modelling identifies LOLH. In response to a question from Mr Cheng, Mr Robinson confirmed that the results indicate a need for long duration storage. • Mr Schubert considered that EV charging during the evening peak will be an indicator that the incentives to move charging from the evening peak are insufficient. The Chair agreed that introducing automated staggered EV charging will be important. Mr Robinson noted that some EV charging decisions will be made by consumers and some by aggregators and that some of the charging can be shifted by demand response incentives. Mr Robinson noted that the modelling assumptions were between assuming no measures and perfect measures to shift EV charging after the peak hours. The Chair considered that the modelling should include an assessment of what will happen if there are no measures to shift EV charging to after the peak. Mr Robinson agreed to model this as an additional scenario and noted that there are already incentives for retailers to shift the EV charging to after the peak, such as the Individual Reserve Capacity Requirement (**IRCR**). Several RCMRWG members considered that tariff changes to shift EV charging is unlikely. The Chair considered that the introduction of standards and automation will be important to address timing for EV charging. • Mr Schubert considered that the current IRCR may not incentivise Synergy to reduce consumption during peak. Mrs Bedola noted that customers with distributed PV (**DPV**) are reducing system peak demand while shifting system peak to later in the day but they get no benefits in terms of a reduced IRCR. • Ms White asked if changes in the ESROI would materially affect the modelling results. Mr Sreenivasan noted that, for 2050, the modelling was assuming different ESROIs based on the observed operational demand. The Chair noted that the length of the ESROI can be increased following the relevant review prescribed under the WEM Rules. Mr Schubert considered that long-term storage should be available by 2050.	

Item	Subject	Action
7	**Planning Criterion** Mr Robinson presented the proposal for amending the Planning Criterion (slides 30 to 32). The following issues were discussed: **Reserve margin** • Mr Carlberg considered that the forced outage rate may become less relevant for the reserve margin with a higher share of intermittent generation and Synegy's coal fired power plants retiring. Mr Carlberg considered that the errors of demand forecast and intermittent generation forecast may become the main driver for the reserve margin. • Mr Robinson suggested that a principles based approach could be used to set the reserve margin instead of a fixed percentage. The Chair considered that the reserve margin must strike the right balance between system adequacy and cost to consumers. If the reserve margin is not fixed in the rules, then guidance for AEMO and strict scrutiny rules will be important to ensure the right balance. • The Chair clarified that, at a minimum, the reserve margin should be set by the largest contingency, including network outages, and not by the largest generation unit. • Mr Schubert considered that, when assessing the north country as the largest network contingency, it should be recognised that the north country generators may not have the highest output at times of system peak. • The Chair agreed that the largest contingencies may not happen during system peak demand and suggested that the reserve margin should be set probabilistically based on the largest contingency expected at times of system peak demand. **Introduction of a flexibility capacity product** • Ms White noted that the target for the flexibility product should consider the time difference between daily minimum and maximum demand and not only the MW difference of the two. • In response to a comment form Mr Schubert, Mr Robinson noted that setting the target for the flexibility product may need to be refined to reflect the duration and steepness of the ramp because the difference between daily minimum demand and peak demand may overstate the need for flexibility. • In response to a question from Mr Price, Mr Robinson clarified that the suggestion is to have one requirement for the peak demand and EUE and another requirement for the flexibility product. • Mr Schubert considered that the RCM needs to ensure that enough flexible capacity and enough capacity for peak is procured, but must avoid doubling up on capacity at unnecessarily higher cost. • In response to a question from Ms White, Mr Robinson clarified that the suggestion is to have two capacity products with two distinct	

Item	Subject	Action
	prices and that a Facility that can provide both products will receive the uplift payment for the flexibility product. • In response to a question form Ms White, Mr Robinson summarised that the following capabilities are expected to be part of the defined flexibility product: ○ fast start capability; ○ low availability restrictions, such as minimum generation; and ○ fast ramping capability. • Mr Robinson clarified that inertia is not planned to be included in the flexibility product, as this is expected to be provided through the ESS market. The Chair noted that it is important to ensure that sufficient inertia is available and that the RCM should not de-incentivise the provision of inertia. • The Chair considered that the flexibility product should be remunerated for facilities that provide both the peak product and flexibility to avoid perverse incentives to withhold capacity. • Mr Schubert considered that procurement of the peak product should not be prioritised over procurement of the flexibility product or vice versa to satisfy both requirements at the lowest cost. • Mr Peake considered that it would be ideal to price every required element needed from facilities and optimise procurement of the lowest cost combination but that this will likely be too complex. • In response to a question of Mr McKinnon, Mr Robinson clarified that the modelling does not consider any DPV that is part of a virtual power plant (**VPP**) as part of the operational load. Mr Price clarified that this concept can only apply for VPPs that are a Small Aggregation under the WEM Rules. Mr Robinson agreed. • The Chair considered that reducing the output of DPV should be avoided were possible by charging ESR instead of DPV curtailment. • Mr Carlberg asked whether the flexibility product is envisioned to be based on the needed ramp rate over a certain time. Mr Robinson agreed that this is the current proposal. • Mr Schubert considered that the needed flexibility product may differ depending on how many facilities can provide it. • The Chair noted that the obligations for the flexibility product will need to be carefully designed to ensure that the flexibility is available when needed. • Mr Robinson noted that the economic modelling will assess whether the peak capacity product may be sufficient to incentivise the needed flexibility without adding a flexibility capacity product. • In response to a question from Ms White, Mr Robinson clarified that he considered that the obligation for providers of the flexibility product will likely include obligations to offer the flexibility at certain times and seek outage approval.	

Item	Subject	Action
	• The Chair noted that sculpted refunds would be preferable for the flexibility capacity product, similar to the current refund regime for the peak capacity product.	
8	**Next Steps** The RCMRWG noted the outstanding items to be resolved on slide 34. The RCMRWG agreed that, based on the discussion, the MAC should be advised that the RCMRWG suggested the following: • retaining the two existing limbs of the Planning Criterion: peak load and EUE; • change the current reserve margin to the largest contingency on the system and make this change ahead of the rest of the changes to the RCM; • compare the continuation of the current single-product RCM with a two-product RCM with separate targets for peak capacity and flexible capacity; and • only procure a flexible capacity product if the need for flexibility is not met by the capacity needed to fulfill the peak capacity requirement.	
9	**General Business** No general business was discussed.	

The meeting closed at 11:30am.

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	14 July 2022
Time:	9:30am – 11:30am
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	From 9:45am
Rhiannon Bedola	Synergy	
Manus Higgins	AEMO	
Toby Price	AEMO	
Jacinda Papps	Alinta Energy	
Peter Huxtable	Water Corporation	
Paul Arias	Bluewaters Power	
Mark McKinnon	Western Power	From 10:15am
Patrick Peake	Perth Energy	
Matt Shahnazari	Economic Regulation Authority	
Richard Cheng	Economic Regulation Authority	
Noel Schubert	Small-Use Consumer representative	
Andrew Stevens	Consultant	
Rebecca White	Collgar Wind Farm	
Wendy Ng	Shell Energy	
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	
Ajith Sreenivasan	RBP	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	
Shelley Worthington	EPWA	

Apologies	From	Comment
Dev Tayal	Tesla Energy	
Andrew Walker	South32 (Worsley Alumina)	

Apologies	From	Comment
Dale Waterson	Merredin Energy	

Item	Subject	Action
1	**Welcome** Ms Koziol opened the meeting at 9:30am.	
2	**Meeting Apologies/Attendance** Ms Koziol noted the attendance as listed above.	
3	**Minutes of RCMRWG meeting 2022_06_16** Draft minutes of the RCMRWG meeting held on 16 June 2022 were distributed on 7 July 2022. The RCMRWG accepted the minutes as a true and accurate record of the meeting. Mr Shahnazari noted that the RCMRWG seemed to form a view at its meeting on 7 July 2022 that the Reserve Margin is to account for the largest contingency on the system. Mr Shahnazari expressed the view that this might lead to double counting and that the Reserve Margin is instead intended to account for uncertainty in forecasting 10% POE of peak demand.	
	Action: RCMRWG Secretariat to publish the minutes of the 16 June 2022 RCMRWG meeting on the RCMRWG web page as final.	**RCMRWG Secretariat**
4	**Action Items** The paper was taken as read.	
	The slides for agenda items 5 to 9 are available on the webpage for the RCM Review (https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group).	
5	**Project Timeline** Mr Robinson presented the timeline and noted that an additional RCRMRWG meeting was scheduled for 21 July 2022 to discuss CRC allocation and that the next step is publication of the consultation paper.	
6	**BRCP for the Peak Capacity Product** Mr Robinson led discussion on the Benchmark Reserve Capacity Price (**BRCP**) for the peak capacity product (slides 7 to 12). The following issues were discussed: • Mr Robinson recapped how the current BRCP is set and asked whether the assumptions for this calculation still hold. • Mr Robinson suggested that the WEM Rules should provide guidance on setting the BRCP and that details can be left to a WEM Procedure. • Mr Robinson noted that we need to make sure that revenue streams are available so that the most efficient marginal new entry facility can recover its efficient short run costs in the energy and	

Item	Subject	Action
	Essential System Services (**ESS**) markets and efficient capital costs from the Capacity Mechanism. • Ms Bedola asked how we can ensure that an efficient marginal energy provider can recover its fixed costs. o Mr Robinson noted that any facility that has lower short-run costs than the marginal energy provider will recover some fixed costs from the energy and ESS markets, and that we are seeing investment in renewables even though they have higher capital costs than a 160 MW OCGT – they do not recover all of their capital costs from the Capacity Mechanism and recover some through the energy and ESS markets. o Ms Guzeleva noted that renewables also currently get a subsidy. o Ms Bedola asked about mid-merit plants. Mr Robinson suggested that the question is how mid-merit units will cover their fixed costs in 10 years' time, when the peakers that are currently marginal are no longer providing infra-marginal rents. Mr Robinson suggested that we should not write rules to guarantee that existing plants, which have been in place for some time, can recover their fixed costs. o Ms Guzeleva noted that these units will be needed in the ESS market between now and 2030, when longer duration storage comes on, and that the economic modelling will consider this in the medium term. o Mr Robinson confirmed that the economic modelling will look at whether there are cases where a plant will exit the market or a new entrant of the type we need cannot enter the market because it cannot recover its fixed costs from capacity and energy revenue. • Ms White suggested that we cannot create a market where a generator can only recover its costs if it participates in the ESS market, this would be contrary to the concept of recovering capital costs from the RCM and operating costs from the real time markets. o Ms Guzeleva indicated that ESS is a real time market and that it is expected that the market will shift away from energy to ESS for devices that are capable of providing ESS. o Ms White suggested that each real time market needs to be considered individually – if you are operating in the energy market, you should be able to recover your variable costs from that energy market and should not have to also participate in another real time market to cover variable costs. o Mr Stevens asked if the energy market price caps would be made higher if the BRCP is lowered. ▪ Mr Robinson clarified that energy price caps in the WEM are set low to reflect the existence of the RCM, but are	

Item	Subject	Action
	higher in the NEM, so that participants will sometimes recover more than their short-run costs, even if they are marginal. We need to be aware of the energy price caps when thinking about how facilities can recover various categories of cost. ▪ Mr Stevens pointed out that investment decisions are based on whether a facility can recover its capex against the 160 MW OCGT baseline and what can be recovered in the energy market – there is a relationship between the BRCP and energy price caps and we would ruin the market if the capacity price is set extremely low and the energy price caps do not move to let in participants. Slides 10 and 11 were used to discuss the reference technology for the BRCP (*note: the slides that were presented were updated from those that were distributed to the RCMRWG and the updated slides are now published on the RCMRWG webpage*). • Mr Robinson presented the expected capital costs ($/kW) for various types of technology based on the central and high VRE scenarios from the CSIRO generation cost report. o In the central VRE central scenario, the cost for a four hour battery is already lower than a small OCGT but it will be higher than for a large OCGT for some time. o In the high VRE scenario, the cost of a four hour battery is below even than the large OCGT in 2024, and an eight hour battery will be below the cost of a large OCGT by 2030. o This indicates that batteries are competitive against small OCGTs but it will be some time before they are competitive against large OCGTs. • Mr Robinson indicated that consideration needs to be given to whether an OCGT could credibly be built in the SWIS in the next 5-10 years, noting that none are currently being considered and considering both cost and other aspects, like Government policy (recognizing that Government policy does not prevent building OCGTs). • Mr Robinson noted that a 4 hour battery will currently meet the needs of the SWIS, but we will need 8 hour storage by the 2030s and 16 hours by 2050 to cover the duration gap. o Mr Robinson showed a comparison of the costs over time for small and large OCGTs and for 4, 8 and 16 hour batteries, based on CSIRO data. Mr Robinson indicated that, as the type of battery required in the SWIS shifts over time, the cost of batteries may be above or below the cost of a small OCGT, but will likely be higher than the cost of a large OCGT. o Mr Robinson indicated that the WEM Rules do not provide guidance on how to set the BRCP and the proposal is to specify that the BRCP should represent the per MW capex cost	

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	of the new entrant technology with the lowest expected capital, and that the ERA's regular BRCP reviews should determine the reference technology. o Mr Robinson indicated that choosing a higher cost reference technology, while a cheaper technology can be built, would give facilities more contribution to their capital costs through the capacity mechanism than is needed. o Ms White indicated that the Minister has alluded to Synergy needing to build another gas turbine given the coal plant retirements. Ms Guzeleva indicated that the Minister's statement was that Synergy would not build more gas turbines. o In response to a question from Mr Schubert, Mr Robinson indicated that pumped hydro unit costs are higher than batteries. o Mrs Papps indicated that the current BRCP methodology assumes a 160 MW liquid fueled OCGT and asked if this is still the assumption. ▪ Mr Robinson indicated that a big OCGT would need to be 300 MW or more achieve the lower capital costs. ▪ Mr Robinson asked for feedback on whether it was likely that a liquid fueled OCGT was feasible in WA. ▪ Ms Guzeleva indicated that a consultation paper on the market power mitigation review will be published by the end of July 2022 that will propose a single energy cap that will cover the highest marginal cost in the market, which is currently diesel based. • Mr Shahnazari noted that it will be important to consider revenues from participation in other parts of the market when setting the BRCP. • In response to a question from Ms White, Mr Robinson indicated that we will need two BRCPs – one for the peak capacity product and one for the flexibility capacity product, and the same considerations will apply to setting the two BRCPs. • Mr Higgins asked for stakeholder feedback on whether they are experiencing difficulties in securing liquid fuel contracts that can meet the 14 hour fuel requirement for small units? Mrs Papps indicated that she could respond on this separately. • Regarding use of gross or net cost of new entry (**CONE**) in determining the BRCP, Mr Robinson noted that: o the intent is to set the energy price cap so that the highest cost facility in the fleet can recover its short-run costs in the energy market but would not get a contribution to its capital costs; o if an OCGT is the marginal new entrant and is the most expensive provider of energy, then we can rely on gross CONE to set the BRCP; but	

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	o if the marginal provider of capacity no longer has the highest short-run costs in the fleet, then that facility will start getting an additional contribution to its long-run costs from the energy market. • Mr Robinson proposed that: o to simplify the calculations, the rules should specify that the BRCP should be based on gross CONE, so long the marginal capacity provider is also the highest cost energy provider; but o otherwise the rules should prescribe the use net CONE. So we would need to start using net CONE to set the BRCP if batteries become the marginal technology. • Ms Guzeleva pointed out that, apart from the highest short-run marginal cost (**SRMC**) facility, as longs as the price cap is high enough for a facility to recover its SRMC, then it will get a contribution to its capital costs when it runs, in which case there should be no concerns on viability of the facility. Ms Guzeleva noted that the Market Power Mitigation Review proposal is to have a single energy price cap based on diesel generators. • Mrs Papps indicated that it will be difficult to move to a net CONE approach because it is difficult to reconcile the assumed net energy market revenue due to the peakiness in the SWIS and asked how we can deal with this. o Mr Robinson agreed that using net CONE will increase the complexity of setting the BRCP and add forecasting error from the need to forecast energy revenue, but indicated that other jurisdictions have managed to deal with this, and advised that we would overcompensate facilities and distort market signals if we do not use net CONE. o Mrs Papps sought clarity that, when the five yearly review is considering gross versus net CONE, it should also consider the energy price caps to make sure that they are high enough as we approach scarcity. o Mr Robinson suggested that the principle of setting the energy price cap to cover the short-run cost of the most expensive facility can stand regardless of the reference technology that sets the BRCP. • Ms Bedola asked about existing diesel facilities that provide the reserve margin and do not run – if the BRCP is reduced to net CONE for a battery, then how can they cover their fixed costs o Ms Guzeleva indicated that these facilities will make their investment decision based on the 160 MW OCGT BRCP and that the energy price cap would let them cover their operating costs based on diesel fuel. o Mr Robinson pointed out that the use of the facility will be addressed in determining the net CONE – the net CONE for a	

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	facility would not be much different from its gross CONE if it is not used much. This is why the net CONE calculation is more complex. o Mr Stevens pointed out the potential for distortion if someone introduces a very expensive SRMC facility and forces the market to lift the price cap to allow for that unit. ▪ Ms Guzeleva indicated that there should be other measures in the rules to protect against this. ▪ Mr Robinson pointed out that a new entrant facility will not recover its full capital costs if it has higher capital costs than the marginal capacity and its SRMC is at the price cap. A company may do this to increase earnings for the rest of its portfolio, but this is where other market power mitigation measures come into play. ▪ Mr Guzeleva pointed out that the energy price cap is a customer protection measure and is not intended for facilities to bid at the cap. ▪ Mr Stevens and Mr Huxtable raised a concern that a high SRMC facility may be built for non-commercial (green) purposes, which may distort setting the energy price cap. Ms Guzeleva acknowledged this and suggested that a submission could be made to the market power mitigation consultation paper to address this matter.	
7	**BRCP for the Flexible Capacity Product** Mr Robinson led the discussion on the BRCP for the flexible capacity product (slides 13 to 16). • Mr Robinson indicated that: o OCGTs and batteries are likely to be able to be provide the flexible capacity product, and facilities would be overcompensated if we set the BRCP for the flexible capacity product higher than the capital cost of the cheapest unit. o There may be additional costs for providing the flexibility product, so there may be some differences between the reference technology for peak and flexibility products. o The plan is for a future system with no gas-fired facilities, so it could be argued that such plants should be made ineligible for the flexibility capacity, but this is not proposed because there is no policy for the RCM to incentivize low-emissions generation at this stage. o The proposal is to set the BRCP for the flexibility capacity product using the same principles as for the peak capacity product, but accounting for any additional technology investment needed for facilities to provide the flexible service. • Ms Bedola indicated that excluding gas would need to be a government policy decision. Ms Guzeleva agreed.	

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	• Ms Bedola indicated that flexible capacity might be limited by Network Access Quantities (**NAQ**) and Mr Cheng agreed that guidance on NAQs would be useful. o Mr Robinson noted that limited NAQ indicates issues with transmission investment and the RCM is not going to be able to solve the problem if a battery cannot be built anywhere on the network and get NAQs. o Ms Bedola suggested that a battery could be built in a place with network congestion, like Muja, because network capacity will become available in the future with the coal retirements, in which case the battery would not get NAQs for a period but would be dispatched before a constrained coal plant. o Ms Guzeleva indicated that a problem emerges if a 160 MW turbine cannot be located anywhere on the system – this becomes a barrier to that technology, so NAQs need to be considered. • Mr Peak noted that a flexible gas turbine is likely to be aero derivative, which is likely to be smaller and have higher capital costs. Mr Robinson agreed that we need to understand what the flexibility product is and what the lowest capital cost would be for a facility that can provide the service. Mr Robinson led a discussion about the interaction between the peak and flexible capacity products. • Mr Robinson indicated that a facility that provides both peak and flexible capacity will need to be compensated to recover the capital costs for whichever service is more expensive to build. • The proposal is to set the capacity price as follows: o a facility that provides only the peak capacity product will get the peak capacity price; o a facility that provides only the flexibility capacity product with get paid the flexibility capacity price; and o a facility that provides both products will receive the higher of the peak or flexibility capacity price for providing both products. • Mr Price asked, if a facility is providing both products but provides more peak capacity than flexibility capacity, and the price is higher for the flexibility product, would they be paid the higher flexibility price for the peak capacity? o Ms Guzeleva indicated that a tie breaking order would be included in the rules. o Mr Stevens asked, if we have a 200 MW facility that has 180 MW of peaking capacity and 20 MW of flexible capacity, and the flexible capacity price is higher, do we pay all 200 MW at the higher price? o Mr Robinson indicated that this was not the case – the example provided in the slides assumed the facility provides the same	

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	number of MW of each product. The pricing would need to account for any differential in the MW quantity of each product. • Mr Shahnazari asked if we will have one marginal price for peak capacity and another for flexible capacity. o Mr Robinson indicated that we will have a benchmark price for each product and a reference price for each product, and that the rules already provide for different prices for different facilities. o Mr Shahnazari indicated that a market will drive a single marginal price for each product and that infra-marginal rents will drive innovation and efficiency in the market, and suggested that the proposal will deviate from market-based procurement if we have different marginal prices. o Mr Robinson indicated that the RCM is an administered mechanism and Mr Shahnazari suggested that the administered mechanism should emulate competitive outcomes. o Mr Robinson indicated that there will be two price curves – one for each product, so each product will have a marginal price for capacity, and the problem we are trying to address is what to pay a facility that uses the same capacity to provide both products. For example, a 160 MW OCGT that provides 160 MW of peak capacity and 160 MW of flexible capacity should not be paid the 160 MW times the peak capacity price plus 160 MW times the flexible capacity price. o Mr Shahnazari agreed and clarified that his point is that there should be a single price in each market. For example, if we were in a situation where we have lots of peak capacity but need lots of flexible capacity, then the price for the peak capacity should be low and the price for flexible capacity should be high. If we differentiate the price for generators we will deviate from emulating the outcomes of competitive market. o Mr Robinson suggested that, in this situation, a facility that provided both peaking and flexibility capacity should be paid more than a facility that only provides peak capacity. • In response to a question from Ms Papps, Mr Robinson confirmed that the proposal is to have: o different demand curves for each product, but with the same shape; o a different target for each product; and o a different BRCP for each product, likely higher for the flexibility product. • Ms Papps asked how the Individual Reserve Capacity Requirements (**IRCR**) will work and who will pay for the flexible capacity. Mr Robinson indicated that:	

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	o we have a method to allocate the peal capacity product to participants – IRCR – and this will be considered in the next stage of the review; o the way to allocate liability for the flexibility capacity product will also be considered in the next stage of the review; and o we may want to allocate liability for the flexibility product using IRCR – this would be simple but may not be fair – or we may want to allocate it based on consumers' contribution to the speed of the ramp. • Ms Bedola asked if a facility would only be accredited for the flexibility product after its mingen – for example, if a 160 MW OCGT had a 60 MW mingen, would its flexible capacity be 160 MW or 100 MW. o Mr Robinson indicated that more work needs to be done on what counts to contributing to the flexible capacity product and Ms Guzeleva indicated that an incentive is needed to avoid facilities with a high mingen. • Ms White asked how it will be determined that a facility is flexible – would ESS accreditation be required or would fast ramping capability be sufficient, such as for a curtailed renewable facility. o Ms Guzeleva indicated that we are only looking at ramping capability, you would not need to be accredited for any particular ESS at the time of your RCM certification. Mr Robinson indicated that the criteria for qualification as flexible capacity and for ESS accreditation may be similar or the same, but the two would not be linked. o Mr Robinson indicated that the initial position was that curtailed renewables would not be able to participate, but feedback from the MAC was that curtailed renewables are the first facilities that you want to provide a flexible service. Mr Robinson indicated that such participation would be limited by the level of certainty that there is availability of such facilities, and Ms Guzeleva indicated that a determination still needs to be made on the obligations on facilities that are accredited for the flexibility product.	
8	**Covering the Duration Gap** Mr Robinson led the discussion on covering the duration gap (slides 17 to 22). • Mr Robinson indicated that the duration gap is currently about 4 hours, it will be 8 hours by the mid-2030s, and likely 16 hours by 2050. • Mr Robinson indicated that the proposal is: o for three capability Classes: 1. unrestricted firm capacity;	

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	2. restricted firm capacity; 3. non-firm capacity (intermittent generators); o availability obligations will be placed on Classes 1 and 2, but not Class 3; o intermittent facilities would be allocated significantly lower CRCs (to be discussed on 21 July 2022); and o when there is a capacity shortfall and we are choosing between proposed facilities, facilities in Class 1 will be preferred over Class 2, and Class 2 over Class 3. • Mr Robinson provided a graphical explanation of the duration gap. • Mr Robinson indicated that the RCM needs to provide a signal on the length of the duration gap and an incentive to address it. • Mr Robinson acknowledged advice from some RCMRWG members of the need for investment certainty and the concerns with the idea that the storage availability hours might change for facilities that had been built to particular standards. • Mr Robinson provided a strawman on how to deal with this: o AEMO is to publish an availability duration target in the Electricity Statement of Opportunities (**ESOO**); o The availability duration target is to be the length of time that needs to be filled, on top of the Class 1 facilities, based on: ▪ the forecast 10% POE load shape (consistent with the peak that we are planning for); ▪ existing and committed Class 1 capacity is fully available; ▪ existing and committed Class 2 facilities are available per some 'transitional arrangements'; and ▪ existing and committed Class 3 facilities' output is as per their CRC. This will allow AEMO to work out a duration that needs to be covered by new facilities and Class 2 facilities will be assessed for CRC based on this availability duration. The 'transitional arrangements' for Class 2 facilities will be that the facility will be assessed: ▪ for 5 years after commissioning, based on the availability duration at the time the facility was built; and ▪ then based on the availability duration at the time. • In response to a question from Mr Peak, Mr Robinson indicated that there will still be a single reserve capacity target and that Capability Classes will work in a similar way to how availability Classes currently work. • Ms Bedola asked if gas facilities will be allowed to opt for a lower duration availability – such as 8 hours instead of 14 hours.	

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	o Ms Guzeleva indicated that this is correct but that we need to be careful in the short- to medium-term to avoid a situation like in the eastern states, where a facility can opt out for a period and there is insufficient capacity to cover the peak. o Mr Robinson indicated that this is one way to deal with fuel duration so the facility owner can choose to have less fuel storage or shorter daily gas supply, but then it will get fewer Capacity Credits. • In response to a question from Ms White, Ms Guzeleva indicated that these arrangements will affect the electricity storage obligation intervals (**ESROI**). Mr Robinson indicated that batteries built further in the future would have longer durations. • Mr Schubert suggested that we will not need all storage to be available for the extended duration unless the peak duration is virtually flat. • Ms White asked if AEMO will set the ESROI on a more granular basis (e.g. at an Availability Class or facility level) and for facilities that enter based on four hours will have that 4 hour period grandfathered. Ms Guzeleva indicated that this is correct and that the grandfathering would be for a 5-year period. • Mr Stevens suggested that metrics around solar irradiance gaps in terms of MW hours will be interesting, if not absolutely critical, even in the near future. This should be a key metric for the ESOO and, if the modelling is robust, will be enlightening in relation how realistic it will be to procure sufficient energy storage. • Mr Shahnazari suggested that the question is whether we pass the investment risk to consumers by setting the ESROI at, for example, 4-5 hours for the batteries that are currently entering the market, or should we leave it open, for example, by applying the Effective Load Carrying Capability (**ELCC**) method to battery storage to signal to the market that the capacity value will change as system stress events happen for longer periods. o Mr Robinson agreed that ELCC would account for the effect of different types of events on batteries, but we will need a way to account for duration if ELCC is only used for intermittent facilities. • Ms Ng asked for clarification that the 14-hour fuel requirement is the requirement for Class 1 facilities. o Mr Robinson indicated that Class 1 facilities will need to demonstrate that they can be available all of the time but there may be different ways to demonstrate this – maybe the 14 hour fuel requirement should be retained. o Ms Guzeleva indicated that a decision has not been made on whether a facility's availability duration impacts its Capacity	

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	Credits, or somehow links to the capacity price – further discussion is required. • Ms White asked if 5-year grandfathering for batteries is long enough. Ms Guzeleva indicated that batteries have a life of about 3,500 cycles, which is 10 years at 1 cycle/day, so a 5-year grandfathering period was selected to provide for more than one cycle per day. • Ms White asked if 'existing or committed' Class 2 facilities means facilities that are already developed and committed, or others that are committed in the medium term before the longer duration is needed. o Mr Robinson indicated that the intent is that this will apply to batteries that are committed at the time that the ESOO is done. As an example, Ms Guzeleva indicated that, if you commit to a battery with an 8-hour duration, you will continue to get the arrangements for an 8-hour duration for 5 years from the commissioning date. o Ms Bedola asked for confirmation that it is 5-years grandfathering period from commissioning, but the hours are locked in 2 years prior, at ESOO, when you apply for CRC. Ms Guzeleva indicated that the AEMO makes the projection 3 years in advance, but that the 5-year grandfathering period commences after the facility is commissioned. • Mr Peak suggested that, if batteries are to be written down over 5 years, then they will have a very high effective capital cost. o Mr Robinson suggested that this would be an extreme approach – it would not be correct to assume that a battery would get no Capacity Credits after the 5-year period. Ms Guzeleva suggested that, in considering the length of the grandfathering period, there is a tradeoff between benefits to facility owners vs shifting risk to customers. o Mr Peak noted that, if a battery can last 3,500 cycles, and this will be done in 5 years, then the battery will require a much higher rate of return to cover the capital costs. o Mr Robinson indicated that different facilities have different investment models and we need to strike a balance that provides enough investment certainty to make facilities bankable but also leaves enough flexibility so that consumers only pay for what they need. The arrangements need to be technology neutral. o Ms Bedola agreed with Mr Peak and asked if the BRCP should allow capex to be recovered over 5 years. Ms Guzeleva indicated that the guarantee is for a 5-year fixed price and that facilities can continue to get Capacity Credits and be paid after that for as long as they can operate.	

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	o Ms White indicated that she understands why this is being proposed from a policy perspective but that investment certainty needs more consideration, and that this arrangement would make batteries only attractive to the likes of Synergy. o Ms Guzeleva clarified that batteries would get a guaranteed capacity price for 5 years and then would get the market prices for as long as the battery can perform at the level it is committed to. o Mr Higgins noted that this is similar to the current fixed price arrangements where facilities can opt for a 5-year fixed price that reverts to a floating price after 5 years. Ms Guzeleva agreed and indicated that the rules for batteries may be drafted so the facility owner can choose a 5-years fixed priced or select a floating price. o Ms White sought clarity that a battery with a 4 hour interval could continue with a 4 hour interval after the 5 year price arrangement, but its price could be lower if the Class requires an 8 hour interval, not that the 4 hour battery would be required to be available for 8 hours. Mr Robinson indicated that the initial position is that CRC would be assessed on the basis of 8 hour availability. o Ms Guzeleva indicated that EPWA would appreciate feedback on whether 5-years is sufficient, but any views need to provide facts about what different technologies can provide, because the RCM is not just about revenue certainty, it is also about providing incentives for market entry for facilities that can meet consumers' needs. o Mr Peak indicated that there is a real conflict between the consumers wanting reliability and lower prices, and that they cannot have both. ▪ Mr Robinson noted that there should be an efficient tradeoff between the reliability and price. ▪ Ms Guzeleva agreed that generators need certainty for a period, but that consumer should not be paying for a long period for something that actually does not provide the needed benefits – we need the right balance. • Mr Stevens suggested that the 14-hour fuel requirement needs to be revisited because we do not have a 14-hour peak – instead we have 2 peaks, roughly 5:00 to 9:00 am and 5:00 to 8:00 pm, and this should from the basis of the fuel requirements for Classes 1 and 2. This may be a semi-dynamic calculation, particularly for Class 2, because things like EVs will change the peak demand profiles. o Ms Guzeleva agreed that the rules need to set the principles for AEMO to determine the duration rather than specify the	

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	duration, and that AEMO should make the determination in year 1 of each capacity cycle. • Ms Bedola suggested that it sounds like the ESROI decision assumes a 5 year life but the BRCP assumes longer life. When a battery becomes the marginal unit for capacity, the BRCP should be based on a reasonable expectation of the life of the batteries, so 5 years for capex recovery. o Mr Robinson agreed that, when a battery becomes the marginal unit, the BRCP should be based on reasonable expectation of its life. However, the ESROI and the capital recovery period for the BRCP do not have to be the same. For example, it would not be in consumers' interest to guarantee a return on investment for a 15 year facility, but such a facility can opt for a 5-year fixed price arrangement, after which it returns to the floating price – the facility owner makes a commercial investment decision based on these settings. o Mr Shahnazari indicated that, alternatively, the ELCC method could be used for batteries. • Mr Stevens indicated that he does not agree that the determination of capacity prices must factor in investment uncertainty and changes in technology costs. o Ms Guzeleva indicated that we have to be technology neutral and assume that technology will respond to the incentives provided, and the RCMRWG's job is to come up with the right incentives. • Mr Schubert indicated that the party that is best able to manage the risk should bear the risk to ensure efficient outcomes. o Mr Peak suggested that investors have no method to manage their risk where the market is dominated by a Government-owned entity and the Government has interventionist policies. Investors need sufficient protection. o Ms Guzeleva indicated that investors have to take some risk. o Mr Peak pointed out that the Government has made numerous changes to the RCM over the years – taking out the transmission deep costs, then going to the capacity versus excess capacity price, then the Lantau curve – but we have not seen any investment driven by the RCM over the last 10 years. Now we are going into an environment where we want to bring in a lot of storage and wind, so we need an investment environment to bring those on. o Ms Guzeleva pointed out that the problem is that we have had over capacity for a very long time and that capacity prices should go up when capacity is retired over the coming years. o Mr Stevens agreed that capacity efficiency is an objective for the RCM, but not allowing abnormal rents.	

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	o Ms White agreed that there is risk involved in investment, but WA is relatively risky market in the sense that the policy and the WEM Rules can change rapidly, while investment is lumpy and has a much longer duration. The RCM was designed to provide investment certainty, amongst other things. o Ms Guzeleva indicated that the RCM was not intended to provide investment certainty, but to ensure reliability, and that is done by making sure that investments can recover their costs while keeping energy prices efficient.	
9	**Next Steps** Mr Robinson indicated that there is another RCMRWG meeting on 21 July 2022 to discuss alternative methods to Effective Load Carrying Capability to assign CRC. A consultation paper will then be published for comment. Mrs Papps asked what resolutions from the RCMRWG meeting would be brought to the MAC. Ms Guzeleva indicated that the proposal would be outlined in the consultation papers which will be circulated to the MAC.	
10	**General Business** No general business was discussed.	

The meeting closed at 11:30am.

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	21 July 2022
Time:	12:45 pm – 2:30 pm
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Rhiannon Bedola	Synergy	
Oscar Carlberg	Alinta Energy	Subject matter expert
Manus Higgins	AEMO	until 2:00pm
Jacinda Papps	Alinta Energy	
Brad Huppatz	Synergy	Subject matter expert
Peter Huxtable	Water Corporation	
Sam Lei	Alinta Energy	Subject matter expert
Dimitri Lorenzo	Bluewaters Power	Proxy for Paul Aires From 1:20pm
Mark McKinnon	Western Power	
Patrick Peake	Perth Energy	
Matt Shahnazari	Economic Regulation Authority	From 1:15pm
Peter Shardlow	Analytics Data Science (for Collgar Wind Farm)	Subject matter expert
Noel Schubert	Small-Use Consumer representative	
Rebecca White	Collgar Wind Farm	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	
Shelley Worthington	EPWA	

Apologies	From	Comment
Dev Tayal	Tesla Energy	
Andrew Walker	South32 (Worsley Alumina)	

Apologies	From	Comment
Dale Waterson	Merredin Energy	
Andrew Stevens	Consultant	

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1 **Welcome**

The Chair opened the meeting at 12:45pm.

2 **Meeting Apologies/Attendance**

The Chair noted the attendance as listed above.

3 **Alinta's Presentation on an alternative for Certified Reserve Capacity (CRC) Allocation for Intermittent Generators**

Mr Carlberg presented Alinta's concerns with the current RLM and the Effective Load Carrying Capability (ELCC) Delta method. The following points were discussed:

- In regards to the example on slide 9, that assesses the impact of an additional 1,000 MW windfarm at the location of the Yandin Wind Farm on the CRC allocation to existing wind farms under the delta method, the following was discussed:
    - Mr Robinson noted that 1,000 WM is a big increase of wind energy nameplate capacity in the SWIS and that such a big new entrant changing the CRC of incumbent wind farms by around 15% was not necessarily a sign that the method produces volatile outcomes.
    - In response to a question from Mrs Bedola, Ms Koziol noted that the Rule Change Panel had modelled a similar scenario for the assessment of RC_2019_03 and that in this scenario the entrance of the new wind farm had increased the total CRC of the fleet but also reduced the CRC of some of the existing Facilities.
- Mr Carlberg summarised Alinta's proposed method for assigning CRC to intermittent generators as follows:
    - assign CRC based on the average output during the expected times of system stress on the basis of historic peak demand days adjusted for variance as per the current Relevant Level Method, but removing the current k and u factors;
    - determine the times of expected future system stress as the day time with the highest likelihood of unserved energy, based on RBP's system stress modelling - this would be the Trading Intervals from 4:00 pm to 9:00 pm; and
    - use the 20 days with the highest system demand for each year of a five-year reference period as the historic peak demand days.

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- The Chair noted that the 20 days with the highest system demand of every year in the reference period are unlikely to be an adequate representation of system stress. Mr Carlberg clarified that the 95th percentile was chosen to ensure a big enough sample size but that the choice was arbitrary and that Alinta Energy is open to other suggestions.
  - o Mr Schubert noted that 20 days are many more days then the annual peak/extreme weather days.
  - o The Chair questioned the appropriateness of selecting the same number of days form each year for the peak demand days, noting that the presented analysis showed that, in some years, system demand does not reach a level resulting in system stress. The Chair suggested that choosing the days with the highest system demand in the whole reference period may be more appropriate.
  - o Mr Carlberg noted that Alinta Energy considered that the conditions of past system stress event might not represent future system stress events. Mr Carlberg repeated that Alinta Energy is open to other ways for selecting the peak demand days.
- In response to a question form the Chair, Mr Carlberg considered that it would make sense to align the expected future system stress with the Electric Storage Resources Obligation Intervals (**ESROI**). Mr Carlberg considered that the times for expected future system stress could be adjusted but may need to include a transitional mechanism for any changes.
- Mr Eliot noted that, as part of the discussion on RC_2019_03, AEMO had raised concerned about having too many wind farms in a single location such as the North Country, and that one of the reasons the Rule Change Panel proposed the delta method was that the method provides a clear locational signal. Mr Eliot asked how Alinta's proposal addresses this concern.
  - o Mr Carlberg indicated that Alinta's proposed method does not account for the correlation of generation from wind farms in the same region. Mr Carlberg noted that Alinta's proposed method focusses on picking intervals expected to be system stress intervals in the future. Mr Carlberg considered that accounting for the correlation of generation of wind farms, in particular over a small amount of intervals, may lead to arbitrary results.
  - o Mr Eliot considered that locating all wind farms in the same region could expose the system to potential black outs.
  - o Mr Carlberg considered that it is not a problem to locate all wind farms in the same region as long as the weather conditions in that region allow them to be available during the future system stress events.

Item	Subject	Action
	o Mr Schubert considered that the weather conditions that result in system peak often exhibits low wind in the North Country. Therefore, locating all the wind farms in the North Country is an issue for system peak. o Mr Lei considered that such peak days would be accounted for in the proposed method. • In response to a question from Mrs Bedola, the Chair clarified that a method based on historic output needs to include adjustments to account for reduced output due to network constraints. • Mr Eliot noted that setting the CRC for intermittent generators based on their average output during system peak intervals implies that it is acceptable that the capacity will not be available during half of the peak intervals. • Mr Carlberg clarified that the proposal was to use the average output adjusted for variance and that this was based on the current RLM. Mr Carlberg considered the method of weighing the performance in the peak intervals should be based on the desired certainty for the capacity to be available at peak, but that any further discounts below the average output is arbitrary. • Mr Peake suggested that it should be assessed how the proposed method affects system reliability.	
4	**Collgar's Presentation on alternative for CRC Allocation for Intermittent Generators** Ms White presented Collgar's concerns about the delta method, and introduced Collgar's suggested alternative and associated modelling scenarios and outcomes. The following points were discussed: • Ms White summarised Collgar's proposed method for assigning CRC to intermittent generators as follows: o use seven years of historic demand adjusted for distributed PV; o determine the Effective Load Carrying Capability (**ELCC**) for the fleet of intermittent generators as the average of the ELCCs of seven individual years; and o Allocate the fleet ELCC to individual facilities based on relative average performance during defined peak Trading Intervals in each year (the 4 Trading intervals with the highest system demand from the 12 days with the highest demand) of the reference period. • In response to a question form the Chair, Mr Shardlow clarified that the results of the future scenarios on slide 7 are based on the announced retirements of Synergy's coal fired power plants and assumptions on new intermittent generators entering the market. Ms White clarified that the underlying fleet of intermittent generators differs in the different years, based on Collgar's assumptions about	

Item	Subject	Action
	new facilities entering the market, but is the same for any year across the different methods assessed. • Ms White noted that changing the method for allocating the fleet ELCC to individual facilities, as proposed by Collgar, will reduce the valuing of the correlation between different facilities. Ms White considered that this is a trade-off for reducing the volatility of the CRC allocations. Ms White suggested that an alternative approach is to assign fleet ELCC values for groups of facilities in different regions. • In response to a question from Ms Koziol, Ms White clarified that, for the scenario where facilities are grouped by region, Collgar Wind Farm is the only Facility in the east region.	
5	**Next Steps** Mr Robinson noted that further analysis will be undertaken to assess different options to assign CRC to intermittent generators. The Chair reiterated that any method must focus on performance during system stress events and must provide confidence that intermittent generators will perform during times of system stress at the level of the CRC assigned. Mr Robinson noted that the effect of the proposed methods on system reliability will be assessed.	
5	**General Discussion** Mrs Bedola noted that neither the Network Access Quantity regime nor the allocation methods proposed provide adequate locational signals to deter a new facility from locating close to an existing one and reducing the value of the existing facility. The Chair noted that the method must not remove a signal for intermittent generators to firm up their capacity. Several members agreed.	

The meeting closed at 11:30am.

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

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

Market Advisory Committee (**MAC**) Meeting 2022_08_23

1. Purpose

- The Chair of the Cost Allocation Review Working Group (**CARWG**) is to update the MAC on the activities of the CARWG since the last MAC meeting.
    - o The MAC is requested to note this progress update.

2. Recommendation

That the MAC note that Energy Policy WA (**EPWA**) and its consultants (Marsden Jacob) have undertaken the following analysis as part of the assessment of options for the cost allocation methods:

(1) Modelling of Market Fees on the basis of the following options:

(a) Current practice in the Wholesale Electricity Market (**WEM**) based on metered energy for generators and non-scheduled loads.

(b) Current practice in the National Energy Market (**NEM**), applied to the WEM. This includes the use of the following allocations:

- o for generators: 50% charged on capacity (MW) and 50% on metered energy (MWh); and
- o for market customers: 50% based on metered energy and 50% based on number of connections.

(c) WEM Hybrid Option. This includes the use of the following allocations for Market Generators and Market Customers:

- o for generators: 50% charged on capacity (MW) and 50% on metered energy; and
- o for market customers: 50% based on metered energy and 50% based on the Individual Reserve Capacity Requirement (**IRCR**).

(2) Allocating Frequency Regulation costs to WEM generators and loads on the basis of NEM 'causer pays' contribution factors to determine the impact on scheduled, semi-scheduled generators and loads.

(3) Developing a 'Tolerance Methodology' for allocating Frequency Regulation costs and quantifying the impacts of the methodology on both generators and loads, in comparison to the current cost allocation method and the causer pays method under item (2).[1]

[1] AEMO suggested that the CARWG consider the Tolerance Methodology to allocate Frequency Regulation costs, AEMO sent an explanation of the methodology to EPWA on 3 June 2022 and EPWA forwarded to the methodology to the CARWG for consideration on the same day. Marsden Jacobs is currently considering this AEMO's suggested approach.

(4) Developing amendments for certain types of Facilities in the WEM to ensure that the application of the Runway Method[2] for allocating Contingency Reserve Raise costs remains consistent with causer pays principles.

3. Next Steps

- Findings from the above assessments are to be presented and discussed with the CARWG on 30 August 2022.
- The findings will then be presented to the MAC at its 11 October 2022 meeting.
- A draft consultation paper for the Cost Allocation Review is to be tabled for discussion at the MAC meeting on 15 November 2022.

[2] The 'Runway Method' is currently used to allocate Spinning Reserve costs, as specified in Appendix 2 of the WEM Rules. From the New WEM Commencement Day (1 October 2023), the Runway Method will be used to allocate Contingency Reserve Raise costs and Rate of Change of Frequency (RoCoF) Control costs, as will be specified in Appendix 2A of the WEM Rules (see the companion version of the WEM Rules at https://www.wa.gov.au/system/files/2022-02/WEM-Rules-Companion-Version-Prepared-as-at-1-February-2022.pdf).

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

Agenda Item 7(a): Overview of Rule Change Proposals (as of 11 August 2022)

Market Advisory Committee (**MAC**) Meeting 2022_08_23

- 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	31/12/2022
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	31/12/2022
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Publication of Draft Rule Change Report	31/12/2022

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	31/12/2022
Standard Rule Change Proposals with the First Submission Period Open						

Pre-Rule Change Proposals

Reference	Proponent	Description	Next Step	Date
RC_2020_04	Rule Change Panel	Balancing Facility Loss Factor Adjustment	Consult with the MAC on the priority for development of a Rule Change Proposal	TBD

Rule Changes Made by the Minister and Awaiting Commencement

Gazette	Date	Title	Commencement
2022/67	17/05/2022	Wholesale Electricity Market Amendment (Network Access Quantities Procedure) Rules 2022	• Schedule A will commence on 01/09/2022 • Schedule B will commence on 01/03/2023 o Amending Rules can be found at Wholesale-Electricity-Market-Amendment-Network-Access-Quantities-Procedure-Rules-2022.pdf (www.wa.gov.au)
2021/212	17/12/2021	Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021	• Schedule F will commence on 01/09/2022. • Schedule G will commence on 01/01/2023. • 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: o The Amending Rules specified in Part 4 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 01/09/2022.

Gazette	Date	Title	Commencement
			o The Amending Rules specified in Part 4 of the commencement notice published on 17/12/2021 in Gazette 2021/212 will commence on 01/09/2022. o The Amending Rules specified in Part 5 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 06/12/2022.

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

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

Market Advisory Committee (**MAC**) Meeting 2022_08_23

1. Purpose

The MAC is asked to:

- review the draft Reserve Capacity Mechanism Review Consultation Paper (**Attachment 1**);
- note that consultation paper is in a draft state and that Energy Policy WA is still working on the wording in the paper; and
- provide guidance to the Coordinator on the conceptual design proposals and questions outlined in the draft consultation paper.

2. Recommendation

That the MAC:

(1) provides guidance to the Coordinator on the conceptual design proposals in the draft consultation paper, noting that the paper is in draft form.

3. Process

The Coordinator of Energy, in consultation with the MAC, is reviewing the Reserve Capacity Mechanism (**RCM**) of the Wholesale Electricity Market (**WEM**) in Western Australia 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 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 review is being conducted in three stages:

- Stage one focussed on the definition of reliability and the characteristics of the capacity needed in future years, including the Planning Criterion, the methods for assigning Certified Reserve Capacity (**CRC**)[1] and the Benchmark Reserve Capacity Price (**BRCP**).
- Stage two will assess 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 (**IRCR**).
- Stage three will deliver the detailed design and any transitional arrangements.

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

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

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

The conceptual design proposals and related questions are specified in the text boxes throughout the report.

A table is provided on the following pages for the information of the MAC that lists the conceptual design proposals in each chapter of the paper and provides a high-level summary of the rationale for each proposal.

Attachments

(1) draft Reserve Capacity Mechanism Review Consultation Paper

Chapter	Design Proposal	Rationale
1 Exec Sum		
2 Introduction		
3 Purpose of the RCM	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.
	2 The RCM will not include a specific product to manage minimum demand. The RCM design and the capacity certification process will seek to avoid incentives for new facilities 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.
	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.	The increasing prevalence of intermittent generation has highlighted the need for flexible capacity to maintain reliability. Therefore, an additional flexibility capacity product is being proposed to provide incentives for capacity that is capable of rapid start and stop, and fast ramping up or down.
	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.	Volatility in operational load and intermittent generation output over shorter timeframes can continue to be managed through the ESS market.

Chapter	Design Proposal	Rationale
4 Review of the Planning Criterion	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.
	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.
	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.

Chapter	Design Proposal	Rationale
	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.
5 Benchmark Reserve Capacity Price	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.	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.

Chapter	Design Proposal	Rationale
	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.	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.

Chapter	Design Proposal	Rationale
	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.

Chapter	Design Proposal	Rationale
	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
6 Valuing Capability when Certifying Capacity	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>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.</td><td>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.</td></tr>
</table>

Chapter	Design Proposal	Rationale
	15 CRC allocation will remain on an ICAP basis, with refunds payable for any forced outage. • The reserve margin in the first limb of the Planning Criterion will be set at the greater of the fleet-wide EFORd and the largest contingency expected at system peak, with AEMO assessing both each year 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.
	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.

Chapter	Design Proposal	Rationale
	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.	• 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.

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

Reserve Capacity Mechanism Review

Consultation Paper

29 August 2022

Working together for a brighter energy future.

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

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Glossary

Term	Definition
Marginal ELCC	The incremental capacity value of a resource measured relative to an existing portfolio – individual resources or resources of same type (e.g. wind class, solar class) are attributed an ELCC based on their marginal contribution to resource adequacy
Portfolio ELCC	The combined capacity contribution of a combination of intermittent and energy-limited resources. This method inherently captures all interactive effects (e.g. wind + battery, solar + battery)
Peak capacity	The basic capacity product in the WEM RCM, which provides MW of availability to meet the first two limbs of the Planning Criterion: system peak and expected unserved energy.
Flexible capacity	A new capacity product, which provides MW of availability which can ramp quickly and reliably to meet a new limb of the Planning Criterion: maximum system ramp.
Planning Criterion	The reliability standard for the WEM, which sets out the factors that AEMO must account for when setting the reserve capacity targets for peak capacity and flexible capacity.

Abbreviations

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

Executive Summary

Note: This is a draft paper, all section 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 of the WEM Rules. The RCM Review also incorporates the Coordinator's first review of the Planning Criterion.

1.1 Background

1.1.1 The Performance of the RCM

The RCM in the WEM in Western Australia has operated successfully since 2004 by:

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

1.1.2 The Need for 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 1000 MW of coal and gas capacity has or is scheduled to retire by 2030.

The SWIS is now in a transition to a lower emissions energy system because of the decreasing cost of renewable facilities, the Federal Government's Renewable Energy Target, increased penetration of DPV, increasing pressure to reduce greenhouse gas emissions and consumers' demand for 'green' products. At the same time, other generation technologies, such as battery storage, are becoming more viable and new sources of dispatchable capacity, such as Virtual Power Plants, are being trialled for future use. Some of these 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 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 methods for assigning Certified Reserve Capacity (CRC)[2] and the Benchmark Reserve Capacity Price (BRCP).
- Stage two will assess 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 (IRCR).
- Stage three will deliver the detailed design and any transitional arrangements.

The MAC has constituted the RCM Review Working Group (RCMRWG) to support the Coordinator'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. An updated timetable for the review stages is included in Appendix A.

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

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

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

1.2 Purpose of this paper

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

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

This paper is structured as follows:

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

In parallel with this paper, EPWA is publishing a review of international capacity markets conducted by Robinson Bowmaker Paul as part of the RCM Review (link to be inserted upon publication of the final consultation paper).

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

The consultation period closes at 5:00pm WST on Monday 26 September 2022. Late submissions may not be considered.

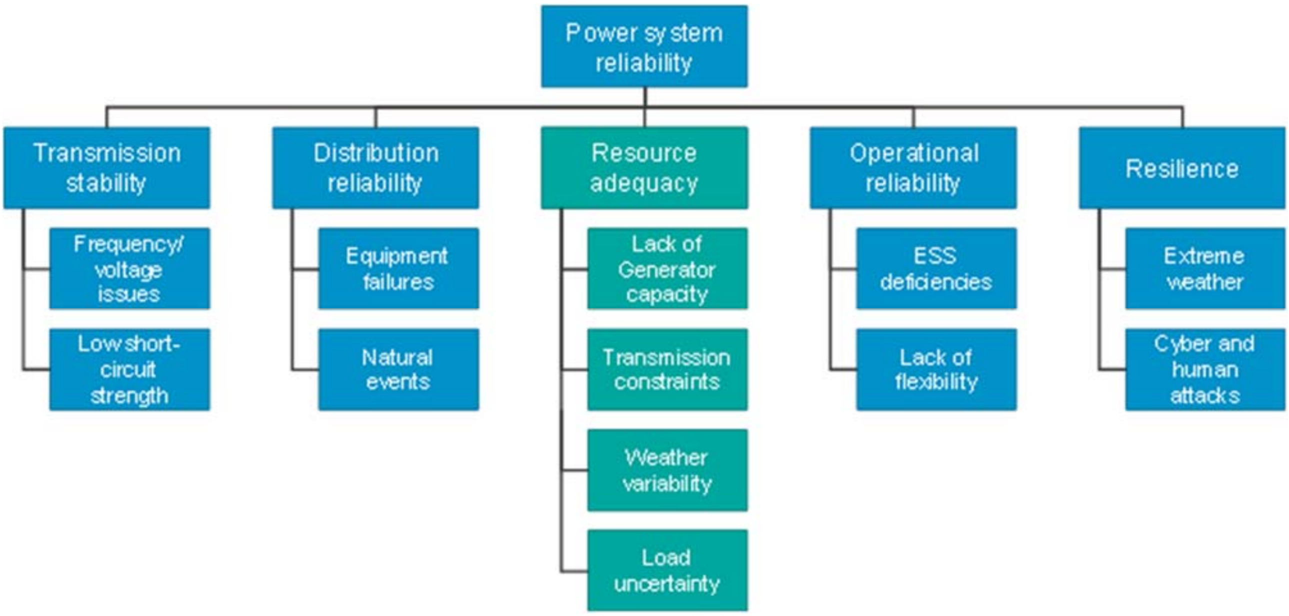
2. How has the Review been conducted

2.1 Resource Adequacy and Operational Reliability

The purpose of the RCM is to ensure that the SWIS has sufficient capacity available to maintain a defined level of reliability at the most efficient cost. The appropriate level of reliability is to be no less than that provided for in the most recent review of the Planning Criterion[4].

Power system reliability is the overall ability of the power system to meet demand for electricity within given standards. Various factors contribute to the level of reliability delivered to customers connected to a particular power system, as shown in Figure 1.[5]

Figure 1: Elements of Power System Reliability



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

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

Capacity mechanisms that consider these elements have historically delivered a generation fleet sufficient to allow the power system operator to schedule and dispatch available capacity to deliver reliable *and* secure[6] electricity supply. The system operator may need to dispatch some facilities in preference to others while ensuring that there is sufficient capability in the fleet to meet the load and provide Essential System Services (ESS).

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4 See section 3.1.4 for analysis of economic efficiency.

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

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

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

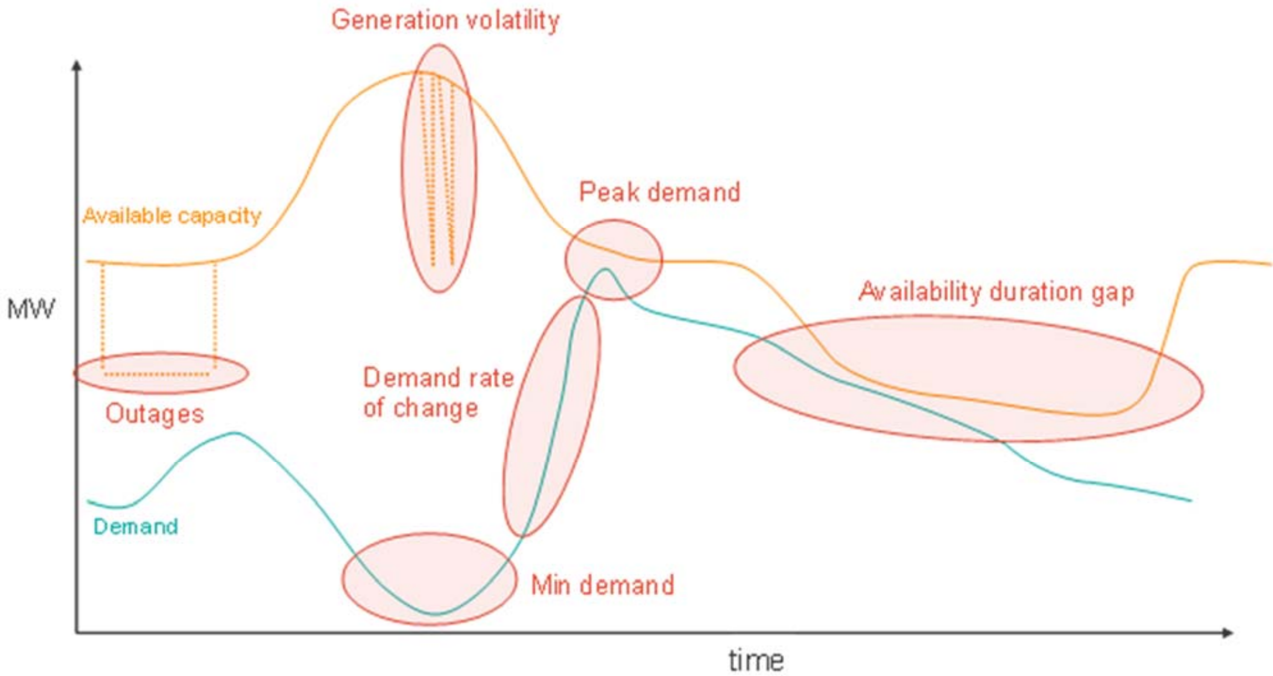
The RCM helps to ensure that, during real time dispatch, a fleet of capacity providers is available to be dispatched to meet demand when needed. Reliability will be affected if there is not sufficient capacity in real time, or if that capacity cannot be operated in a way that meets the requirements at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

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

2.2 How is System Stress changing and what does that mean for the RCM Design

The SWIS faces a variety of challenges, as shown in Figure 2.

Figure 2: Sources of System Stress



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

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

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

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

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

2.2.1 Modelling Approach

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

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

Modelling was conducted to quantify system stress due to:

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

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

Several different fleet development scenarios were considered, to explore potential for different futures, as shown in Table 1.

Table 1: Fleet Scenarios for 2050

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

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

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

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

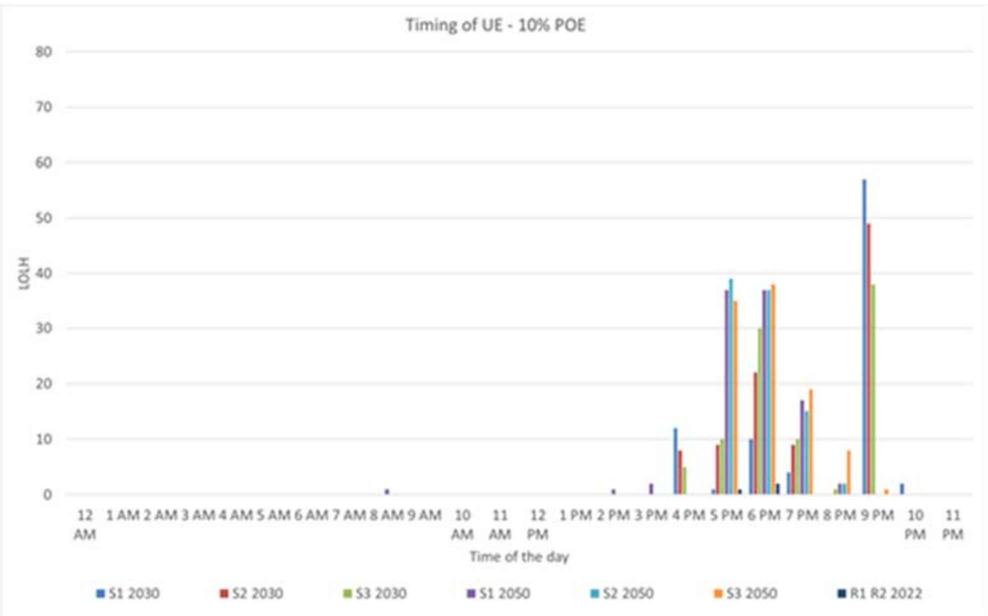
2.2.2 Analysis

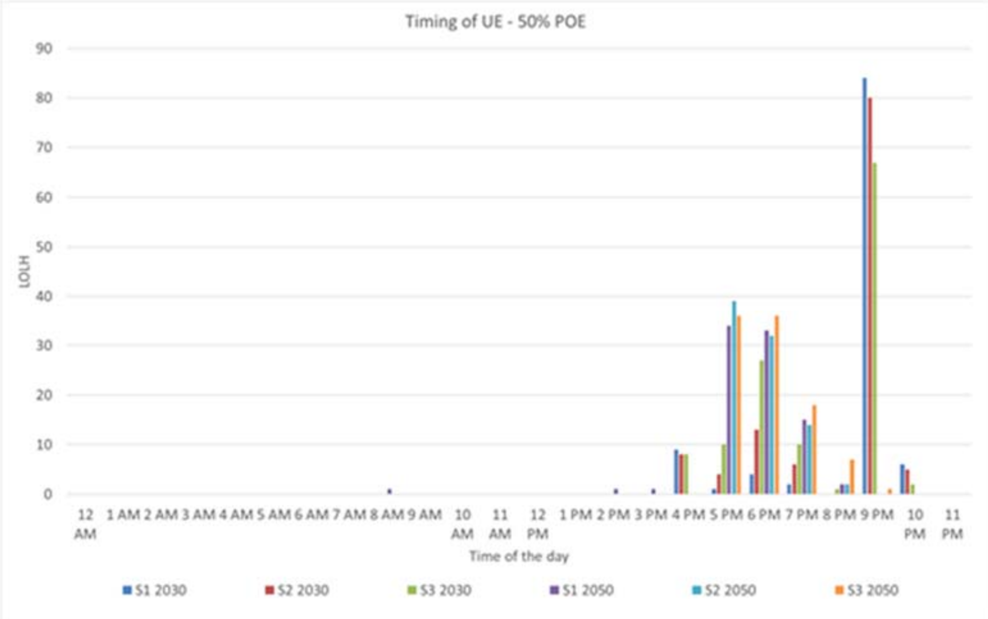
Maximum Demand

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

While there is potential for unserved energy in non-peak periods, the peak period is expected to continue to have the highest likelihood of unserved energy. Figure 3 shows the number of hours of unserved energy at each time of day, highlighting that the evening peak remains the period with highest likelihood of unserved energy, confirming the need for the RCM to continue to provide for this situation.

Figure 3: Timing of Unserved Energy (UE) events (Top: 10% POE, Bottom: 50% POE)

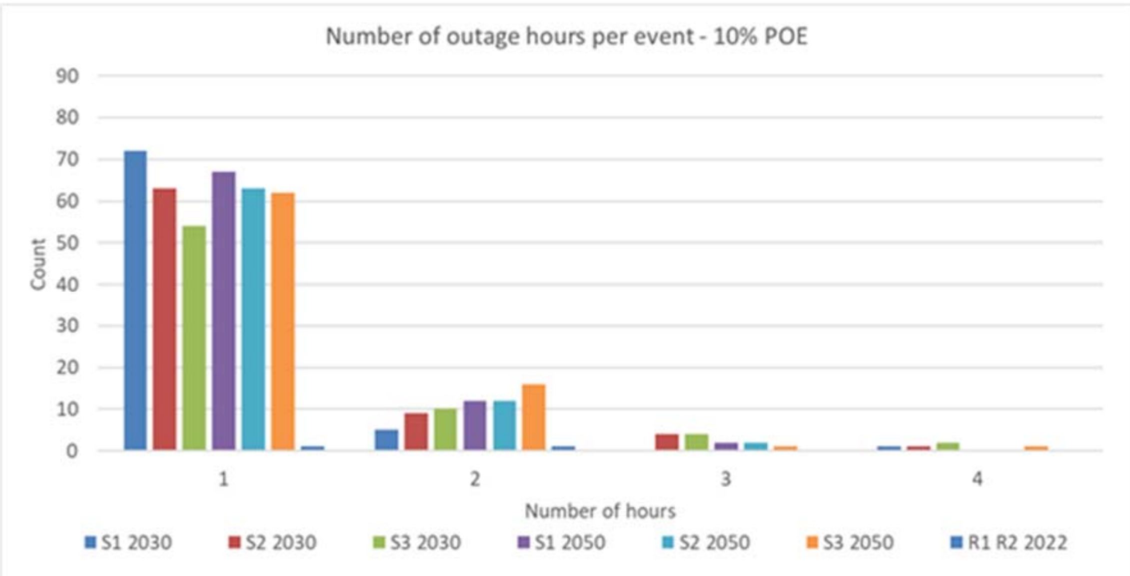


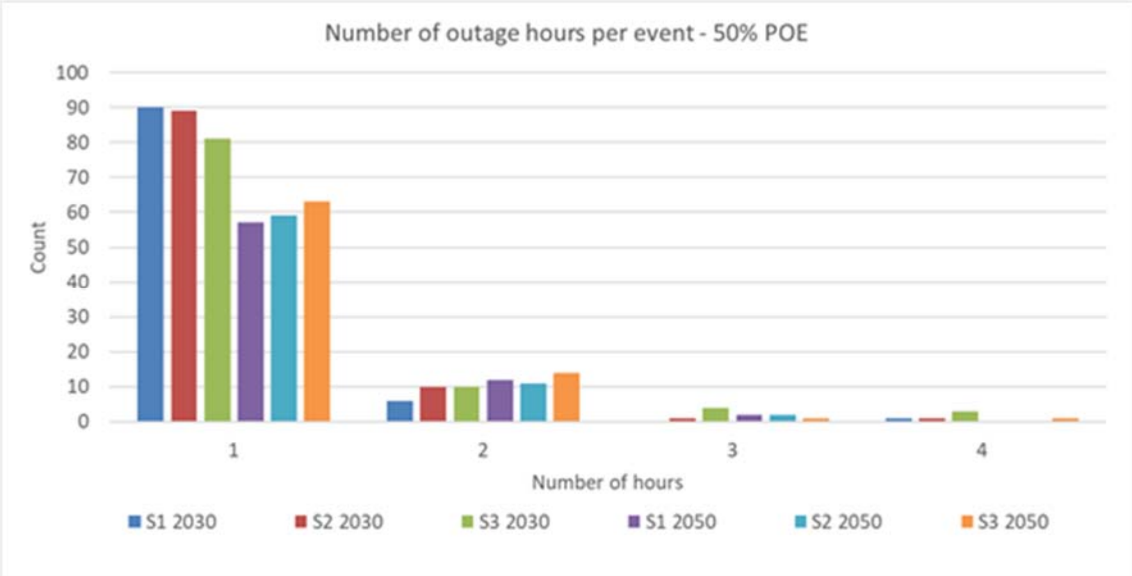


The spike in unserved energy events at 9:00 pm in the 2030 scenarios is due to storage availability hours being set to 4:00 pm to 8:00 pm. Storage availability has been extended to 7:00 am for the 2050 scenarios. Section 5.2 discusses proposals for managing this growing 'duration gap'.

Although facility forced outages can take a long time to fix and restore, the outages suffered by consumers are mostly only one or two hours in duration, but are up to four hours in a few cases, in some scenarios. Figure 4 shows the count of customer outage events lasting one, two, three and four hours.

Figure 4: Number of customer outage hours per event (Top: 10% POE, Bottom: 50% POE)





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

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

Conceptual Design 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 demand.

Consultation Questions:

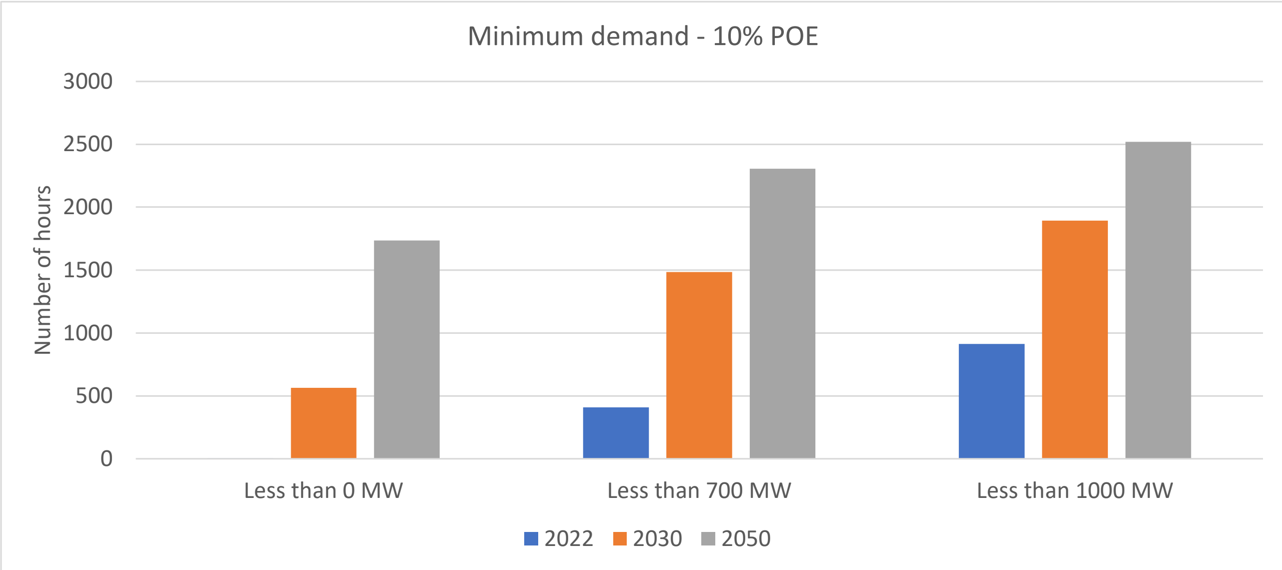
(1) Do stakeholders support the retention of the existing Peak capacity product?

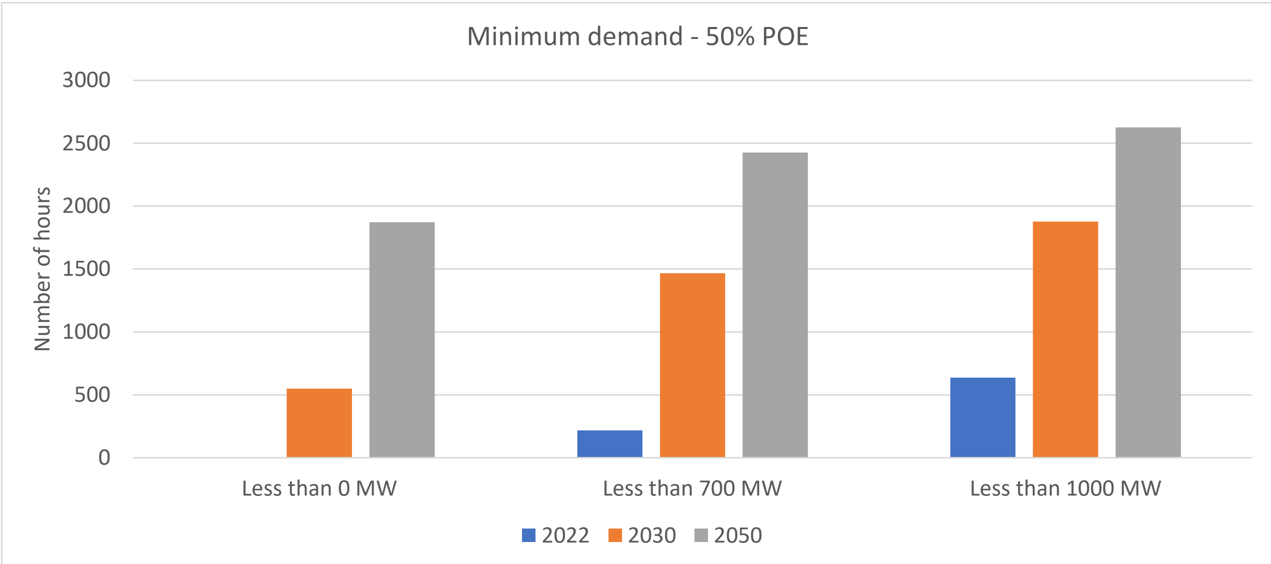
Minimum Demand

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

Operational load will be negative in some intervals by 2030, and will be less than 700 MW for 2400 hours per year (27% of all periods) by 2050, as shown in Figure 5.

Figure 5: Depth of minimum operational load (Top: 10% POE, Bottom: 50% POE)





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

It is considered that:

1. Arrangements for end-user injection management and flexibility are being addressed through the Distributed Energy Resources (DER) Roadmap[7].
2. Facilities capable of helping to manage minimum demand are unlikely to require large capital expenditure with multi-year lead times. Over the coming years, DER Roadmap activities will support the aggregation of small sites into Virtual Power Plants which can be included in

7 https://www.wa.gov.au/government/distributed-energy-resources-roadmap

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

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

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

However, it is important that the RCM does not provide perverse incentives that exacerbate the minimum load risks. It will be particularly important to ensure that new facilities are flexible over a large percentage of their nameplate capacity, avoiding high levels of minimum generation and long start-up times.

Conceptual Design 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.

Consultation Questions:

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

Demand Rate of Change

The modelling indicates that:

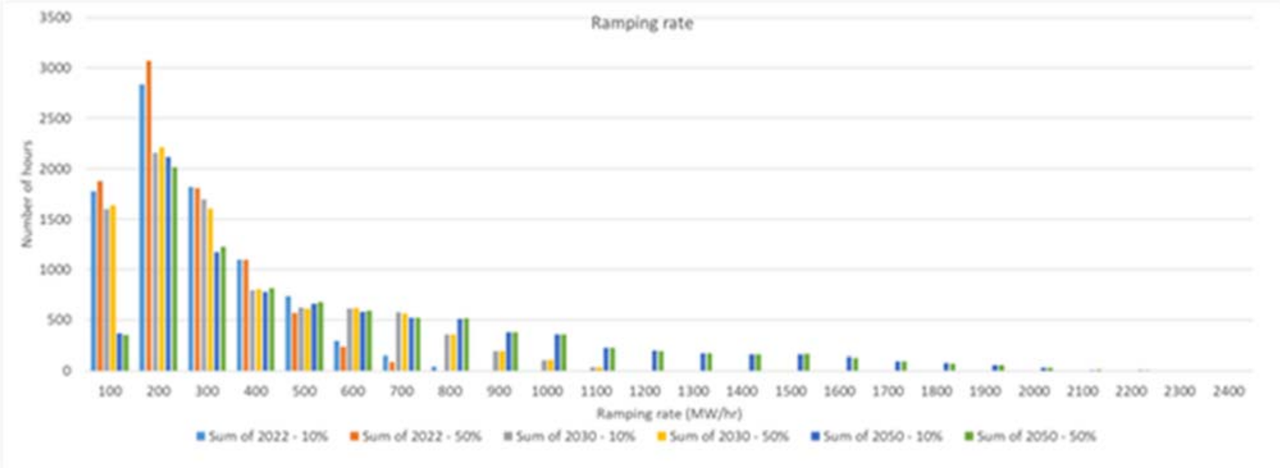
- increasing maximum demand and decreasing minimum demand combine to increase the rate at which operational load changes from the mid-day through to the evening peak; and
- the magnitude of the differential between the low and high points increases over time, as does the overall ramp rate needed from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

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

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

Figure 6 shows the number of hours in each year in which ramp rates are expected to be at a particular level. The highest ramp rate required is around 800 MW per hour in 2022, close to 1100 MW per hour by 2030 and close to 2400 MW per hour by 2050. This means that the WEM will increasingly need very flexible generation that can start quickly, ramp up and down quickly, and stop quickly.

Figure 6: Future Ramp Rates



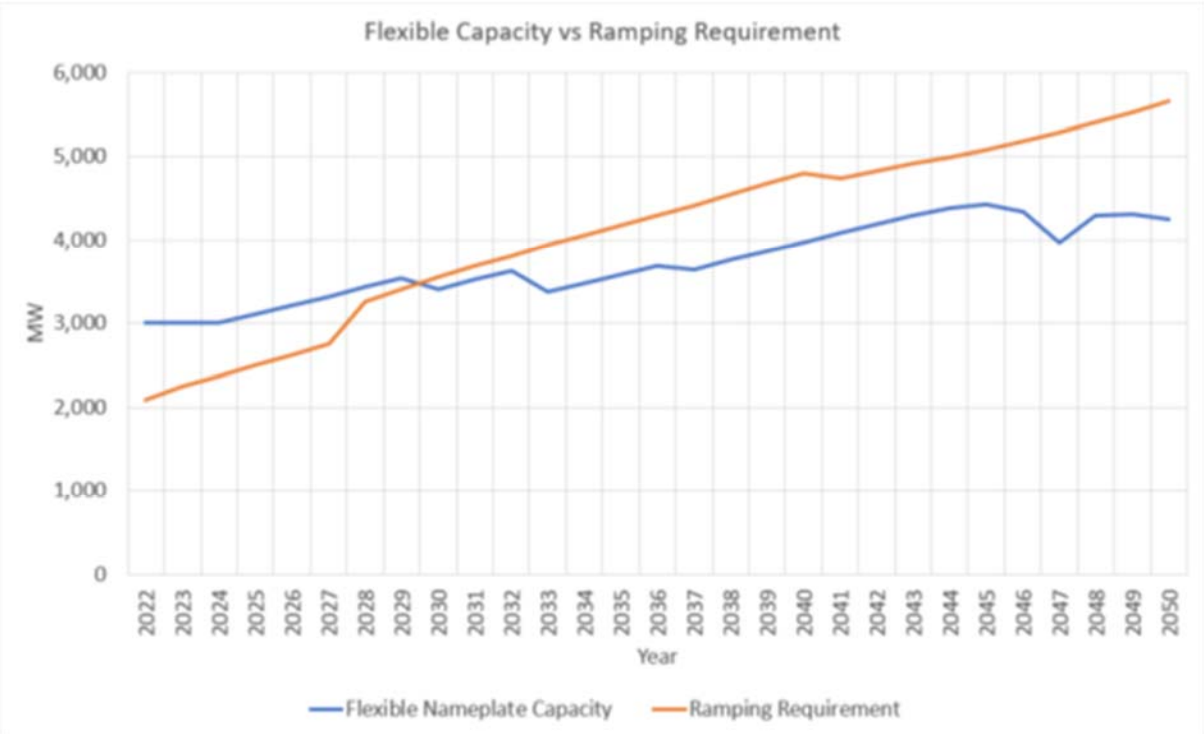
The modelling indicates that the SWIS will see ramp rates from changes to underlying operational demand in excess of 2 GW/hour by 2050. This is well within the capabilities of current technologies (e.g. OCGTs and batteries), as long as sufficient capacity of such technologies is available.

However, an OCGT is unlikely to be an option in a zero carbon future.

Figure 7 compares:

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

Figure 7: Flexible capacity needed for energy shifting vs ramping requirement



From the late 2020s, the fast-ramping capacity required in these fleet development scenarios exceeds the capacity required to shift energy between the middle of the day and the peak.

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

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

Conceptual Design Proposal 3:

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

Consultation Questions:

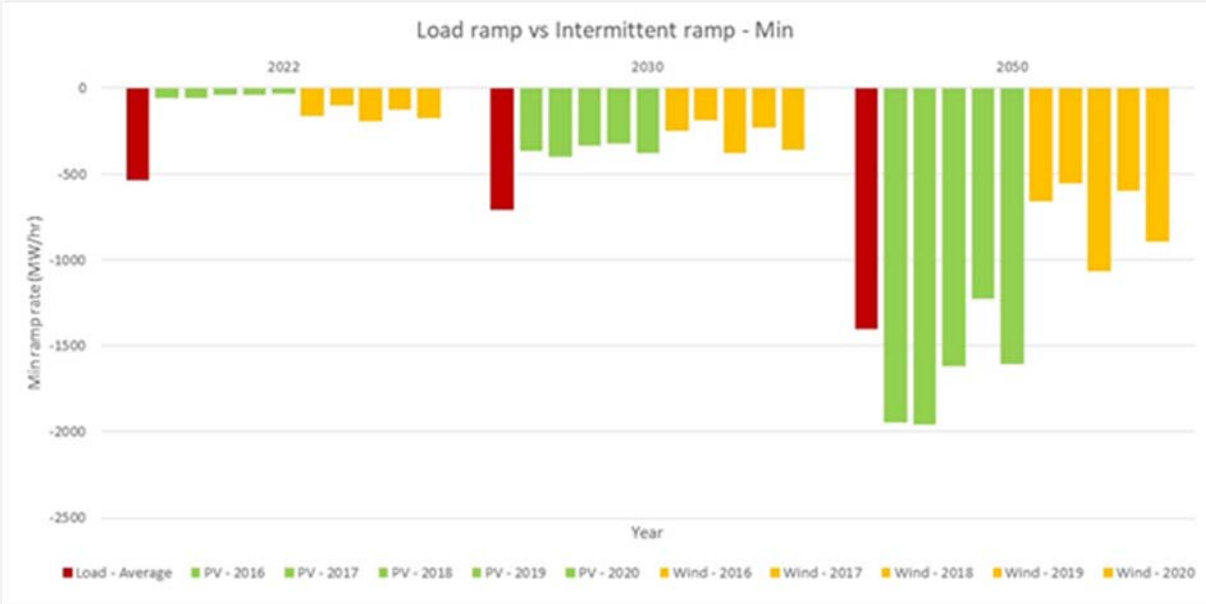
(3) Do stakeholders support inserting a new flexible capacity product in the design of the RCM?

Generation and Demand Volatility

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

Figure 8 shows the maximum expected variability from solar and wind facilities (green and yellow bars), compared to the upward/downward ramp required to meet underlying operational load (red bars) for 2022, 2030 and 2050. The maximum hourly solar and wind ramping estimates are based on the historical generation profiles of intermittent facilities in each year from 2016 to 2020, with the volume scaled up to account for additional installed capacity in 2030 and 2050. The maximum hourly operational load ramp rate is based on the ramping analysis discussed above.

Figure 8: Downward ramp rate comparison



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

If solar generation penetration increases as modelled in 2050, the upward and downward ramp rate from grid connected PV could, at times, be greater than the ramp in underlying demand. However, this maximum solar ramping is not due to underlying variability in solar output, but rather reflects the regular daily profile of solar generation, with these large changes only occurring at sunrise and sunset. EPWA considers that these regular and predictable periods of high ramp rates can be managed through market processes to spread the change over time, and it should not be necessary to build specific capacity to respond over and above the quantity required to manage changes in operational load. That means that the RCM does not need to address this issue directly, because volatility in operational load and intermittent generation output over shorter timeframes can continue to be managed through ESS.

Conceptual Design 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.

Consultation Questions:

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

3. Review of the Planning Criterion

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

3.1 Planning Criterion for System Adequacy

3.1.1 Measures for System Adequacy

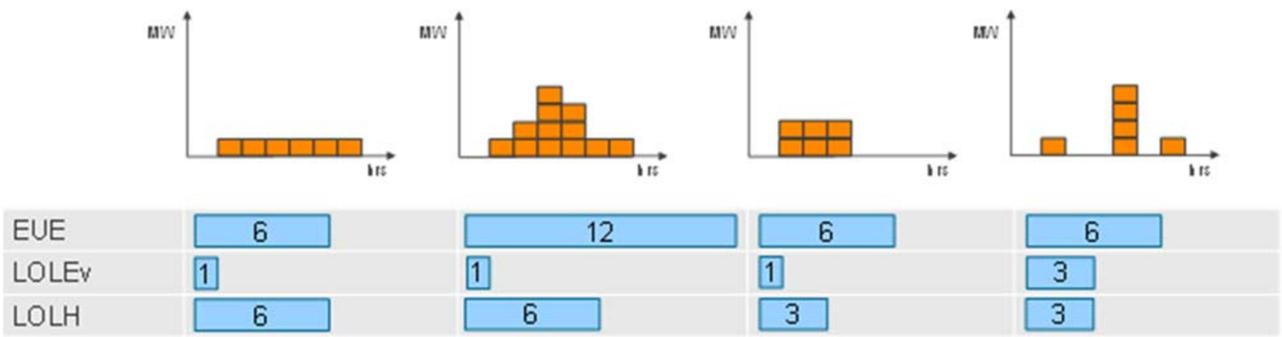
Power system reliability can be measured in several different ways, each describing a different aspect of the impact of disruptions on consumer supply:

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

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

The various metrics can produce very different results for the same events, or the same results for very different events, as shown in Figure 9.[8]

Figure 9: Reliability metrics for different outages



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

The different kinds of shortfall events are best served by different technology configurations. For example, storage resources can assist in all types of events, but more stored energy would be needed to deal with event 1 than event 4, which in turn would require more stored energy than events 2 and 3.

A future proof reliability criterion must account for the metrics which are important for the power system in question.

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

3.1.2 The Current Planning Criterion

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

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

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

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

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

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

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

This two-limbed criterion is unusual internationally, as the Planning Criterion (also known as the reliability criterion) in other markets is set using a single limb, based on the number of LOLEv, the number of LOLH or the expected quantity of EUE.[9]

Other jurisdictions are looking at moving to a multi-limbed criterion like the WEM because future fleet characteristics mean that their contribution to reliability at times other than peak is also important. The recent NEM Reliability Panel draft reliability standard and settings report[10] committed to further work on another limb for the NEM reliability criterion. The review of international capacity mechanisms shows that a single-limb criterion risks missing some aspects of reliability in the future, and it remains appropriate to retain a two limbed Planning Criterion in similar form to the current Planning Criterion.

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

The current limb (a) – the 10% POE peak exceedance measure – also remains appropriate. Using a LOLEv count would be more appropriate if the modelling showed infrequent long and deep outages, but shown in Figure 4, the modelling shows that with the flattening of the peak, potential loss of load events are likely to be short and shallow.

Retaining the two current limbs of planning criterion was supported by the MAC.

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

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

Conceptual Design Proposal 5:

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

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

Consultation Questions:

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

3.1.3 The Reserve Margin in the Planning Criterion

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

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

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

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

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

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

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

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

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

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

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

This proposal was supported by the MAC.

Conceptual Design Proposal 6:

Amend the reserve margin so that:

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

Introduce the proposed amendment to clause 4.5.9(a)(ii) to change the determination of the largest contingency for the calculation of the reserve margin, in time for the next Reserve Capacity Cycle.

Consultation Questions:

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

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

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

3.1.4 Assessment of Unserved Energy

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

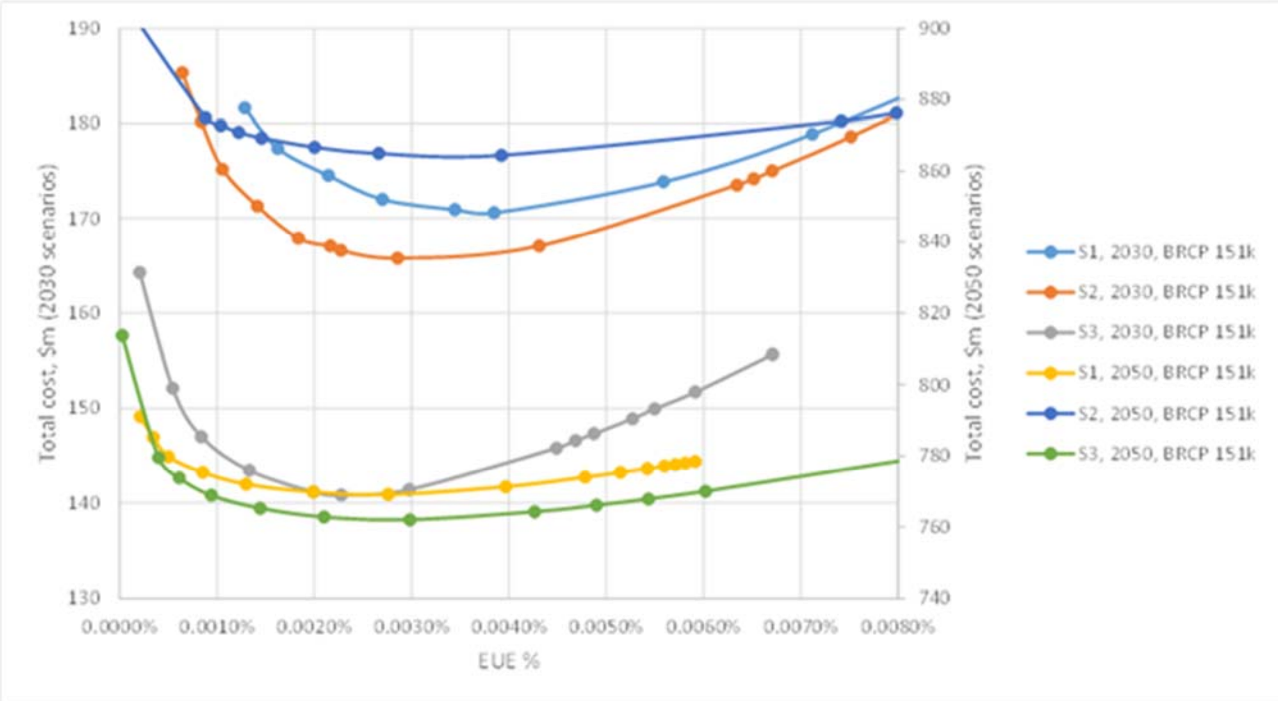
To determine an appropriate metric for the EUE limb (b) of the Planning Criterion, the trade-off needs to be explored between higher reliability requirements and cost, balancing the cost of unserved energy with the cost of new reserve capacity.

Resource adequacy modelling was used to find the EUE percentage at which the cost of unserved energy plus the cost of new capacity was at a minimum. This exercise used the fleet composition scenarios described in section 2.2.1, and price scenarios to consider a range of BRCPs, assuming that there is no surplus capacity (which is the assumption for setting the EUE target). The value of unserved energy ($48.10/kWh) is taken from Western Power's work on the Value of Customer Reliability (VCR) for the SWIS.[11]

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

Figure 11, Figure 10, and Figure 12 show the system costs for various levels of EUE under the various build scenarios. Costs are calculated as EUE (MWh) * VCR + RCP * added capacity (MW).[12] The lowest point on the curve is the optimal EUE target under that scenario.

Figure 10: System costs and EUE levels – BRCP 152k/MW



11 https://www.erawa.com.au/cproot/22440/2/AAI---Attachment-6.3---Estimation-of-value-of-customer-reliability-for-Western-Power-s-network.pdf

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

Figure 11: System costs and EUE levels – BRCP 117k/MW

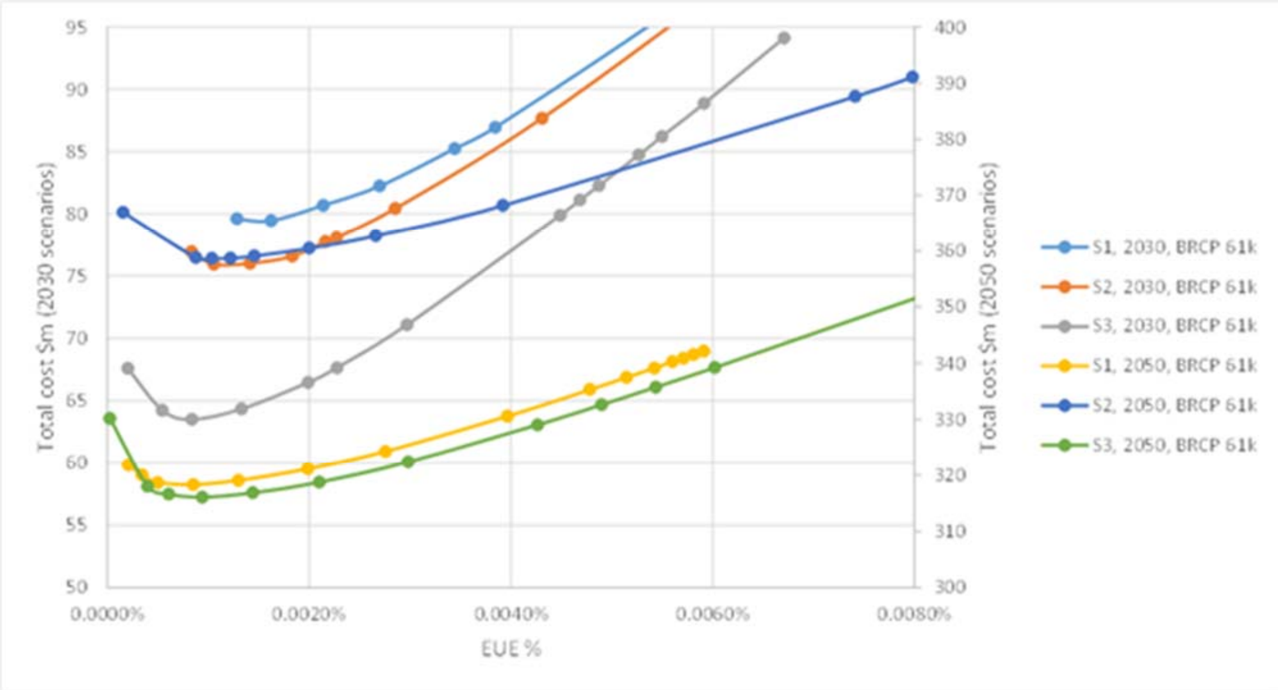
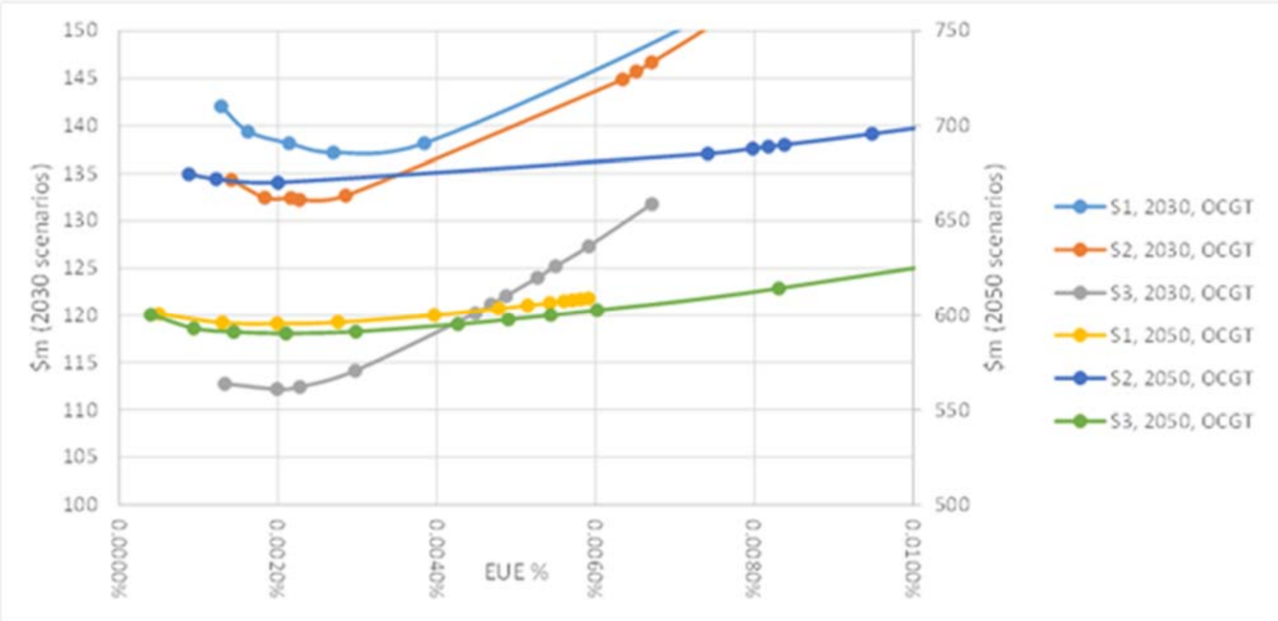


Figure 12: System costs and EUE levels – BRCP 61k/MW



Figures 10-12 show that:

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

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

Conceptual Design Proposal 7:

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

Consultation Questions:

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

3.2 Planning Criterion for Operational Reliability

3.2.1 The Need for Flexible Capacity

System stress modelling indicates that ramping needs will become more extreme in the future (see Figure 6). This need cannot be met by all capacity that is eligible for the existing 'Peak' capacity service. As shown in Figure 7, without a separate financial incentive, there may not be sufficient flexible capacity to move supply quickly from the low load in the middle of the day through to the evening peak.

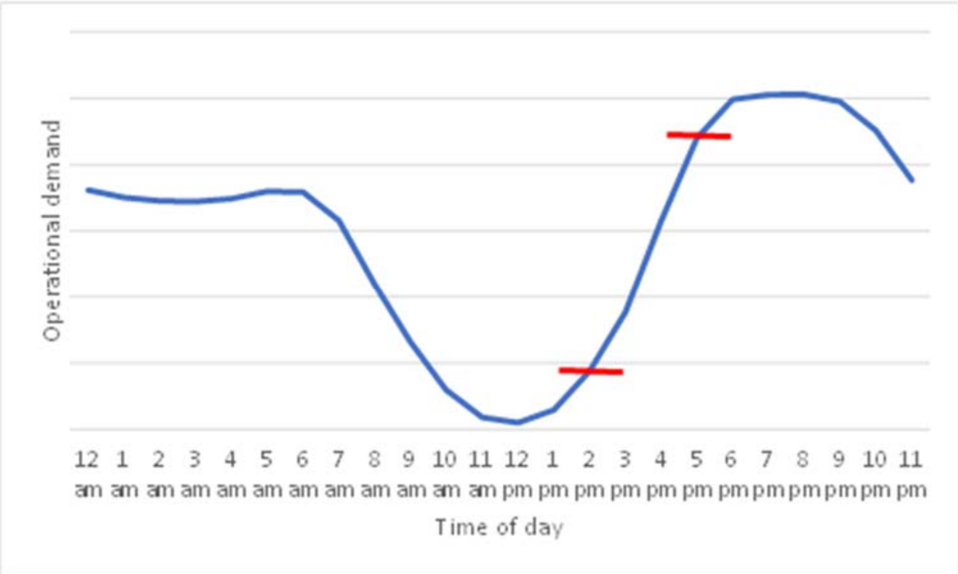
Capacity that can contribute to meeting the ramping requirements would likely also be capable of providing the range of Frequency Co-optimised Essential System Services (FCESS).

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

3.2.2 Setting the Target for Flexible Capacity

The key parameters driving the need for flexible capacity are the magnitude, slope, and duration of the most extreme ramp expected in the capacity year. The flexible capacity target would be set in the Electricity Statement of Opportunities (ESOO), based on the steepest ramp period expected, as shown by the red lines in Figure 13, which are marked at the start and end points of the steepest ramping period. These are not set at the absolute minimum and maximum, as the start and end of the ramp is at a shallower rate.

Figure 13: Basis for the flexible capacity target



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

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

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

Conceptual design proposal 8:

The 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.

Consultation Questions:

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

3.2.3 Proposal: Defining Flexible Capacity

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

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

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

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

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

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

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

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

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

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

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

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

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

4. The Benchmark Reserve Capacity Price

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

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

The administered RCP received by facilities holding Capacity Credits provides a signal of over- or under-capacity in the WEM.

Most aspects of the reserve capacity pricing arrangements are not in scope of this review. The methodology used to set the BRCP is in scope for both the existing Peak capacity product and the new flexible capacity product. The BRCPs must be considered in conjunction with STEM, real-time energy market and ESS market offer and price caps.

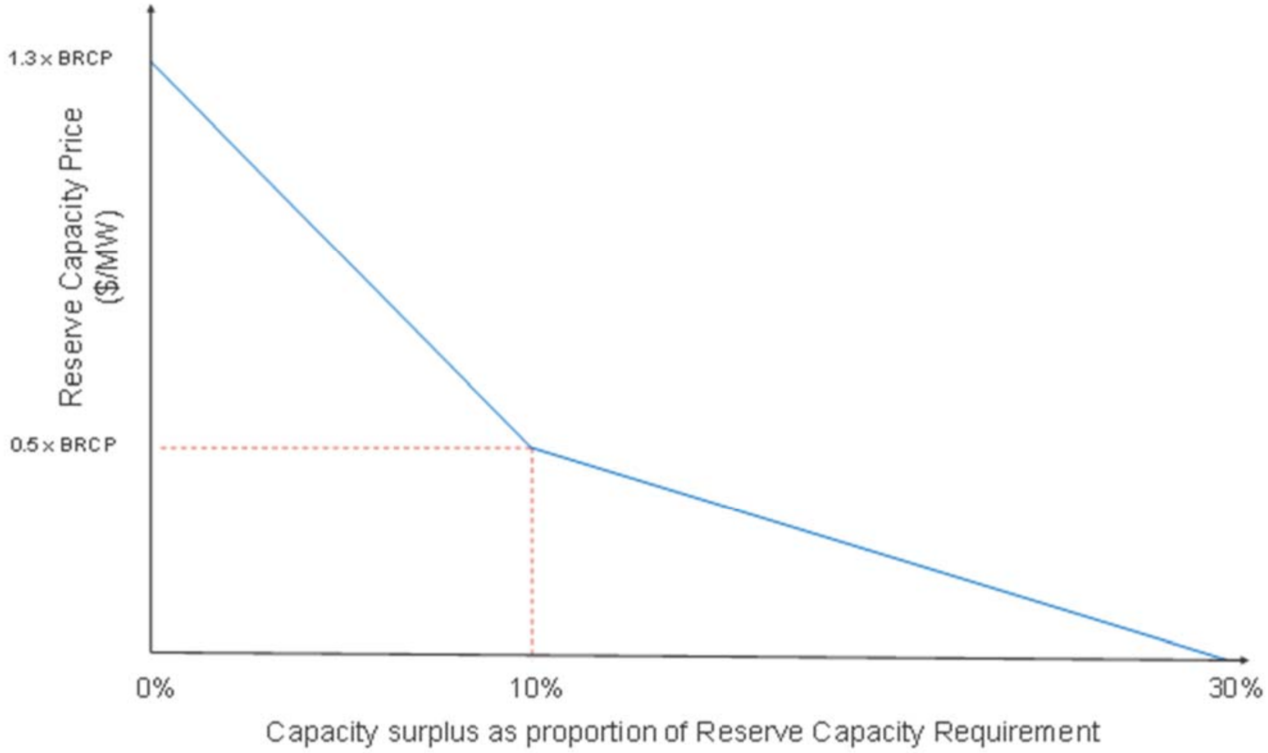
4.1 The Current BRCP Methodology

The BRCP is the anchor for the administered RCP. The monetary value of Capacity Credits is not affected by the technology of a facility[13].

As illustrated in Figure 14, depending on whether there is under- or over-supply of capacity, the actual administered RCP received by each facility may be greater than (up to 130% of) or less than (down to 0% of) the BRCP.

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

Figure 14: Administered capacity price curve



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

The WEM Procedure defines a specific power station to be used as the basis for the BRCP: a 160 MW liquid fuelled Open Cycle Gas Turbine (OCGT), the configuration of the station, and various commercial and financial parameters that are needed to determine the total fixed operating costs of the facility. The capital and fixed operating costs are annualized over a 15-year period and divided by the expected facility capacity at 41ºC to give a cost per MW of capacity.

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

It is considered that, while details of the BRCP determination can be delegated to a WEM Procedure, the WEM Rules should provide guidance or a high-level methodology for the BRCP.

The ERA's WEM Procedure: Benchmark Reserve Capacity Price[14] sets out the detailed methodology that determines the BRCP for each capacity year. The overall form of the BRCP methodology remains sound, including:

- the definition of the reference facility;
- the costs to be accounted for in determining the fixed cost of the reference facility, including development costs, transmission costs, and fixed operating and maintenance costs; and

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

- the method for annualising the facility fixed costs, including the weighted average cost of capital (WACC).

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

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

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

- de-rating for any intermittency;
- accounting for the effect of NAQs; and
- deducting expected energy and ESS revenue from total costs.

The current structure of the 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 calculation of net CONE.

Conceptual Design 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.

Consultation Questions:

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

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

4.2 Selecting a Reference Technology

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

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

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

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

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

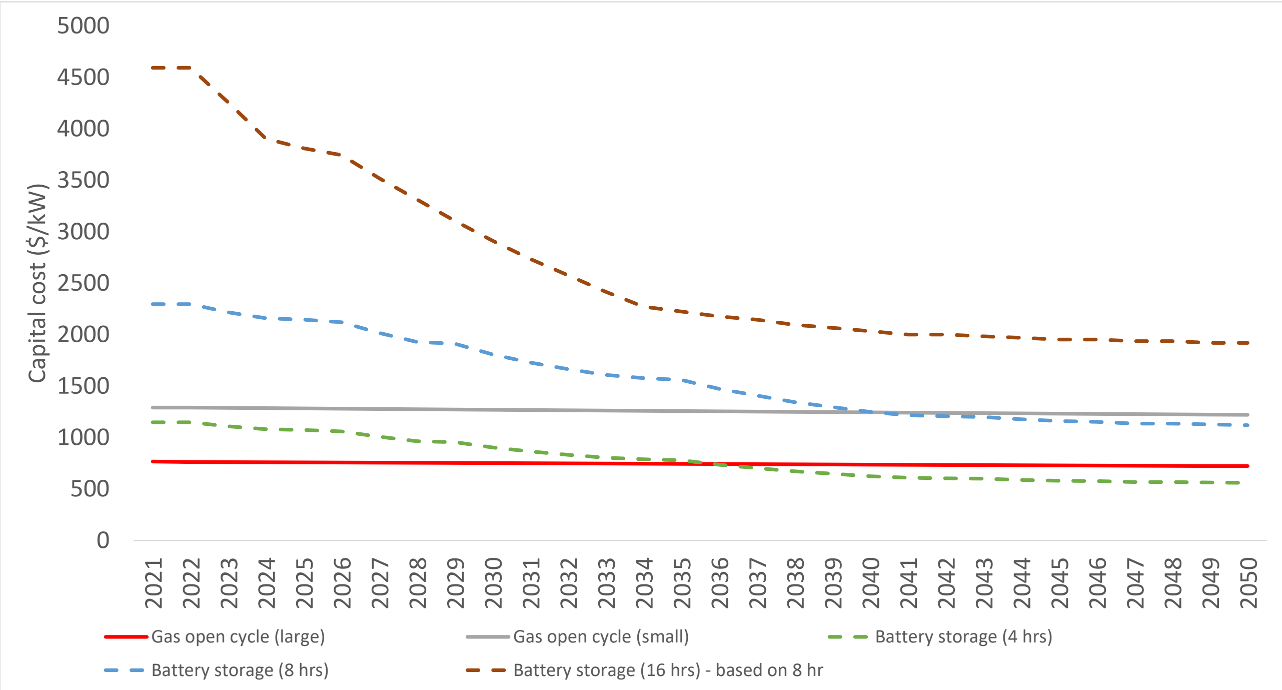
However, if the BRCP is set based on a lower cost technology that cannot be built in practice, the BRCP may be too low to encourage the marginal new entrant, resulting in a capacity shortage.

CSIRO's most recent generation cost report[15] shows that a large (~250MW unit size) OCGT remains the lowest capital cost option in 2022, while small (~50MW unit size) OCGT is more expensive. Costs for both are expected to decline modestly over the study horizon.

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

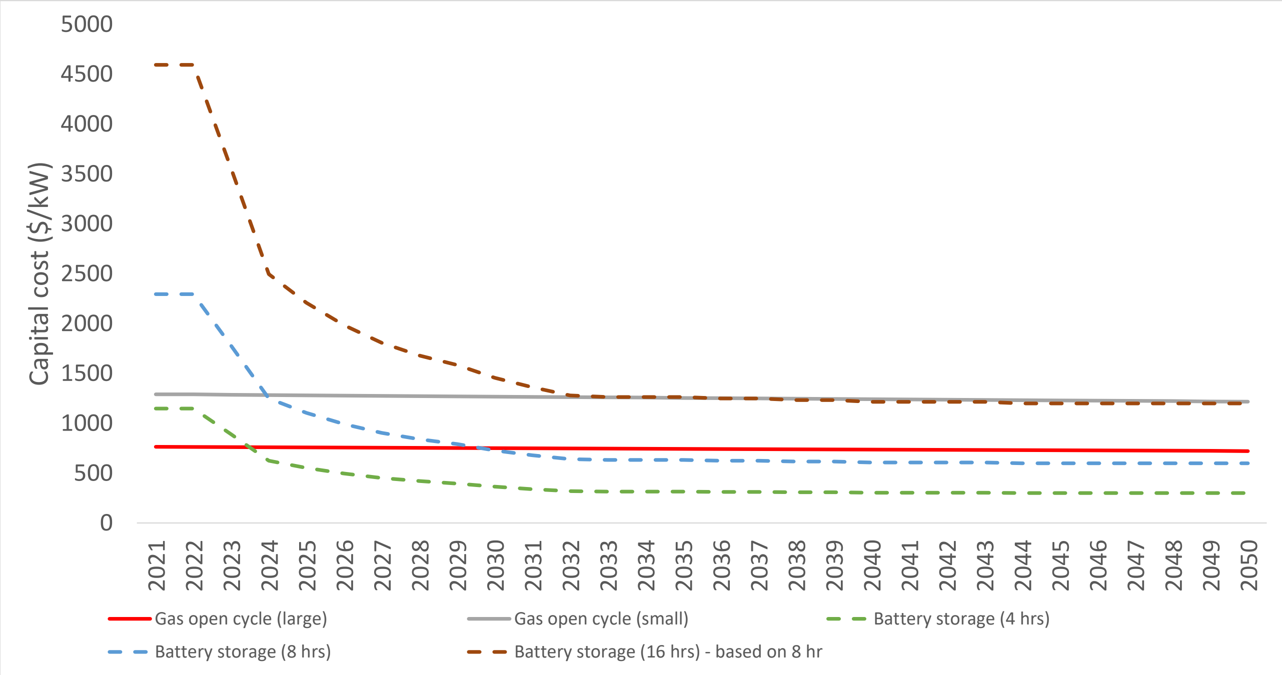
Figure 16 Figure 15 and Figure 17 show the estimated capital costs for OCGT and battery storage technologies from 2021 to 2050.

Figure 15: Technology capital costs - CSIRO current policies scenario



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

Figure 16: Technology capital costs - CSIRO global net zero by 2050 scenario

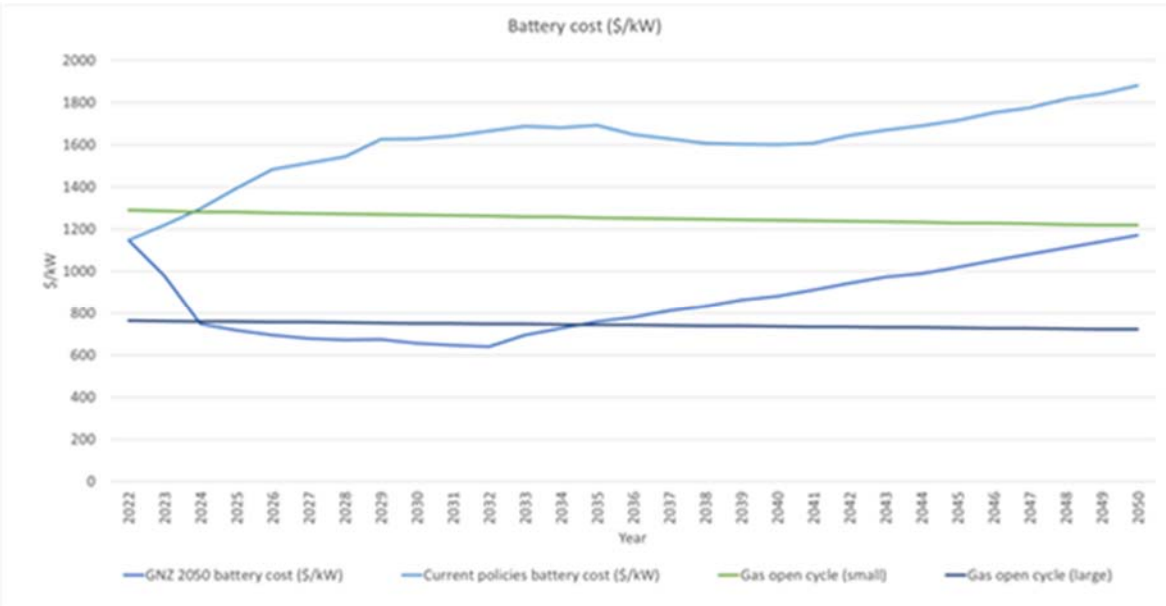


In the 'current policies' scenario (Figure 15), a four-hour battery is already lower cost to build than a small OCGT and will become lower cost than a large OCGT in the mid-2030s. In the 'net zero by 2050' scenario (Figure 16), a four-hour battery will become lower cost than a large OCGT in the 2020s, and an eight-hour battery will become lower cost than a large OCGT around 2030.

However, the situation is complicated because the required duration for storage will extend over time (see section 5.2 for further discussion). While four hours of storage will be sufficient for the next few years, eight hours of storage is likely to be needed by the early 2030s, and by 2050, storage will need to provide service through the peak and all the way through to the following morning.

Figure 17 shows capital costs for gradually extending battery storage lengths, starting in 2022 at the four-hour cost, then increasing the average length to reach eight hours in 2032, and then continuing to reach 16 hours in 2050.

Figure 17: Technology capital costs - blended battery storage lengths



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

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

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

The Minister's Draft Statement of Policy Principles: Penalties for high emission technologies in the Wholesale Electricity Market,[16] may also affect the capacity pricing regime. EPWA has not yet considered how to implement these policy principles, but initial direction is that they would be considered as part of the RCM Review and could be implemented through the RCM.

At some point battery storage of an appropriate length will become lower cost than an OCGT, or it will no longer be credible for OCGT to be built. At that point, the reference technology must change. This means that the ERA's periodic reviews of the BRCP methodology will become more important over the next decade, and the WEM Rules need to provide solid guidance to the ERA on the principles for setting the BRCP.

In the meantime, both OCGT and battery storage can be configured to provide flexible capacity, and 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 stable generation for example using sequential combustion to avoid diffusion mode combustion when using dry low NOx burners for emission control[17].

Conceptual Design Proposal 10:

- The WEM Rules will define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortised over the expected life of the facility.
- A BRCP is to be calculated for each of the Peak capacity product and the flexible capacity product, and the BRCP methodology must differentiate between the two, using the same basic reference technology.
- 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.

Consultation Questions:

(10)(a) Do stakeholders support proposed definition of the BRCP?

16 https://www.wa.gov.au/system/files/2022-08/Out-of-Session%20Meeting%20Papers.pdf.

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

(10)(b)	Do stakeholders support the calculation of separate BRCPs for the Peak and flexible capacity products?
(10)(c)	Do stakeholders support the proposed factors for the ERA to consider in reviewing the BRCPs?

4.3 Gross CONE vs Net CONE

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

EPWA has recently proposed[18] that the Max STEM Price (the highest allowable generation offer price in the STEM and real-time energy market) be set based on the highest short run cost facility in the fleet. This will continue the approach of allowing this highest-cost facility to recover all of its short-run costs when it runs, but not get a contribution to capital costs.

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

However, if at some point the marginal capacity provider no longer has the highest short-run costs in the fleet, then it will recover some contribution to its capital costs through infra-marginal rents in the energy and ESS markets. In the coming years, when battery storage is the marginal capacity provider but some OCGT peaking units remain in the market, the marginal new entrant storage facility would expect to earn more than its short run costs in the energy and ESS markets. This profit must be accounted for when setting the BRCP, or the BRCP will overestimate the marginal cost of new capacity entry. At that point, the BRCP would need to be based on the net CONE of the marginal capacity provider. The net CONE will likely trend back towards gross CONE over time, as the marginal capacity provider runs less frequently.

Economic modelling indicates that, in the 2020s, when storage volumes are small, storage facilities can make short-run profits by charging when prices are low or negative and discharging in the peak hours, even in a 50% POE peak demand year (see Appendix D for more detail). This means that setting the BRCP based on the gross fixed costs of a storage facility 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 will also be affected by the location of a facility. Where a new facility locates in a congested area of the network, its NAQ allocation will likely be less than its nameplate capacity. The types of capacity likely to be the reference technology are 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. As long as there is a location in the SWIS that can accommodate a new facility of the relevant reference technology and size, the NAQ regime should not impact on the per MW BRCP.

Conceptual Design Proposal 11:

- Where the RCM reference technology has the highest short-run costs in the fleet, the BRCP methodology can use the simpler gross CONE approach, as this will be the same as the net CONE.

[18] https://www.wa.gov.au/system/files/2022-08/Market%20Power%20Mitigation%20Strategy%20-%20Consultation%20Paper.pdf

- 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.

Consultation Questions:

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

4.4 Accounting for two Capacity Products

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

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

Pricing arrangements for the capacity products need to ensure that:

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

This could be arranged by:

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

It is considered that the last two options are equivalent, and clearer than the former options.

This means that the two capacity products would be treated as two separate but related markets: there will be two reserve capacity targets, two BRCPs, two capacity price curves, and two reserve capacity prices – one each for Peak capacity and flexible capacity products.

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

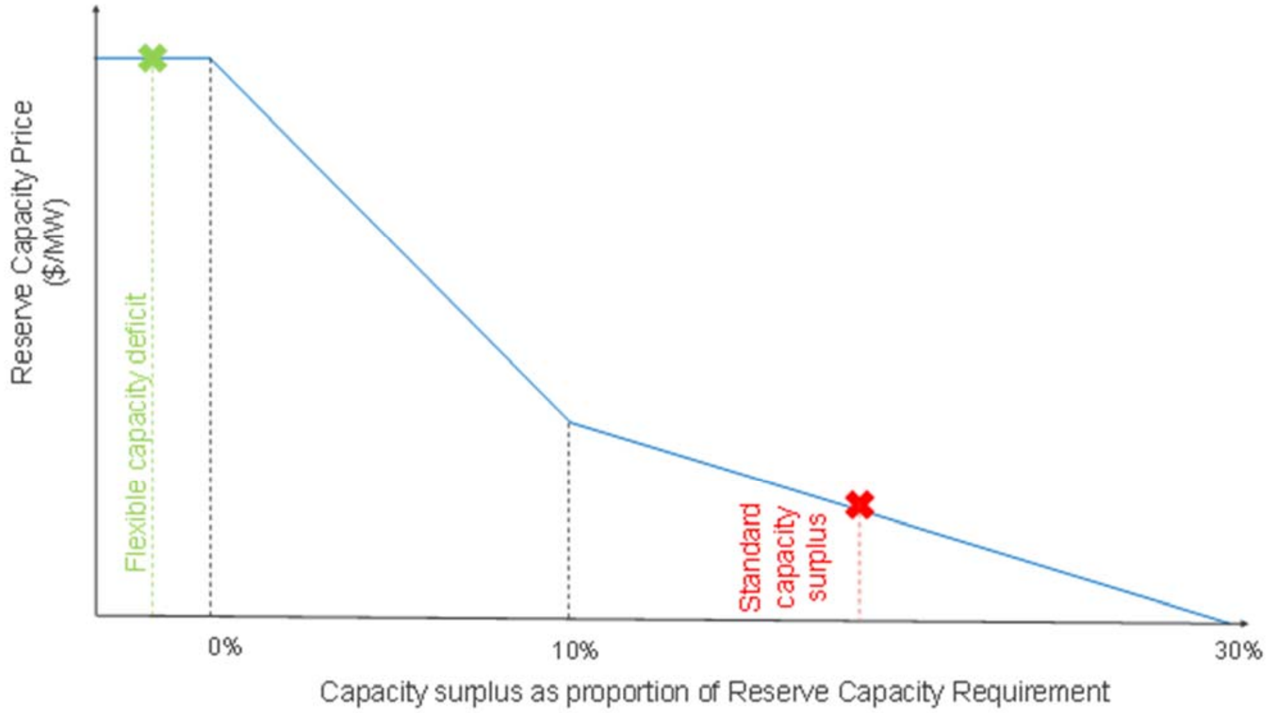
The definition of the administered price curve for the peak capacity product is out of scope of the review, but it is necessary to determine a price curve for the flexible capacity product. The price curve functions to:

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

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

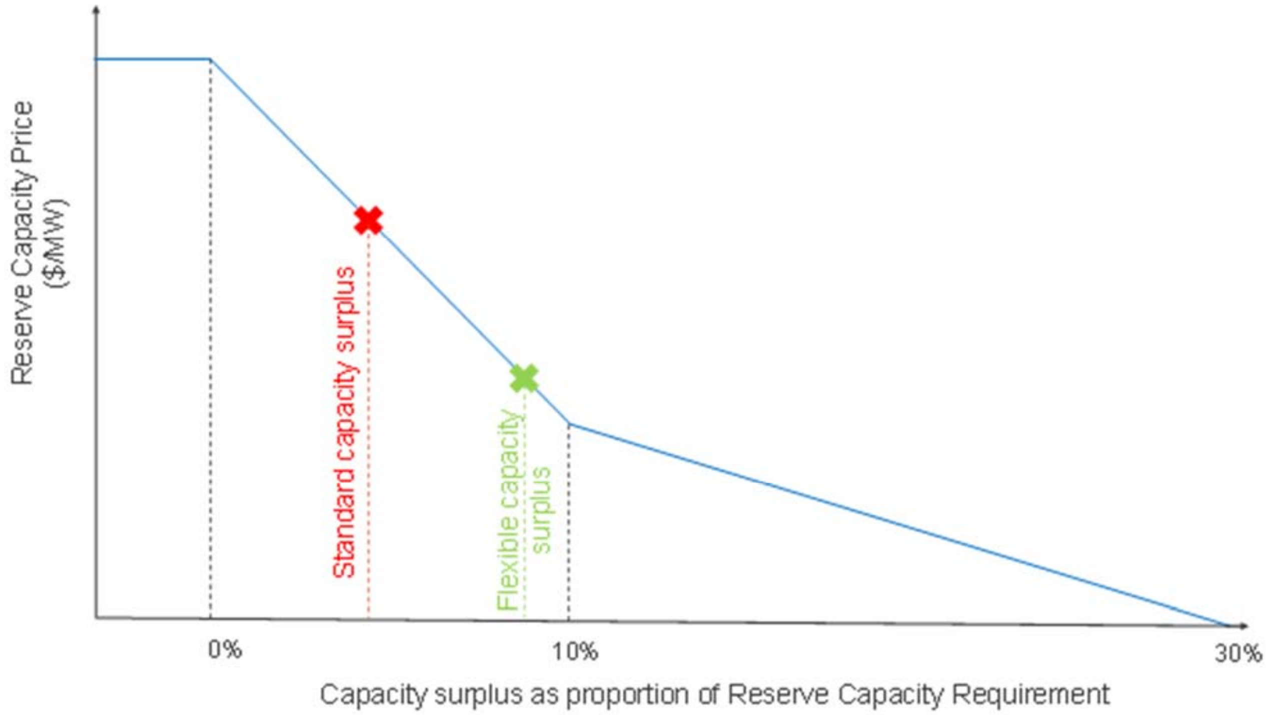
No compelling reasons were identified to use differently shaped price curves for the two products and so it is proposed to set the price curve for the flexible capacity product using the formula in WEM Rule 4.29.(b)(iv). Using the same shaped price curve means that the product with the higher relative shortfall (or lower relative oversupply) will have the higher price. For example, if there is a shortfall in flexible capacity and an oversupply of Peak capacity, the flexible capacity product would have the higher price (as shown in Figure 18).

Figure 18: Insufficient flexible capacity provided by existing facilities, facilities providing flexible capacity receive a higher capacity price



As long as facilities are paid at least the peak capacity price for the portion of their capacity that provides both services, when there is plenty of flexible capacity, overall capacity costs will be no more than they would have been in the absence of the flexibility product (as shown in Figure 19). Where there is a larger relative surplus of peak capacity than of flexible capacity, there would be additional costs associated with the flexible capacity product.

Figure 19: Sufficient flexible capacity provided by existing facilities, all facilities receive standard capacity price



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

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

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

Conceptual Design 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.

Consultation Questions:

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

(12)(b)	Do stakeholders support the proposed pricing arrangements for the peak capacity product?
(12)(c)	Do stakeholders support a 5-year fixed price option for facilities capacity prices?

5. Capacity Certification

5.1 Valuing Capability when Certifying Capacity

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

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

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

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 aligns capacity allocation with firmness of delivery and with availability obligations. There will be three capability classes:

- Class 1: Unrestricted firm capacity

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

- Class 2: Restricted firm capacity

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

- Class 3: Non-firm capacity

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

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

- all existing and committed facilities in all classes would be able to trade their Capacity Credits;
- new proposed facilities would only be able to trade their Capacity Credits if there were insufficient existing and committed facilities to meet the Reserve Capacity Target for that Capability Class; and

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

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

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

Participants would be required to show that each facility receiving CRC in Capability Class 1 has sufficient certainty of fuel access (through a combination of onsite fuel storage[19] and fuel delivery contracts[20]) to deliver service for up to 14 hours, and not being able to do so would affect Capability Class allocation.

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

It is considered that a 14-hour running requirement to qualify as firm, unrestricted capacity is still valid. The requirement was originally put in place to ensure that liquid fuelled facilities had sufficient onsite fuel to operate for 4-5 hours a day for three days, without resupply. This consideration is still relevant, as system peak events in recent years have occurred over several days during periods of sustained high temperatures and high demand.

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

For these reasons, it is considered that it is reasonable to retain the 14-hour requirement for facilities in Capability Class 1. However, the new capability class arrangements mean that owners of existing facilities could choose to contract for less than 14 hours of fuel 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.

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

As noted in section 4.2, at some point in the 2030s or 2040s, it may be necessary to require storage facilities to demonstrate their access to energy to charge, or to amend their capability

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

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

classes to differentiate between facilities that simply time-shift energy from those which actually produce it.

Conceptual Design Proposal 13:

- The current Availability Classes will be removed from the WEM Rules.
- The RCM will allocate facilities to one of three Capability Classes as described.
- 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.

Consultation Questions:

(13)(a) Do stakeholders support to replace the current Availability Classes with Capability Classes?

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

(13)(c) Do stakeholders support retaining the 14-hour fuel requirement and the all-hours availability requirement for Capability Class 1?

5.2 The Duration Gap

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

Modelling indicates that firm capacity will be needed by 2030 to shift energy from the middle of the day to the peak period, with a total duration of around six hours, but in 2030 there will likely be sufficient gas fuelled facilities to fill most of the overnight need (along with a contribution from wind), meaning that storage facilities which can discharge over the few peak hours are sufficient to serve load and achieve adequate reliability. By 2050, with all thermal generation retired, the overnight gap must be filled primarily by wind, storage, and DSM across a total duration of around 14 hours.

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

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

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

- Load is at the forecast 10% POE day operational load shape and magnitude;
- existing and committed capability Class 1 capacity is fully available, but the total available capacity is derated by the same overall fleet outage rate used to calculate the reserve margin in the reserve capacity target;
- selected existing and committed capability Class 2 capacity is available for its certified duration; and

- existing/committed Class 3 facilities output is per their CRC.

The availability duration target would be calculated as the length of the period in which this capacity is not sufficient to meet the load[21], and Capability Class 2 availability obligation hours would be set accordingly.

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

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

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

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

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

Once the fixed-duration period was over, the facility would no longer be included in the calculation of the availability duration requirement and would receive CRC based on de-rating over the prevailing availability duration requirement.

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

21 With a minimum of four hours, to match the current ESR obligation period.

High level design proposal 14:

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

Consultation Questions:

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

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

(14)(c) Do stakeholders support providing for proponents to request a 5-year fixed availability requirement.

5.3 Accounting for Forced Outages

5.3.1 ICAP

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

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

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

5.3.2 UCAP

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

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

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

This UCAP implementation bases capacity allocation on historical performance that will not necessarily reflect future performance. EFORd can also be assessed on a forward-looking basis, either by adjusting historical outage data to remove uncharacteristic outages[22], or by using representative outage rates from similar facilities.

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

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

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

UCAP for scheduled facilities is equivalent to an Effective Load Carrying Capability (ELCC) approach, where the contribution of the facility is adjusted based on actual performance, as long as the facility's chance of outage is not correlated with weather events.

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

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

Appendix C shows an example calculation of UCAP using outage and service data for 2012 to 2022. In this example, total Capacity Credits allocated would reduce by 8.7%[23].

5.3.3 Discussion

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

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

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

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

Moving to a UCAP approach would require changes to either:

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

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

The rules already make provision for facilities to have their CRC adjusted where forced outage rate exceeds a threshold (WEM Rule 4.11.1D), but this is restricted to facilities with a forced outage rate of more than 10% over the previous three years. AEMO has not exercised this option. It is assumed that this is because the rules do not provide guidance on the appropriate circumstances to exercise this discretion.

It is considered that:

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

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

Conceptual Design Proposal 15:

- CRC allocation will remain on an ICAP basis, with refunds payable for any forced outage.
- The reserve margin in the first limb of the Planning Criterion will be set at the greater of the fleet-wide EFORd and the largest contingency expected at system peak, with AEMO assessing both each year 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.

Consultation Questions:

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

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

5.4 CRC Assignment

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

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

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

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

5.4.1 The Need to Better Reflect Contribution to System Reliability when Assigning CRC to Intermittent Generators

The current RLM was designed for an environment where intermittent generation made up a small proportion of the fleet. It uses constant parameters in the calculation (the k and the u factors), the purpose and calculation of which is not defined under the market rules. Market Participants and new entrants to the SWIS cannot determine the value of these parameters. The current RLM is inconsistent with the Planning Criterion, because it focuses on performance in periods that do not directly relate to system stress intervals. Increased penetration of intermittent generators in the system will exacerbate the issues with the current RLM[24].

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

Ideally, a CRC allocation method for intermittent generators would:

- accurately reflect facility performance in periods of system stress;

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

- account for the correlation of output between facilities in the same location or affected by the same weather conditions;
- ensure those who are best placed to manage the risk of volatility in intermittent generator output are exposed to that risk; and
- minimise CRC volatility between years where appropriate.

5.4.2 The need to Change the Approach for Assigning CRC to Demand Side Programmes

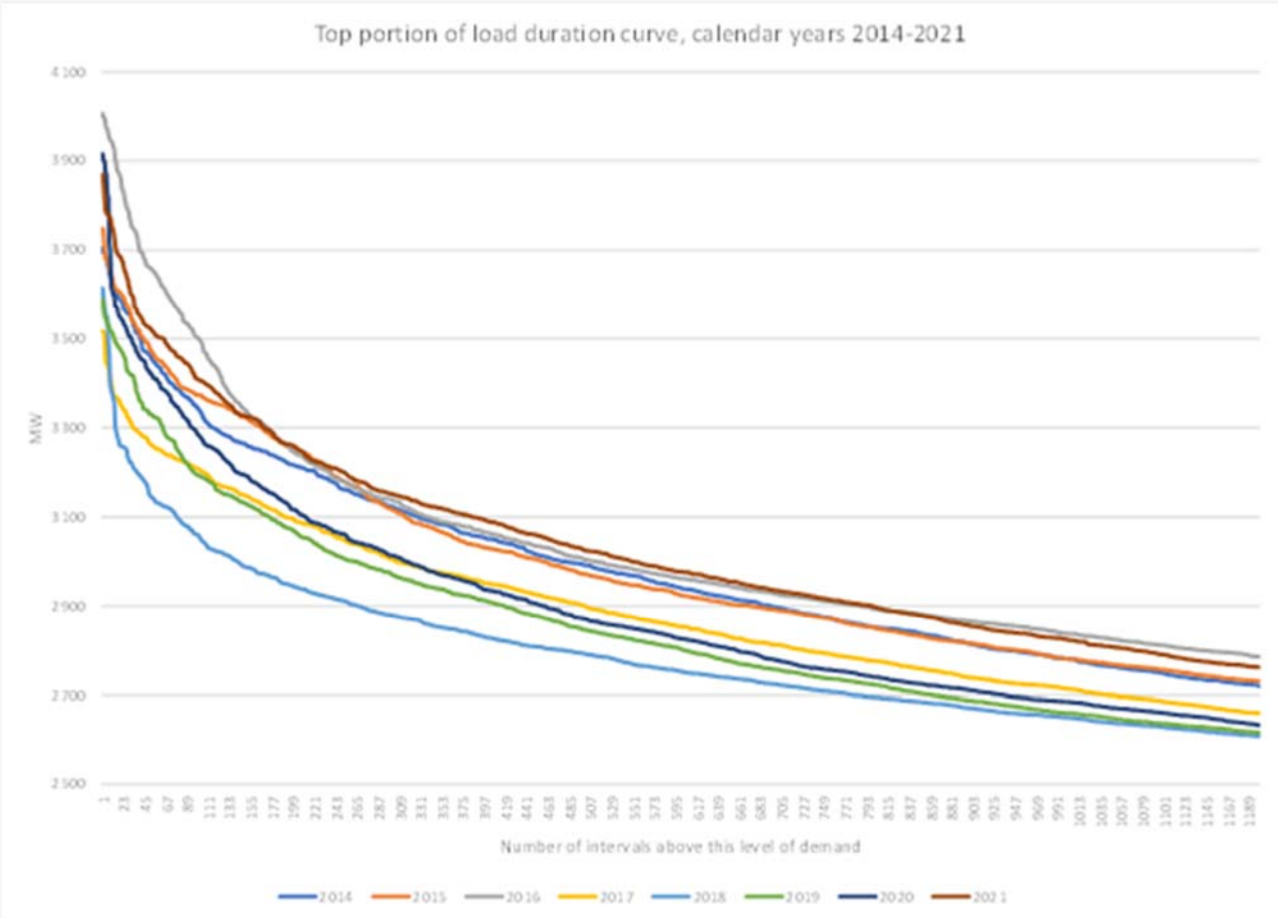
The current method for assessing the reliability contribution of Demand Side Programmes is also problematic. It assesses potential performance at times of high demand periods, but these periods are not aligned with the periods used for intermittent generation or the allocation of IRCR.

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

5.4.3 Intermittent Generator Performance in System Stress Periods

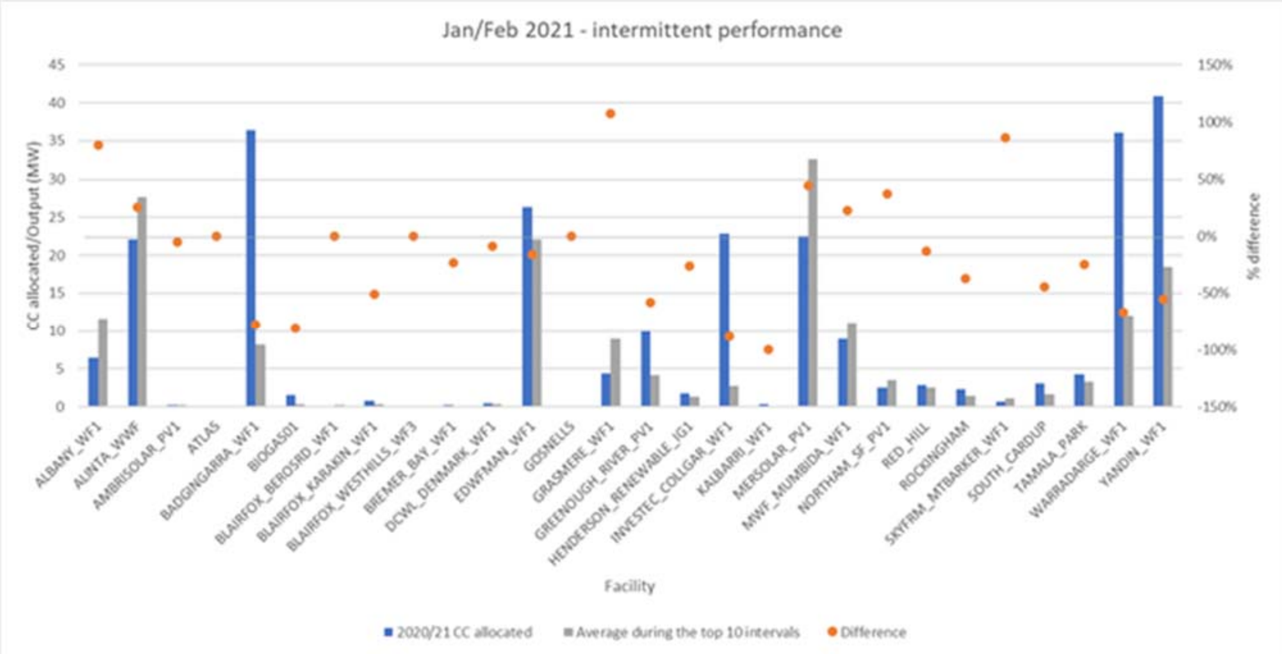
WA experiences extreme system stress events very infrequently, and not all years have the same level of stress. For example, 2016 had 47 hours with higher demand than the 2017 peak. Figure 20 shows the 1200 hours with the highest load for each calendar year from 2014 to 2021. Each year has a very small number of intervals with very high load, and in some years the load reaches a considerably higher level than in others.

Figure 20: Peak portion of load duration curve by calendar year



Weather drives both demand and intermittent generation, so performance in historic stress intervals is the only real measure of expected performance in future stress intervals. For example, as shown in Figure 21, intermittent facilities performance during the 2021 summer peak intervals was below the level of capacity credits allocated.

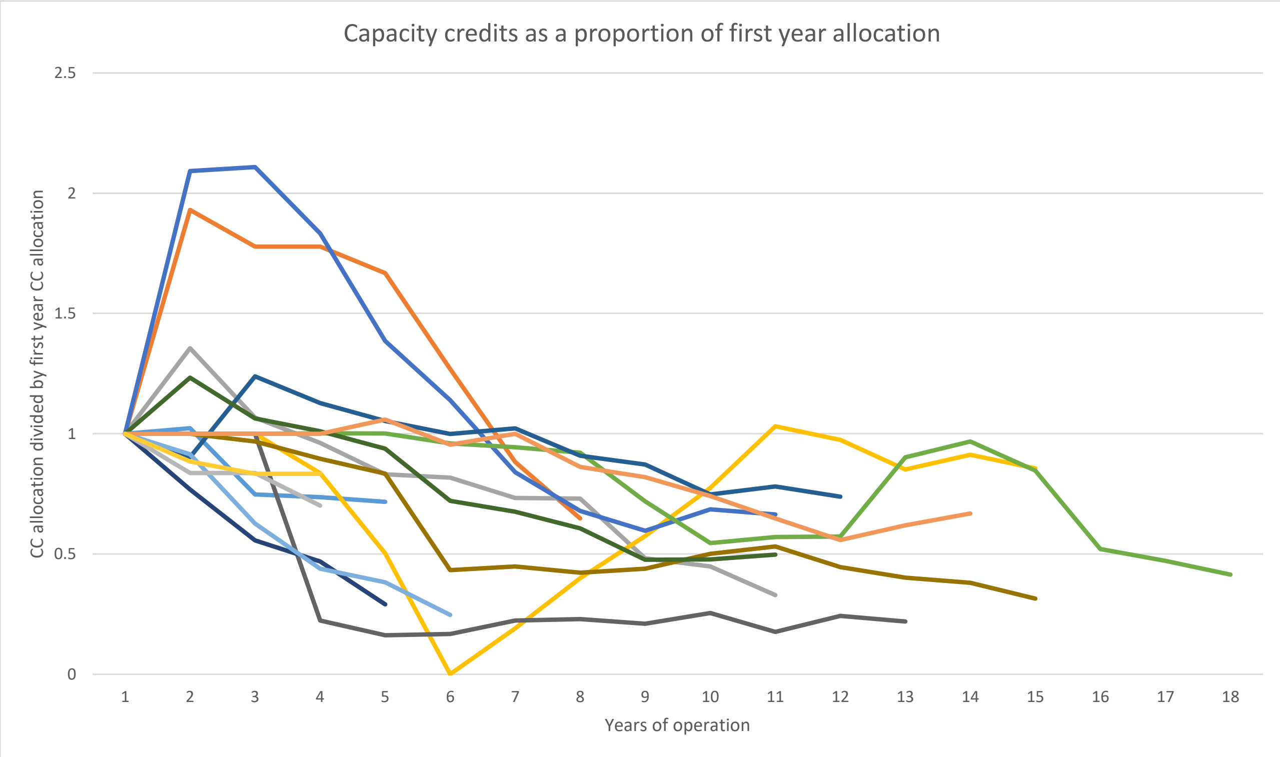
Figure 21: Intermittent facility performance in Jan/Feb 2021 peak periods



Expert Reports

CRC assessment for new intermittent facilities is reliant on expert reports of estimated output during stress events. While the overall trend in capacity allocation is affected by many factors, Figure 22 Shows how intermittent facility CRC changes over time from the CRC it was allocated in its first year of operation (based solely on expert reports). Some facilities see a significant decline in their CRC over the first five years of operation (the period during which expert reports are used) and then stabilise.

Figure 22: Capacity credit allocation for intermittent facilities



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

Conceptual Design 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.

Consultation Questions:

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

5.4.4 Alternative approaches to Certifying the Capacity Contribution of Intermittent Facilities

Effective Load Carrying Capability

As seen in the international review published alongside this consultation paper, the contribution of intermittent facilities is sometimes assessed through probabilistic methods, including effective load carrying capability (ELCC[25]), equivalent firm capacity (EFC), and the marginal reliability index (MRI).

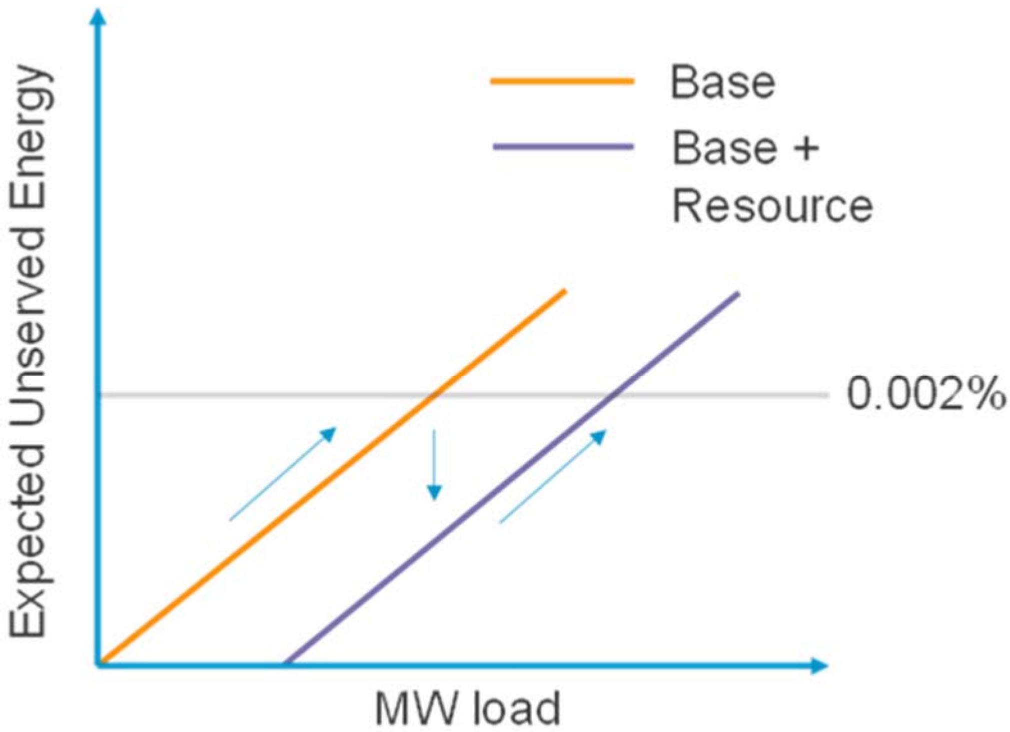
Under these approaches, intermittent facility CRC is based on actual contribution to system reliability, accounting for expected facility output at times of system stress.

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

The ELCC of a Facility represents the amount of load that can be added to a system if this Facility was added to the system, without increasing the system's LOLE. That is, the ELCC is determined as the firm capacity that could replace the assessed intermittent generator without changing the system's LOLE. The process is as follows, and is illustrated in Figure 23:

1. take a historical load profile and adjust so that it reflects the underlying demand before any loss of load or DSP dispatch;
2. determine the expected lost load (for example adjust load to derive 0.002% EUE, or the desired LOLE measure) in a base case that does not include the candidate facility;
3. add the candidate facility to the base case;[26]
4. adjust load (using a flat profile and increment every interval with the same amount) until expected lost load is back to the same level as in the base case; and
5. calculate ELCC for the facility as the MW of load added.

Figure 23: ELCC method



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

A facility's ELCC can be affected by the characteristics of other facilities in the fleet. Where intermittent output is correlated, additional facilities of that type will contribute less and less to system reliability. For this reason, the ELCC for a particular facility will differ depending on whether it is assessed in the presence or absence of other similar facilities. For example, the first solar facility in a power system will have a very high proportion of its output contributing to meeting the load. The twentieth large solar facility is much less likely to contribute, as there is already an

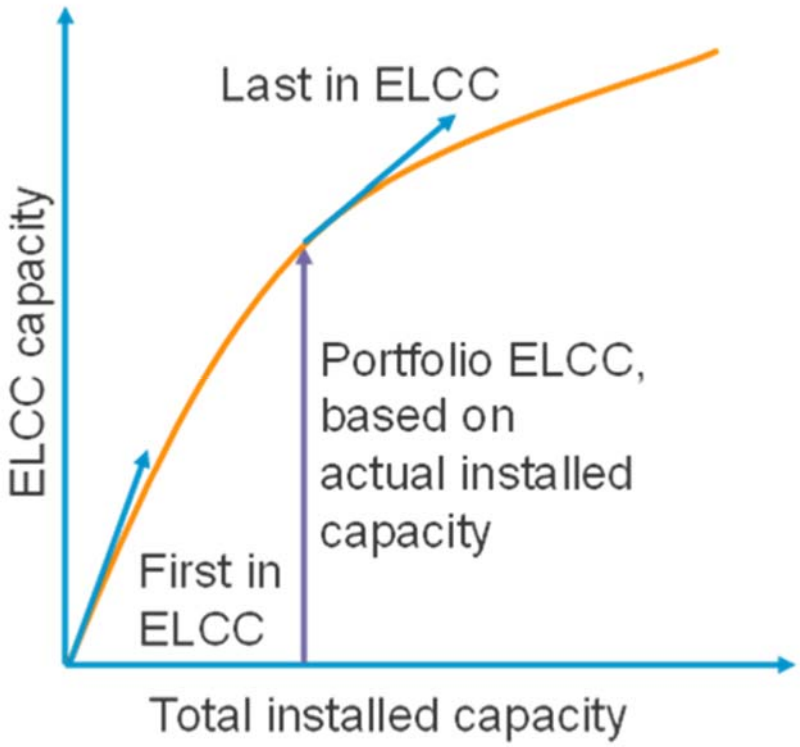
26 For intermittent generators, this means adding the facility's expected or historical generation profile to the base case,

oversupply of facilities generating during daylight hours. Similarly, as more wind farms are built in the same geographical area, the correlation between their output means that each subsequent MW contributes less to system reliability.

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

Figure 24 illustrates how the Facility ELCC can change depending on the characteristics of the fleet. This change can be positive or negative, depending on whether the facility being assessed complements the rest of the fleet.

Figure 24: First in and last in ELCC



To ensure that the total allocated ELCC matches the ELCC of the fleet as a whole, the first in and last in facility ELCCs can be used to allocate the fleet effect according to the “delta method” as follows[27]:

1. For each individual facility, calculate:
    a. the First-In ELCC, which is the ELCC of the individual facility excluding the other facilities (i.e. as if the individual facility was the first facility used to meet system demand); and
    b. the Last-In ELCC, which is the ELCC of the individual facility including the other facilities (i.e. as if the other facilities have already reduced demand);
2. Determine the Interactive Effect as the fleet ELCC less the sum of all facilities’ Last-In ELCCs;

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

3. Determine the Delta for each facility as its First-In ELCC less its Last-In ELCC;
4. For each facility, determine its Interaction Effect Share as the facility's Delta multiplied by the Interactive Effect and divided by the sum of all Deltas; and
5. For each facility determine the ELCC as its Last-In ELCC plus its Interaction Effect Share.

This can be represented by the following equation:

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

Where:

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

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

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

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

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

Non-Probabilistic Method

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

The RCMRWG proposed that a non-probabilistic method could reduce this uncertainty, with one of the group members suggesting[28] that it could be calculated as follows:

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

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

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

1. take a set of historical load data over five years (adjusted to remove effects of any load shedding or DSP dispatch, and adjusted to reflect penetration of solar PV generation in the reference year);
2. sort the intervals in order of load minus intermittent generation to produce a multi-year lowest-scheduled-generation (LSG) duration curve[29];
3. select the highest intervals (for example, the top 5%) as representative of system stress events; and
4. for each relevant facility:
    a. find the facility output (adjusted for any curtailment) during those intervals
    b. sort in order of facility injection
    c. find output at a given percentile output in those intervals; and
    d. set the CRC of the facility at the maximum of that value and zero.

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

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

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

Alternative Hybrid ELCC Method

The RCMRWG also discussed an alternative hybrid ELCC method, whereby the overall fleet capability was calculated using the ELCC method, and this total ELCC is allocated according to a non-probabilistic method. Another member of the group proposed[30] that this be calculated as follows:

1. take load and facility output data for each of the five previous capacity years
2. calculate the annual fleet ELCC for each year
3. determine the fleet ELCC as the mean of the annual fleet ELCC values
4. select the 12 days from each year with the highest demand and then the four intervals with the highest demand in each of those days, for a total of 240 intervals (around 0.5% of intervals);
5. for each facility, calculate the facility performance level as the mean of its output in the selected intervals;
6. calculate scaling factor R as the fleet ELCC divided by the sum of facility average performance levels; and
7. for each facility, determine CRC as the scaling factor multiplied by the facility average performance level.

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

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

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

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

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

1. take load and facility output data for the five previous capacity years;
2. calculate the fleet ELCC using the load trace for the whole period to avoid giving undue weight to non-stress intervals in years where the peak demand is low;
3. sort the load trace in order of operational demand less intermittent facility output to produce a multi-year LSG duration curve[31];
4. select the highest intervals (for example, the top 0.5%) as representative of system stress events;
5. for each facility, calculate the facility average performance level as the higher of zero and the mean of its output in the selected intervals;

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

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

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

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

5.4.5 Discussion

It is considered that simple methods of CRC assessment remain appropriate for Class 1 and 2 facilities[32], but that an alternative method may be appropriate for Class 3 facilities. Table 2 compares the discussed methods against the guiding principles specific to the RCM Review.

Table 2 provides a preliminary qualitative assessment of the three alternative CRC methodologies for intermittent generation.

Table 2: Qualitative Assessment of Alternative CRC Methodologies for Intermittent Generation

Principle	Delta Method	Non-Probabilistic Method	Hybrid ELCC Method
Enable the orderly transition to a low greenhouse gas emissions economy	✓ All methods provide support for low-emission technologies. The degree to which they support an orderly transition is affected by the factors below.	✓	✓
Ensure sufficiently reliable capacity is available to meet the capacity requirements	✓ CRC is based on performance at times of actual system stress, aligned with Planning Criterion.	– CRC is based on performance in a range of intervals, some of which are not taken from system stress events.	– Total quantity of CRC is based on fleet performance during system stress events, but individual facility allocations are not.
Cost-effective	✓ Total CRC allocated matches combined fleet capability.	– Total CRC allocated may be more or less than the combined fleet capability to serve load, meaning that consumers may overpay for capacity that does not perform.	✓ Total CRC allocated matches combined fleet capability.

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

Principle	Delta Method	Non-Probabilistic Method	Hybrid ELCC Method
Simple	✗ Probabilistic assessment requires moderately complex assessment tool.	✓ Non-probabilistic method requires only simple mathematical functions with data readily available to individual participants. Provides some continuity with existing RLM.	✗ Method combines both approaches, meaning that it is more complex than either alone.
Flexible	✓ Method is flexible to changing load and generation profiles. Aligns with evolving practice in capacity markets internationally.	– Method requires review every few years to ensure that intervals selected are representative.	–
Able to be maintained on an ongoing basis	✓ All methods can be maintained over time, although some may require more frequent review (see above).	✓	✓
Provide investment signals	– Potential for year-to-year volatility in CRC allocation for facilities with volatile output. Provides clear signal for participants with volatile facilities to invest in reducing that volatility and firming their output.	✓ Less potential for year-to-year volatility of facility CRC, meaning risk is shifted from participants to customers.	✓
Provide locational signals	✓ Facility CRC accounts for correlation between the output of multiple facilities, rewarding facilities that complement the existing fleet.	– Method needs to use LSG rather than load in order to account for facility output correlations. This may depart further from system stress intervals.	–

Principle	Delta Method	Non-Probabilistic Method	Hybrid ELCC Method
Provide technical capability signals	✓ Directly aligned with planning criterion, incentivising availability at times of system stress.	× Increased risk of mismatch between CRC allocated to a facility and its actual contribution to system reliability in system stress events.	×

EPWA will continue quantitative analysis of the CRC methods proposed, using common assumptions to ensure comparability, and propose a preferred option during stage 2 of the RCM Review.

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

Conceptual Design Proposal 17:

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

Consultation Questions:

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

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

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

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

Appendix A. RCM Review Current Timetable

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

Task/Milestone	Timing
Consultation paper(s) on the detailed RCM design and Rule Change Proposals and a request for stakeholder consultation.	May 2023
Publish a final Information Paper on the proposed detailed revised RCM design.	June 2023
Submit Rule Change Proposal for consideration and approval by the Coordinator and Minister.	June 2023

Appendix B. Modelling Approach

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

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

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

B.1 Modelling Tools

Two modelling tools were used:

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

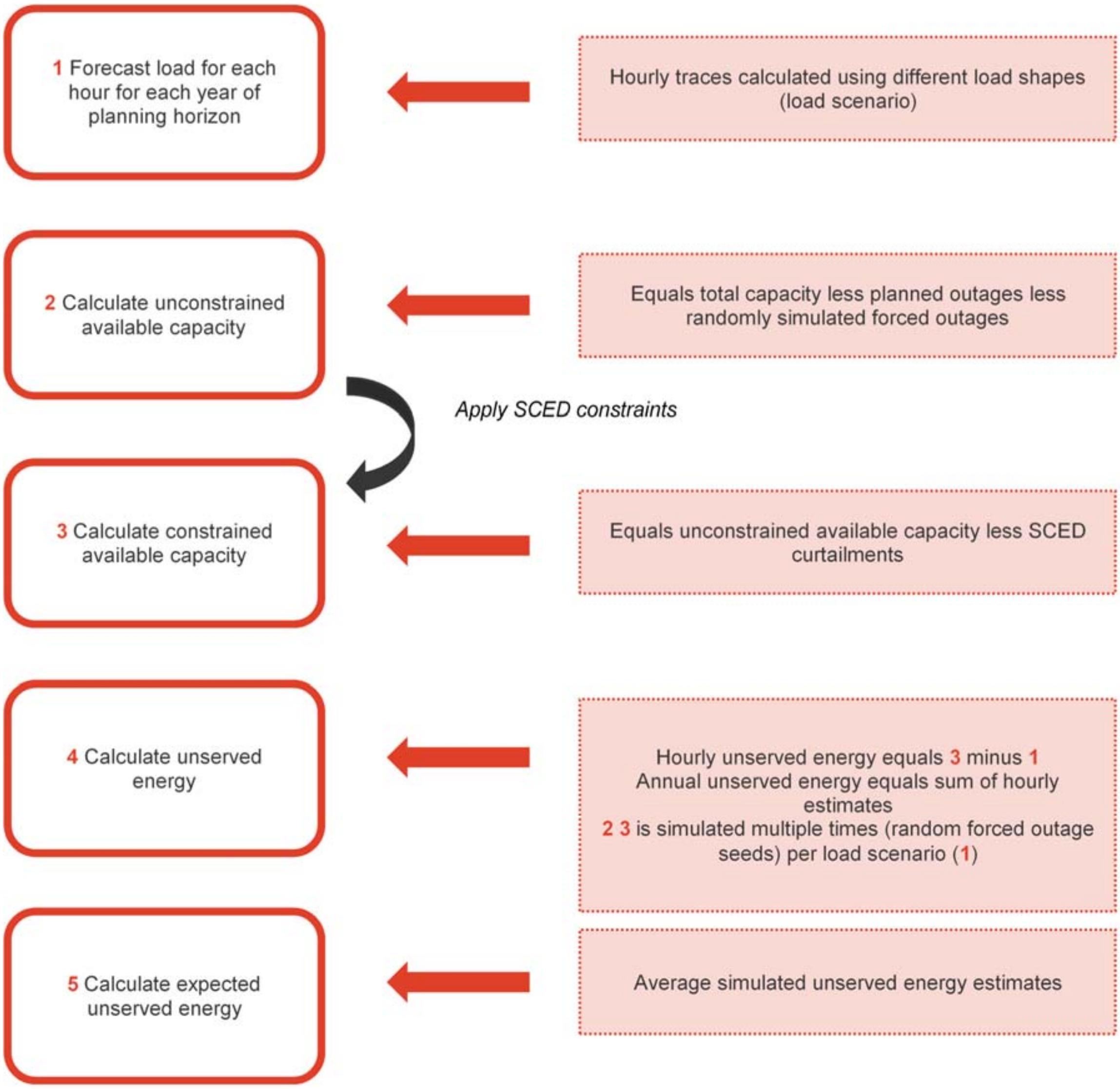
B.1.1 CAPSIM

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

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

As shown in Figure 25, the hourly demand for the forecast period is calculated based on historical data. The different load shapes from the previous years are used to develop a forecasted load curve. The unconstrained capacity is the total capacity available in the system while taking into account planned outages and forced outages. Forced outages are randomly simulated based on historical outage data. The constrained capacity is calculated from the unconstrained capacity by accounting for transmission constraints. Finally, the model calculates the unserved energy during periods when the total generating capacity is less than the total demand, leading to unserved energy. The total expected unserved energy is the average of the unserved energy during the forecast period.

Figure 25: CAPSIM Overview



B.1.2 WEMSIM

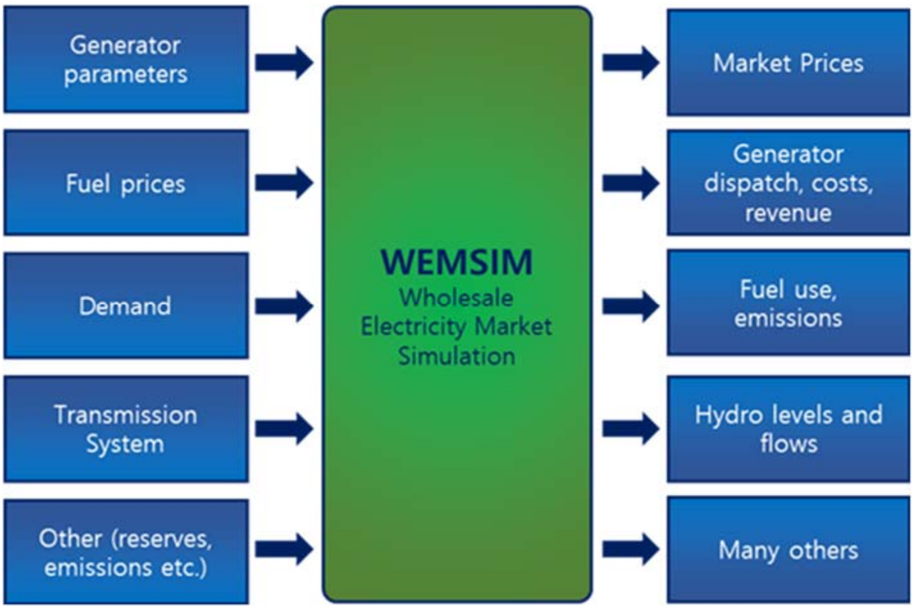
WEMSIM (Wholesale Electricity Market SIMulation) is an analytical dispatch planning and analysis tool that simulates the dispatch of generation resources in a multi-regional transmission framework. WEMSIM is an optimization engine based on linear and mixed integer (MIP) programming. WEMSIM simultaneously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

WEMSIM co-optimises energy dispatch and reserve provision using:

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

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

Figure 26: WEMSIM Overview

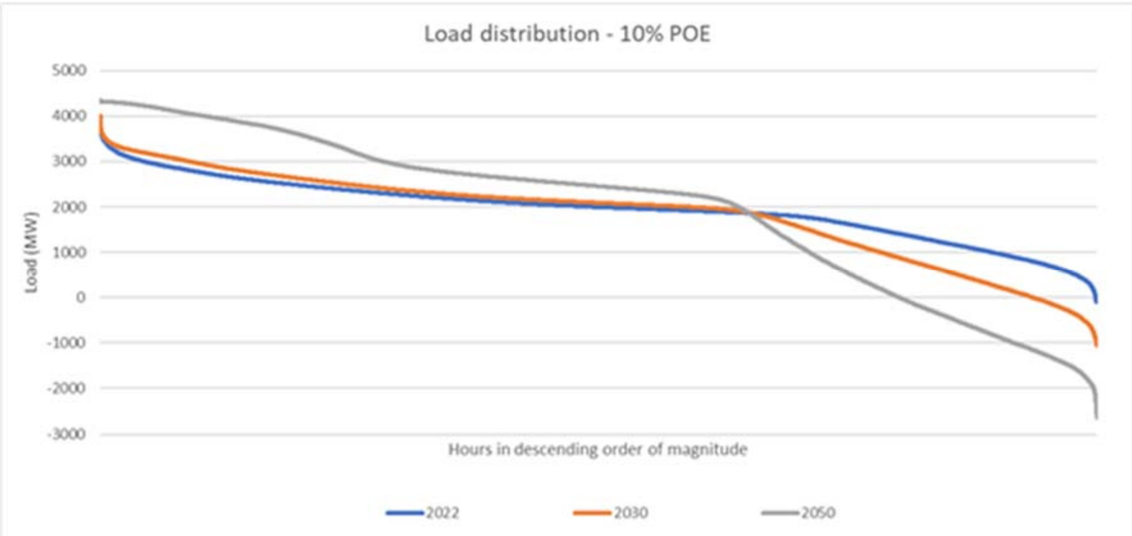


B.2 Demand Forecast

Modelling used the demand forecasts from AEMO's 2021 ESOO[33] for 2022 and 2030 and extrapolated to 2050 assuming there will be some optimisation of electric vehicle charging. Modelling considered both the 50% POE load forecast and the 10% POE load forecast, to understand how system stress events differ depending on the load.

Modelled load duration curves for the 10% POE case are shown in Figure 27.

Figure 27: Load Duration Curves



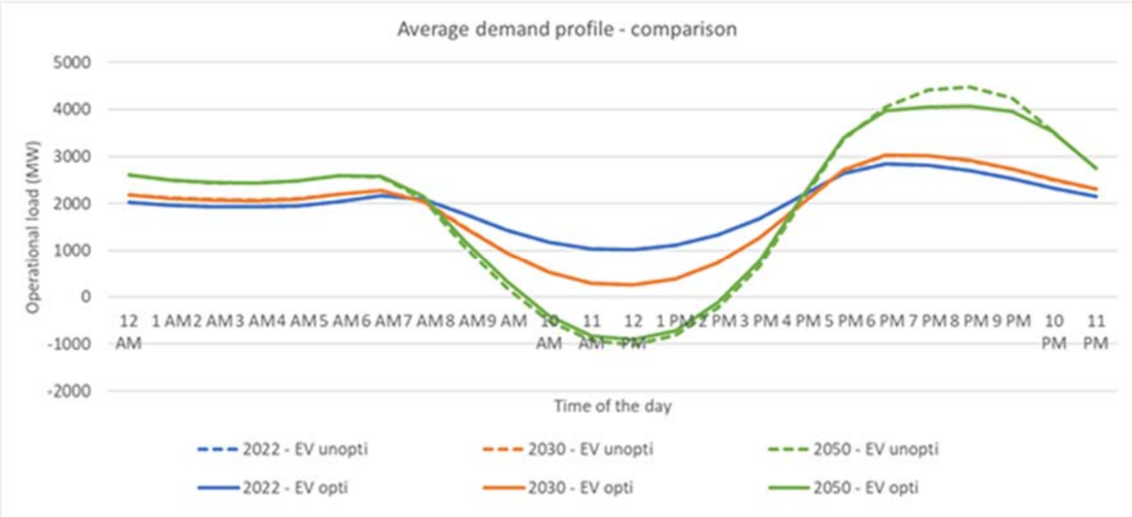
Because the modelling is focused on generation adequacy, the demand traces reflect operational demand before any measures to respond to low or negative operational demand. In these periods, storage and any other demand increase available in the market would be dispatched to soak up

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

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

Without EV optimisation, the 2050 demand profile would have a higher and sharper peak, as shown in Figure 28.

Figure 28: Average Demand Profile with and without Electric Vehicle Optimisation



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

B.3 Build and Retirement Scenarios

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

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

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

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

- Scenario 2 – All baseload retires by 2030:

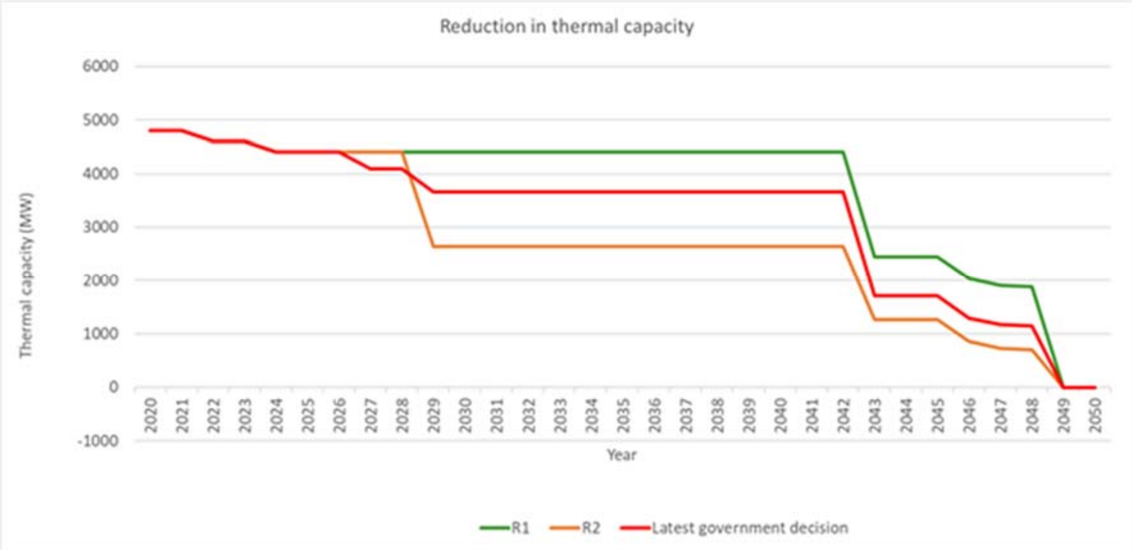
  In this scenario, there is a rapid decarbonization where all baseload generators (coal and CCGT) exit the market by 2030. Mid merit and peaking gas and liquid generation retire by 2050.

Table 3: Retirement scenarios

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

The modelling was conducted before the announcement of additional Synergy facility retirements by 2030.[34] The three retirement profiles are shown in Figure 29.

Figure 29: Retirement profiles



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

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

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

Table 4: Build scenarios

Scenarios	2022	2030	2050
S1	Current capacity mix	New capacity as required in line with respective 2050 targets	Sufficient PV + wind by 2050 to meet energy requirement Large storage capacity Some demand flexibility
S2			PV + Wind overbuild by 2050 reducing amount of storage required Less storage capacity Large demand flexibility

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

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

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

B.4 Timing of Expected Unserved Energy

Figure 30 through Figure 33 show the periods with highest likelihood of unserved energy in 2030 and 2050 under the 10% and 50% POE load forecasts.

Figure 30: LDC and Unserved Energy Events – 2030, 10% POE

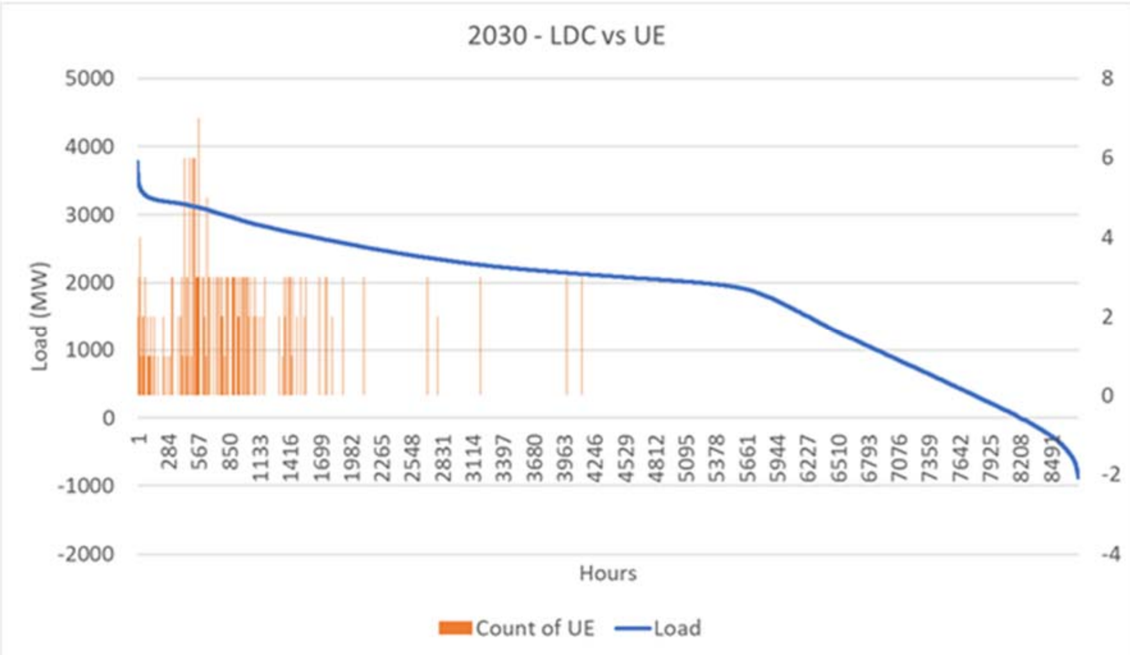


Figure 31: LDC and Unserved Energy Events – 2050, 10% POE

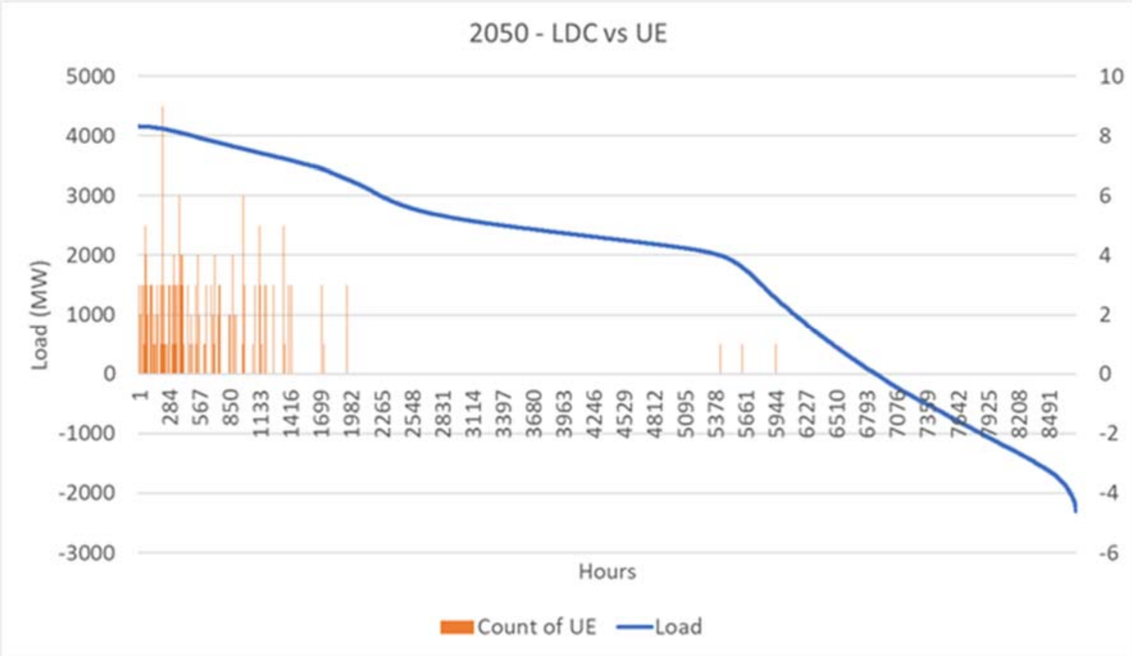


Figure 32: LDC and Unserved Energy Events – 2030, 50% POE

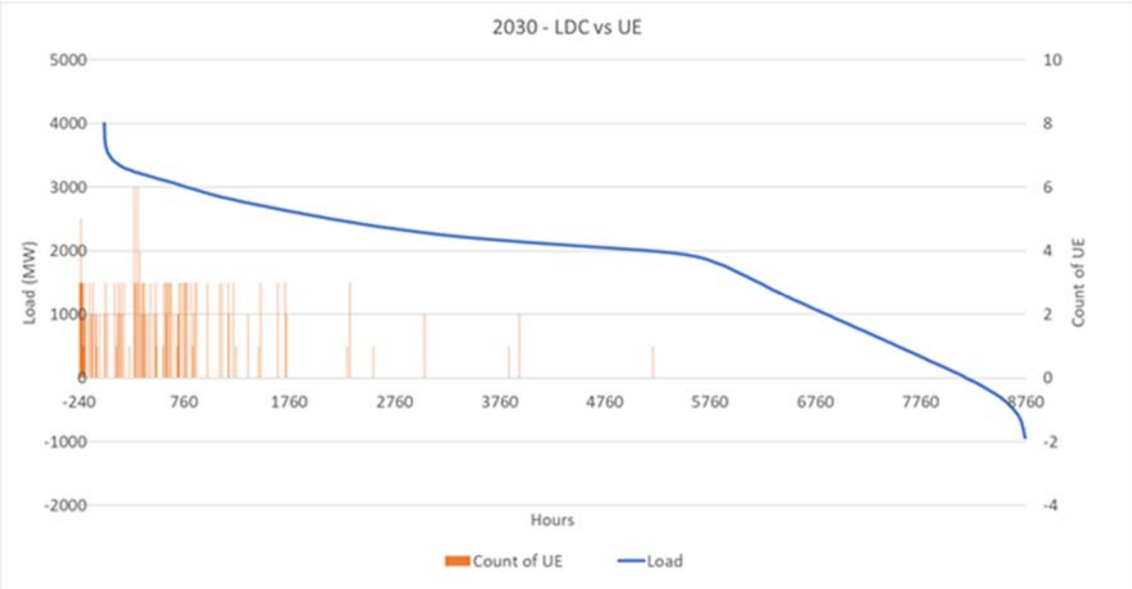
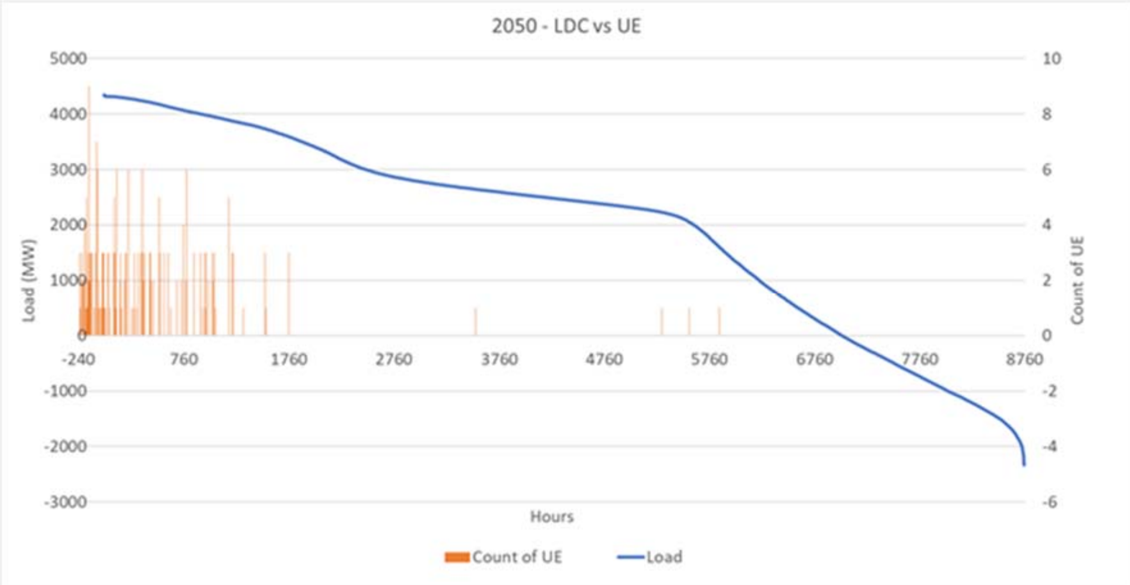


Figure 33: LDC and Unserved Energy Events – 2050, 50% POE



Appendix C. Estimated UCAP capacity

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

Table 5: Outage adjusted Capacity Credits

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

Facility	Forced Outage Rate 2012-2022 (FOR)	% Of hours in service	FOR/Service Hours (EFORd)	Nameplate Capacity	CC 2022/23	FOR Adjusted CC	EFORd Adjusted CC
PINJAR_GT11	1.30%	29.95%	4%	123.4	124	122.4	118.6
PINJAR_GT2	0.22%	2.34%	9%	37.4	30.5	30.4	27.7
PINJAR_GT3	0.43%	2.48%	17%	38.34	37	36.8	30.6
PINJAR_GT4	2.99%	4.41%	68%	38.34	37	35.9	11.9
PINJAR_GT5	0.35%	2.56%	14%	38.34	37	36.9	31.9
PINJAR_GT7	0.19%	2.85%	7%	38.34	37	36.9	34.6
PINJAR_GT9	1.47%	22.57%	6%	116.4	111	109.4	103.8
PRK_AG	0.79%	5.39%	15%	68	59.748	59.3	51.0
STHRNCRS_EG	9.27%	39.06%	24%	23	21.012	19.1	16.0
TESLA_GERALDTON_G1	0.05%	2.34%	2%	9.999	9.999	10.0	9.8
TESLA_KEMERTON_G1	0.00%	1.21%	0%	9.9	9.9	9.9	9.9
TESLA_NORTHAM_G1	0.08%	0.16%	51%	9.9	9.9	9.9	4.9
TESLA_PICTON_G1	0.13%	0.55%	24%	9.9	9.9	9.9	7.5
TIWEST_COG1	1.53%	88.71%	2%	42.1	36	35.4	35.4

Appendix D. Economic Modelling Results

D.1 Introduction

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

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

D.2 Methodology

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

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

The WEMSIM model includes:

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

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

- Government announcements regarding retirement of coal facilities;
- Retirement of remaining thermal facilities based on assumed technical lifetimes and an assumption that all carbon-emitting facilities will be retired by 2050; and
- Sufficient Wind, PV and BESS new build to keep unserved energy below an acceptable level.[35]

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

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

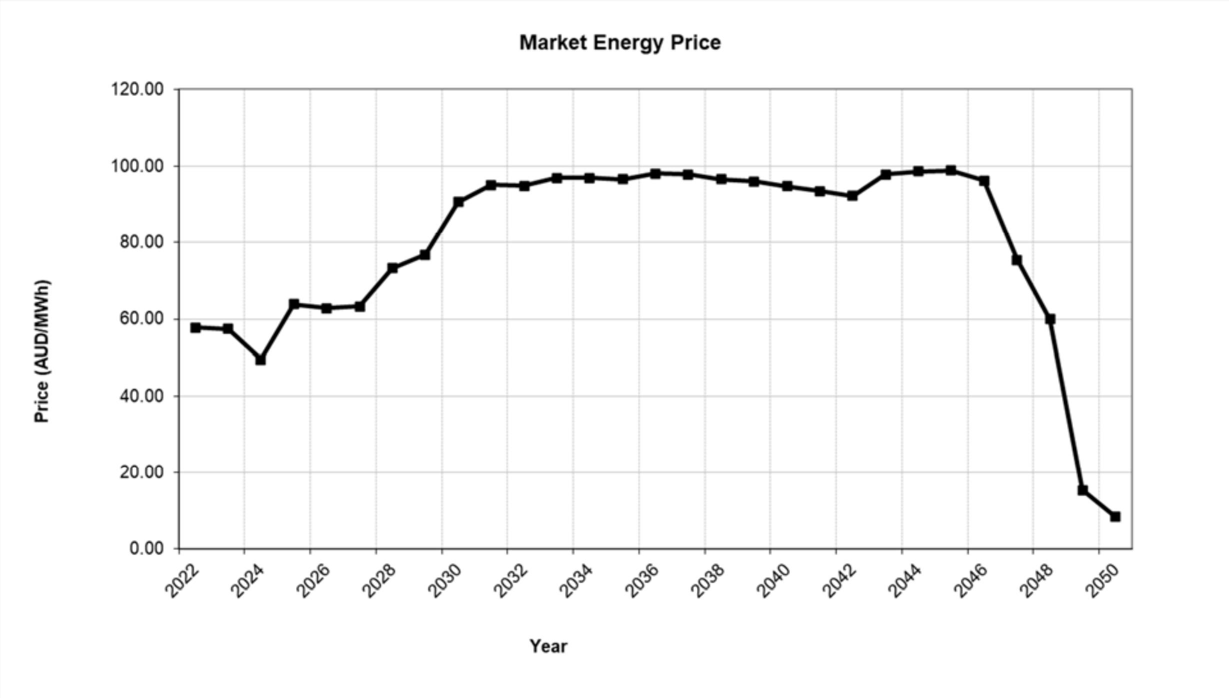
35 Ideally below the 0.002% reliability criterion, but since WEMSIM is not a Monte Carlo model, this is not exactly achieved.

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

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

D.3 Key Results

D.3.1 Market Energy Prices



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

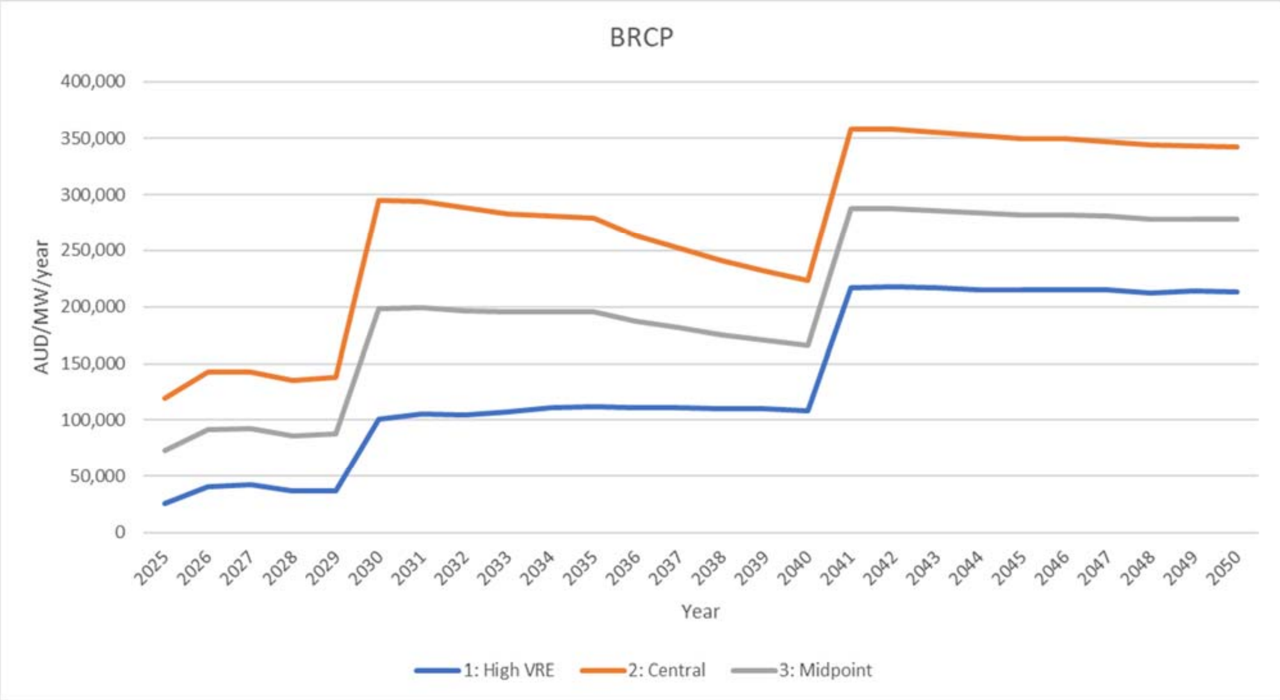
D.3.2 BRCP

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

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

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

- A large OCGT, up to 2025 (assumed as the last date that OCGT is an acceptable new build technology);
- A BESS, sized as follows:
  - o 4 hour from 2022-2029;
  - o 8 hour from 2030 to 2040; and
  - o 16 hour from 2041 to 2060.

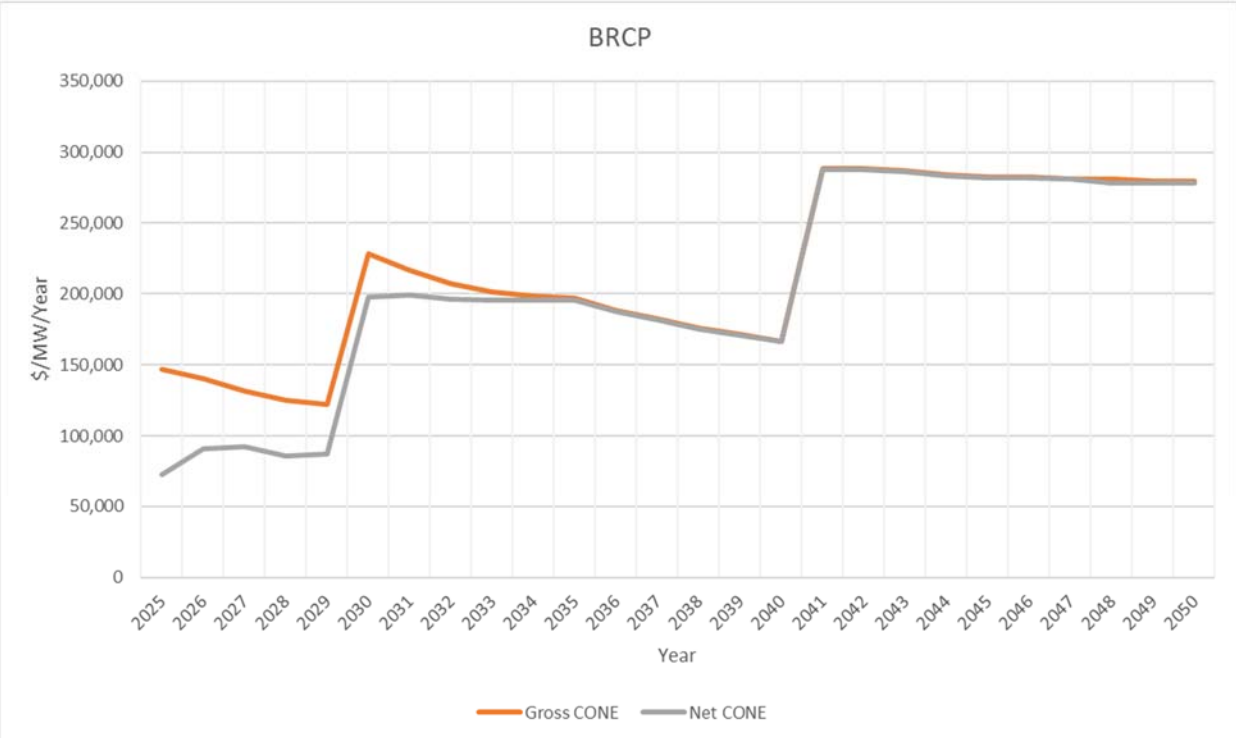


Key conclusions from these results are:

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

D.3.3 Net CONE vs Gross CONE

The following chart show the impact of using Net CONE vs Gross CONE (using the 'Midpoint' cost reduction outlook):



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

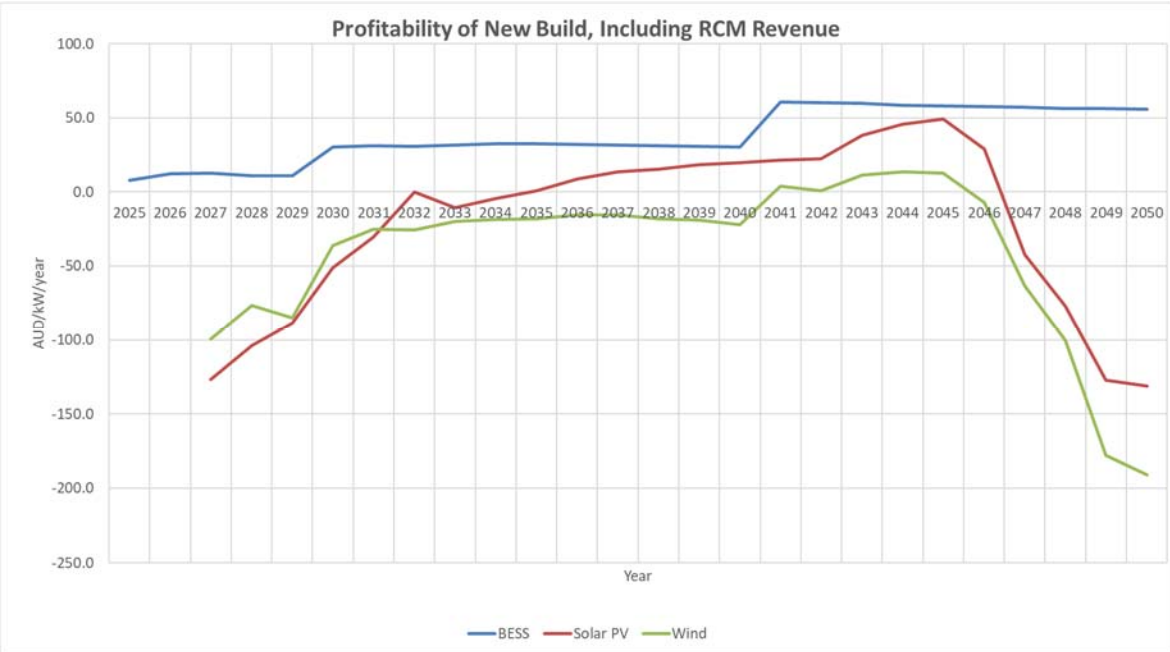
It should be noted that this result is very sensitive to new build assumptions: Increased intermittent generation build leads to greater utilisation and price spreads for BESS, increasing its net revenue and thus decreasing its Net CONE. Zero Net CONEs are possible under some realistic new build scenarios.

D.3.4 Profitability of New Build

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

The following results are based on the following settings:

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



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

The result could be adequate new build of BESS to perform the required load-shifting, but insufficient PV and wind capacity to provide the required energy. Several factors contribute to the low profitability of PV and wind:

- Using a Net CONE basis for the BRCP results in low BRCP values for the early years ; and
- The ELCC delta method allocates very low levels of capacity credits to wind and PV. Therefore, these technologies only receive a fraction of their CONE through the RCM. The ELCC values for PV are close to zero, as they cannot contribute to system peak load.

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