GOVERNMENT OF WESTERN AUSTRALIA

Department of Energy and Economic Diversification

Energy Policy WA

Capability Class 2 Technologies (CC2T) Review Working Group - Minutes

Date:	5 February 2026
Time:	9:30 AM – 11:30 AM
Location:	Microsoft Teams online

Attendees	Representing	Comment
Dora Guzeleva	Chair	
Jack Mitchell	Alinta Energy	Proxy for Oscar Carlberg
Brooke Edwards	AEMO	Proxy for Natalia Kostecki
Toby Price	AEMO	Proxy for Rebecca Pedlow-Collins
Neil Finney	BLT Energy	Proxy for Francis Ip
Jake Flynn	Collgar Renewables	
Alister Alford	Enel X	
Richard Cheng	ERA	Left 10:30am
Noel Schubert	Expert Consumer Panel	
Warren King	Frontier Energy	
Clement Ng	IGO	
Max Collins	Neoen	
Bobby Ditric	NewGen Power Kwinana	
Patrick Peake	Perth Energy	
Kaur Sumeet	Shell	Joined 10:22am
Rhiannon Bedola	Synergy	
Paul Jones	Western Power	
Other attendees	**From**	**Comment**
Leon Kwek	AEMO	Subject matter expert
Richard Bowmaker	Robinson Bowmaker Paul (RBP)	Consultant appointed to assist with this review
Sue Paul	RBP	
Eija Samson	RBP	
Catlianna Evans	RBP	
Shelley Worthington	EPWA	Secretariat

Sean McAvoy	EPWA	Secretariat
Luke Commins	EPWA	Secretariat
Apologies		
Rebecca Pedlow-Collins	AEMO	
Oscar Carlberg	Alinta	
Francis Ip	BLT Energy	
Dale Waterson	Merredin Energy	
Darren Gladman	SMA	
Kaavya Jha	Tesla Motors	

1. WELCOME

The Chair opened the meeting with an Acknowledgement of Country.

2. MEETING APOLOGIES AND ATTENDANCE

The Chair noted the attendance as listed above.

3. MINUTES OF MEETING 2025_12_04

The Chair noted that the minutes had been approved out of session and published online.

4. ACTION ITEMS

The Chair noted the update in the papers and invited AEMO to respond to Action Item 1/2025.

- Ms Edwards advised that:
  - AEMO has also observed an issue with the “spare” calculation and agrees that it can result in an unexpected representation of spare capacity.
  - the behaviour is not isolated to Electrical Storage Resources (ESRs) and would have existed pre-2023 reform. However, it has only become more noticeable with the growing participation of ESR.
  - spare capacity for scheduled and semi-scheduled facilities is included in the global spare capacity calculation for all training intervals, including periods where Reserve Capacity Obligation Quantity (RCOQ) may be zero under clause 4.26.1E of the Electricity System and Market (ESM) Rules.
  - AEMO has logged this issue in its ESM Issues Log.

The Chair advised that known issues in section 4.26 of the ESM Rules will be addressed in the future.

5. DSP AVAILABILITY OPTIONS

The Chair presented Slide 2 and handed over to Ms Paul.

Ms Paul presented Slides 4 and 5.

Ms Paul advised that in the international markets reviewed, Demand Side Programmes (DSPs) are not required to provide continuous curtailment for twelve hours. Analysis

shows that actual activation events typically last three to four hours. Therefore, it appears that the participant manages the risk.

In response to Mrs Bedola, Ms Paul clarified that Slide 5 was referring to lower Capacity Credits.

- Mr Ditric asked whether the frequency of activation in the other markets differs to the Wholesale Electricity Market (WEM).

Ms Paul responded that RBP analysed duration not frequency of activations. However, she noted it is likely difficult to compare frequency due to the factors of each market such as winter conditions in the United States.

- Mr Alford advised that comparisons with other markets must take account of differences in market design, as these differences make direct comparisons challenging. For example:
    - In the WEM, aggregation is limited to the Transmission Node Identifier (TNI) level, whereas other markets permit broader aggregation. This broader aggregation makes it easier for aggregators in those markets to deliver a consistent capacity response; and
    - In the PJM market, contribution is accessed under an Effective Load Carrying Capability (ELCC) method while other markets, like the WEM, measure contribution under another method.

The Chair thanked Mr Alford for noting concerns with comparisons.

- Mrs Bedola asked whether there was a comparison on how loads are encouraged to participate as a DSP rather than participating off market.

Ms Paul responded that cost recovery options to incentivise DSP participation was not part of the analysis.

Ms Paul presented Slide 7 – Demand-side integrated into the WEM through the DSP construct.

Ms Paul noted that certified DSPs will be registered based on electrical locations as the WEM does not allow for a DSP to register across multiple electrical locations.

- Noting that DSPs are based on a 50% Probability of Exceedance (PoE) curve and ESRs on a 10% PoE curve, Mr Schubert sought clarification as to whether the current market design is treating both resources as serving the same capacity function, rather than allowing each to respond to different parts of the demand curve.

The Chair explained that this subject was evaluated during the Reserve Capacity Mechanism (RCM) Review, which found that the 10% PoE for DSPs was not appropriate as it reduced the dispatch requirements. The Chair noted that the current concern is that the 23 hours obligation may be too low. However, if the 10% PoE is used rather than 50% PoE, it would likely create greater system issues with the reduced access to DSPs.

The Chair also explained that DSPs must be treated differently due to their limited availability throughout the year. Consequently, the usual practice is that DSPs are dispatched after ESRs.

- Mrs Bedola noted that:
    - The obligations for supplementary capacity (SC) are lower than those for DSPs, which may cause like-for-like comparisons challenging.

- The PoE curves are forecasts, therefore actual demand will likely differ.

Ms Paul presented Slides 8 to 11.

- Mrs Bedola:
  - explained that Project Jupiter is addressing objective 2. However, there are significant capability differences between Behind-the-Meter (BtM) storage and the curtailment of large industrial loads; and
  - asked how the mix of DSPs, SC and Non-co-optimised Essential System Services (NCESS) on 20 January 2025 came about.

The Chair clarified that significant reforms have been made to the WEM to improve the participation of DSPs. As recent SC and NCESS contracts have used BtM options, the aim is to encourage broader DSP participation instead of relying on emergency processes.

The Chair, with support from Mr Kwek, explained that the activation mix outcome on 20 January 2025 was due to some DSPs providing Contingency Reserve Raise services, leaving only 20 megawatts (MW) of DSP available for dispatch. Therefore, AEMO activated the remaining DSPs and sought other options through activating SC and NCESS to address the shortfall.

Ms Paul presented Slide 12 to 14. Ms Paul explained that the chart presented on slide 13 differs from the slide pack provided in advance, as RBP discovered that NCESS Contracts had accidently been double counted.

In response to Mrs Bedola, Ms Paul clarified that the chart on slide 14 is based on RCM settlement calculations and would therefore not include SC and NCESS.

- Mr Schubert suggested that objective 2 should also consider BtM commercial and industrial storage.
- Mrs Bedola suggested that an alternative DSP facility class is created for BtM storage rather than trying to make one class work for two different types of resources.

The Chair clarified that commercial and industrial storage is considered and will be increasingly useful in the future. Further, any changes to the DSP facility class will be considered by Project Jupiter and not through this review. However, significant reforms have been made to DSPs, and an effort must be made to include BtM storage.

- Regarding the chart on slide 14, Mrs Bedola asked whether winter occurrence was greater than summer due to the greater number of outages.
- Mr Schubert noted that generators do not schedule many planned outages in summer because it is a high demand period and ideally the risk of supply outages is evenly spread over the year to maximise maintenance planning.
- Mr Ditric noted that the previous winter was cloudy and cold which caused most generators, subject to outages, to be online to meet the demand and capture revenue. This explains why there is less capacity compared to summer.

Ms Paul explained that the chart shows about 120 intervals between 2021 and 2025 in which spare capacity was less than 750 MW. Of those, just under half occurred in winter with the rest spread across summer and the shoulder period.

The Chair confirmed that the WEM experiences a greater number of planned outages in winter compared to summer. However, the Chair also noted that scheduling outages has been problematic for several years, including because of the level of forced outages. While

AEMO must squeeze in all outages where it can, the system still needs the reserve margins to be available for the extreme peak events in summer.

The Chair explained the Reserve Capacity Target is based on the one-in-ten peak event, which happens in summer. However, the DSPs rules should be designed for the future, ensuring they are available in both summer and winter. The chart demonstrates that DSPs are not required between 8 am and 2pm, and so DSP obligations can change.

- Mr Ditric agreed that, if the Reserve Margin reflected increased DSP availability, then there may be improvements.

Ms Paul presented Slides 15 to 19 and sought comments from members on Option 1.

- Mr Ditric considered that BtM residential storage would be fully discharged and would not have the ability to re-charge by 6am.
- Mr Peake referenced the 2023 winter period that showed that there are long periods of significant overlap of low solar and low wind. Therefore, BtM storage would be required to charge from the grid.
- Mr Schubert expressed support for Option 1.
- Mr Cheng stated that he supported Option 1 relative to the other options.
- Mr Jones queried if there was merit in allowing BtM residential storage to opt-out of the morning obligation with a proportional discount to its Certified Reserve Capacity to support residential participation.
- Mrs Bedola considered that:
    - for BtM storage, particularly residential storage, the underlying load is dynamic across the day, which creates challenges to meet a set MW export value;
    - BtM storage used for SC and NCESS is not residential;
    - if residential storage is included, then electricity tariffs must be considered as Synergy and third-party aggregators are required to keep the customer whole, despite the cost if BtM storage is required to charge; and
    - Distributed Energy Resources (DER), DSP and residential storage each have their own challenges and is not the same as the curtailment of an industrial load which is more predictable.

The Chair stated that the aim is to facilitate industrial, commercial and some residential DSP participation. However, it may be more beneficial for residential BtM to be used for reducing a Market Participant's Individual Reserve Capacity Requirement (IRCR).

- Mrs Bedola noted that there are also challenges with IRCR reductions using BtM residential storage and that presents a different set of issues in terms of market equality and the setting of the Reserve Capacity Target.

The Chair agreed that the challenges will need to be overcome. However, other reforms have been made for IRCR reduction using BtM storage and it is up to Market Participants to decide whether there is more value in participating as a DSP.

The Chair further stated that aggregation should allow a Market Participant to meet the morning and evening obligation.

- Mr Alford noted that there are currently barriers preventing aggregators from achieving Option 1, primarily because aggregation is structured at the TNI level. In his experience, resource fatigue increases as the evening progresses, reducing the

availability of resources needed to meet evening obligations. Traditionally, this issue has been managed through over-subscription. However, TNI-level aggregation limits this and must be addressed to enable participation.

The Chair clarified that:

- Evidence shows that DSPs are exhausted by 8pm which leads to SC procurement that is also a detriment to aggregated DSP participation.
- Discussions with AEMO suggest that changing to a whole of system aggregation would reduce the DSPs value and may displace other resources.

- Mr Alford responded that the current TNI constraint increases Market Participant risk, which may reduce participation. This may be imposing higher overall costs on the system than the level of risk AEMO is seeking to manage.
- Mrs Bedola noted that, given the current high Benchmark Reserve Capacity Prices, DSPs should assume the risk, as customers are already paying too much and should not be exposed to additional risk.

The Chair stated that DSPs should accept some risk and it was up to AEMO to consider if the network constraints that determined the 2020 Taskforce decision should change. The Chair noted that to assist the aggregation some changes are suggested, and she recommended moving forward to slides 23 to 24.

Ms Paul presented Slides 23 to 24.

The Chair clarified that the option stating, “DSPs can subscribe as many loads as they want but can only associate those loads that will be activated during an event,” along with its associated bullet points on Slide 24, is no longer relevant and will therefore be removed.

- Mr Cheng questioned whether it was necessary to be prescriptive, or whether DSPs should be allowed to determine how they meet their requirements.

The Chair explained that the purpose of this was to provide flexibility with aggregation.

- Mr Schubert asked why the other loads would change their behaviour and increase demand during the period. He considered that it is more reasonable to assume these loads would operate as normal, meaning a net MW reduction would still occur. The key is how performance is measured.

Ms Paul answered that the settlement calculation, which will include non-activated loads, will underestimate the DSP response.

The Chair explained that another issue is that, due to the period in which DSPs can specify the loads that will be activated, it is possible for DSPs to manipulate their baseline by excluding loads that cannot perform.

- Mrs Bedola noted concerns that DSPs could game the system by changing load behaviour in the weeks prior to activation.

The Chair agreed but clarified that the focus is on when the baseline is calculated, i.e. 10 days before activation.

- Mr Alford did not oppose the proposal. However, he noted that the change is likely to have only a minimal impact on DSPs, as it would mainly affect those with small residential or commercial storage in a TNI area. He therefore questioned whether efforts should instead focus on other measures that would encourage broader DSP participation.

The Chair stated that the aim was to provide aggregators with the ability to determine how best to use their DSP portfolio to achieve the morning and evening windows. They can select loads for the morning and use others for the evening window.

Ms Paul presented Slide 20 and asked for comments on Option 2.

- Mrs Bedola noted that BtM storage would require duration grandfathering as it was unlikely that the installed storage resources can meet new duration requirements.

The Chair agreed and noted that under Option 2, DSP obligations would always increase as the ESR Obligation Duration (ESROD) increases.

Ms Paul presented Slide 21 and asked for comments on Option 3.

- Mrs Bedola sought to clarify how the intervals are chosen and whether this was as prescriptive as advising that “on 2 January the DSP must be available from 3pm to 9pm”.

Ms Paul explained that, due to this being a forecast, it would be a window of time during which the DSP would likely be activated identified through AEMO’s modelling. This approach is similar to that taken by the Independent System Operator (ISO) of New England, with windows changing based on the season.

Ms Paul presented Slides 22 and asked for comments on the evaluation.

- Mr Price suggested a change to Option 1 in which, similar to how AEMO sets a mid-peak ESR Obligation Interval, AEMO would set a mid-DSP Obligation Interval based on its modelling of when DSPs are required.
- Mr Ditric questioned whether it was appropriate to set fixed periods for DSPs, as the optimal timing for DSPs may change as the system evolves.

The Chair agreed that dynamic DSP obligations should be considered.

- Mrs Bedola queried why Option 2 was not evaluated higher as the ESROD would consider Power System Security and Reliability (PSSR) requirements and therefore identify when DSPs are required.

The Chair explained that Option 2 would decrease the availability of DSP, while Option 1 retains the current availability. She noted that problems start to occur as obligation intervals decrease and the current analysis suggests that the morning is becoming an issue.

- Mrs Bedola noted that DSPs are treated as a last resort and, therefore, if the morning is becoming an issue for PSSR then other options, like ESR, should be considered.
- Mr Price noted that, as the morning becomes more of an issue, it warranted consideration about the volume of storage on the system.
- Mr Schubert noted that there should be a clear understanding of how DSP, ESR and other resources interact to ensure any recommendations address what is best for the system.

The Chair explained that the review is still examining whether the ESR obligations need to be revised. There are concerns that during periods of low renewable generation, ESR resources could become depleted. Consequently, DSPs would be required during these events. Treating DSPs in the same way as storage could create additional issues, as DSPs have different limitations.

Ms Paul advised that the ongoing future state analysis should pick up when ESR is required to avoid unserved energy.

In responses to a question from Mrs Bedola, the Chair suggested that perhaps Options 1 and 2 could converge and this will be considered.

6. CURRENT ANALYSIS

Mr Bowmaker presented slides 27 to 38.

- Mr Price asked if the period in this analysis aligned with the chart on slide 14 regarding the occurrence of spare capacity of less than 750 MW.

Mr Bowmaker replied that this analysis did not show any results for the morning period, but otherwise it aligned.

Mr Bowmaker presented slides 39 to 43.

- Mr Schubert recommended that on capacity-critical days, ESRs should have a mandatory minimum charge before the likely stress period.
- Mrs Bedola queried if there was any value in further analysis noting that AEMO has already implemented minimum state of charge conditions.

The Chair clarified that AEMO's approach is only transitional for the 2025–26 Hot Season. The aim is to establish clear conditions for when AEMO can activate minimum state-of-charge requirements and minimise the risks that AEMO must rely on discretionary judgement.

7. GENERAL BUSINESS

The Chair thanked members for their contributions and closed the meeting.

The meeting closed at 11:30am.