Meeting Agenda

Meeting Title:	Cost Allocation Review Working Group (**CARWG**)
Meeting Number:	2023_03_21
Date:	Tuesday 21 March 2023
Time:	1:00pm to 2:30pm
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 2022_11_29	Chair	Decision	2 min
4	Action Items	Chair	Noting	2 min
5	Timeline and purpose	Marsden Jacob	Discussion	2 min
6	Feedback from consultation process and potential refinements of methods **(a)** Frequency Regulation – WEM Deviation Method **(b)** Contingency Reserve Raise – Treatment of Multiple Dispatchable Units under the Runway Method **(c)** Contingency Reserve Lower – Potential Changes to the Proposed Allocation Methodology **(d)** Market Fees – BESS Cost Recovery	Marsden Jacob	Discussion	70 min
7	Next Steps	Chair	Noting	5 min
8	General Business	Chair	Discussion	5 min
	Next Meeting: TBD			

Please note this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the Cost Allocation Review Working Group (**Members**) note their obligations under the *Competition and Consumer Act 2010* (**CCA**).

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

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

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

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

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

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

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

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

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

Sensitive Information means and includes:

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

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

Guiding Principle – what not to discuss

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

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

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

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

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

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

Compliance Procedures for Meetings

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

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

Minutes

Meeting Title:	Cost Allocation Review Working Group (**CARWG**)
Date:	29 November 2022
Time:	1:00pm – 2:15pm
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Oscar Carlberg	Alinta Energy	
Daniel Kurz	Summit Southern Cross Power	
Rebecca White	Collgar Wind Farm	
Noel Schubert	Small-Use Consumer Representative	
Mark McKinnon	Western Power	
Justin Ashley	Synergy	Proxy for Jason Froud
Huoy Wei Tang	Synergy	Observer
Genevieve Teo	Synergy	
Paul Arias	Shell Energy	
Mena Gilchrist	Australian Energy Market Operator (**AEMO**)	
Tom Frood	Bright Energy	
Jacinta Key	Woodside	Proxy for Cameron Parrotte
Grant Draper	Marsden Jacob Associates (**MJA**)	Presenter
Peter McKenzie	MJA	Presenter
Toby Price	AEMO	Observer
Matthew Fairclough	AEMO	Observer
Stephen Eliot	Energy Policy WA (**EPWA**)	
Shelley Worthington	EPWA	

Apologies	From	Comment
Jason Froud	Synergy	

Cameron Parrotte	Woodside	
Daniel Kurz	Summit Southern Cross Power	

Item	Subject	Action
1	**Welcome and Agenda** The Chair opened the meeting at 1:00pm.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above. The Chair noted the competition law obligations of CARWG members.	
3	**Minutes of CARWG Meeting 2022_09_27 and 2022_10_25** Draft minutes of the CARWG meeting held on 27 September and 25 October 2022 were accepted and approved.	
4	**Action Items** The Chair noted the following comments on the action items: Item 8: AEMO would work with EPWA to provide a breakdown of costs once the model was confirmed. Item 10: AEMO does not collect the information on a breakdown of market fees, the statement that market generators incur most of the fees was made in recognition that a lot of AEMO's systems are developed for generators.	
5	**Options for Allocating Frequency Regulation Costs** Mr Draper noted MJA was in the process of finalising the options that will be explored in the consultation paper, as follows: • current National Energy Market (**NEM**) Causer-Pays • new NEM Causer-Pays • existing Wholesale Energy Market (**WEM**) allocation • Tolerance Method (referred to as the Forecast Range method) Mr Draper also noted that he was looking to close off on the preferred method for Frequency Regulation and Contingency Reserve Lower as a result of today's meeting. Mr Draper noted that on 15 November 2022 the MAC endorsed further consideration of the Forecast Range method that could be implemented as an interim method, with a move to consideration of a more complex method, such as the new NEM Causer-Pays method, at a later stage. AEMO and EPWA met 17 November 2022 to discuss the Forecast Range method to further understand how it would work, including any benefits or potential implementation issues that may be involved. Mr Draper provided a recap of the Tolerance Method noting that it: • provides additional input to AEMO for establishing the Regulation quantity that needs to be procured in a Trading Interval; • provides a Causer-Pays methodology for recovering Regulation costs; and • helps identify the "firm" capability of Intermittent Facilities to calculate reserves available for Frequency Control Essential System Services (**FCESS**)	

Item	Subject	Action
	Mr Draper provided an example of a situation that was described in the consultation paper, of an Intermittent Facility i.e. a wind or solar farm deliberately under generating (below its capability) and therefore able to provide those services by being able to ramp up and provide a Raise service if required. He noted that in the future, if wind and solar were both on and solar drives the prices down, wind could come off and provide the Raise service. He also noted, however, there was a question of whether, in that instance, the incentive was provided from the Essential System Services (**ESS**) market or the negative pricing in the energy market. Mr Draped noted AEMO's concern with volatility, and that AEMO will procure these services dynamically in the future and would require more information than what it has required in the past. If AEMO was able to calibrate that requirement based on a Facilities own uncertainty, that appeared to be a good way of establishing Regulation requirements. Mr Draper noted that there were potential benefits with the method that AEMO is proposing, in that it helps set the Regulation quantity and is closer to a Causer-Pays methodology for the recovery of Frequency Regulation costs. Mr Draper noted that MJA analysed what the level of cost recovery from different technologies would be under this method and compared it with the current NEM Causer-Pays and the new NEM Causer-Pays. He noted d that intermittent generators were bearing the higher proportion of the recovery of Regulation costs. Mr Draper noted the potential issues with the Forecast Range Method including: • that Market Participants could be incentivised to under-forecast to minimise allocation of Frequency Regulation costs; • to mitigate this, the requirement to implement a penalty regime if actual output exceeds Forecast Range; and • the potential for Market Participants to influence market outcomes in their favour. Mr Draper noted that, as a consequence, there may be a need for a set of rules to prevent gaming behaviour. Mr Draper noted that many of the Frequency Regulation cost recovery options the CARWG has looked at provided for more than just cost recovery. For example, the NEM Causer-Pays provided financial compensation for Market Participants that help minimize frequency deviations and the Forecast Range incentivises participants to improve their forecasting. He also noted that the WEM has a different framework from the NEM with quite an extensive regime to maintain system frequency already in place. Mr Draper noted that the aim was to try to provide some incentives for generators to operate within the Tolerance Bands, but that the implementation costs may be quite significant, especially for intermittent generation. • Mr Schubert noted that what was lacking in the WEM were incentives for fast acting renewables to help with Frequency Regulation. He	

Item	Subject	Action
	considered that more generators helping with Frequency Regulation and contingency response (making it more competitive) would likely result in lower costs for consumers in the long term, provided that the mechanisms do not cost more to implement than the benefits. • Mr Price noted with regard to Mr Schubert's comment that the new Frequency Co-optimized Essential System Services (**FCESS**) are provider agnostic and there are constructs in the rules to allow both semi-scheduled and scheduled Facilities to provide FCESS. AEMO has tried to keep the enablement processes for those services as agnostic to provider as possible. Therefore, there should be no barriers to Intermittent Facilities who are capable i.e. able to provide controlled Raise and Lower services, whether that be Regulation or Contingency Reserve, to be able to provide those services in the new market. AEMO was very hopeful that some proponents would accredit their Intermittent Facilities to provide those services and Mr Price agreed that the method needs to be considered in terms of its benefits versus cost of implementation. Mr Draper noted that Mr Price's point was interesting in that these issues can be addressed on the supply side, such as creating the Essential Systems Services market so intermittent facilities can participate in ESS, or on the demand side by getting those that are causing the problem to minimise it. Ms Guzeleva added that at the end of the day the issues can be tackled from both sides, and noted that with the move to a new market for those services the rules should provide the right incentives for the most efficient set of services to be provided. Ms Guzeleva reminded the CARWG that the aim was for a fair, equitable, efficient distribution of the market costs of the provision of those services. • Mr Frood asked if primary frequency response obligations were different in the NEM. • Ms Guzeleva noted that this was discussed at the 25 October CARWG meeting and was captured in the minutes of that meeting She recapped that, while there is a slight difference in the primary frequency response or the Droop settings that are required in the NEM and the WEM, both market arrangements do require primary frequency response from generators. • Mr Schubert noted many of generators in the NEM seem to be on AGC while there were not many in the WEM on AGC. • Ms Guzeleva noted that she believed they all will be required to be on AGC in the future, if they are accredited to provide regulation. • Mr Price noted that he believed AGC was still optional if a generator can respond to a dispatch instruction by some other means, but that providers of Regulation need to be on AGC. • Ms Guzeleva summarised that the arrangement in the WEM and the NEM are similar, but that the WEM currently has a handful of providers versus the many providers of frequency response in the NEM, making the market a lot more competitive there.	

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	<u>WEM Deviation Method</u> Mr Draper noted that the proposed alternative method, the WEM Deviation Method (slide 18) was based, to a large extent, on the method that AEMO proposed, but that it had just a single purpose. If the fundamental problem is variability of output, rather than accuracy of forecasting, this proposed method would: (i) estimate the standard deviations from the average generation across a 30 minute Trading Interval; (ii) normalize it; (iii) calculate a contribution factor for each Trading Interval; and (iv) apportion the Frequency Reregulation costs to each generation or load on that basis. Mr Draper noted that, while this alternative method was not that different from AEMO's Forecast Range, it would set a target and estimate deviations from that target. However, this alternative method would not try to meet other objectives, i.e. to improve forecasting or to set regulation quantities. Mr Draper provided examples of the pros and cons of the WEM Deviation Method (slide 19) and noted that, in terms of cost recovery, this method was closer to the new NEM method and the existing WEM cost allocation to wind and solar facilities. Mr Draper noted that the current proposal for the WEM was to either use the WEM Deviation Method as an interim method or to retain the current method. • Mr Price asked Mr Draper if he could confirm that this alternative method was measuring deviations from a dispatch target. Mr McKenzie provided an overview of the method and Ms Guzeleva clarified that deviations are not measured against a dispatch target, but from a straight line between point A and point B over period. • Mr Price noted that this made sense for how the Causer-Pays could be applied to historical data in the WEM. However, if you were to use point A and point B rather than point A being the start of an interval and point B being a dispatch target then if point B happens to be nowhere near what a participant said that they were going to do, queried what this would do in terms of the regulation requirements. Ms Guzeleva noted that currently there was no concept of dispatch targets for the intermittent facilities and there would need to be a change in the rules to introduce the concept of dispatch targets for semi-scheduled and non-scheduled Facilities. What we were looking to incentivize is to reduce their volatility. Mr Draper noted that the proposed alternative method did have limitations. Rather than establishing ranges or targets, the method was just looking at deviations as a proxy for measuring variability. Ms Guzeleva acknowledged that the method was not perfect and that it was only focused on cost allocation on the basis of volatility of output or consumption. However, this was designed as a starting point with the expectation that a more sophisticated/appropriate method would be implemented at some point in the future.	

Item	Subject	Action
	• Mr Schubert, asked if there was serious concern with the current WEM method or was it possible to wait until the new market starts in October 2023 to see how that goes and then decide whether something else was required. • Mr Draper responded that this was a possibility. • Ms Guzeleva noted that there was a strong view expressed by AEMO in the, Renewable Energy Integration – SWIS Update paper, published September 2021, that something needs to be done and there was a strong desire to start sending price signals to incentivize generators to reduce their volatility. • Mr Schubert noted that Mr Price was saying that from October 2023, that there could be better response from the intermittent generators and we may be in a better position to decide whether to change the current method after seeing how the market operates for the first year. Ms Guzeleva noted that there were two different things, what the market provides and how we distribute the cost of it, and that this exercise is only about the cost distribution and not about trying to incentivize a provision of a service, which the new ESS market should do. • Mr Schubert noted that if there are serious concerns about distributing the costs (in 2023/2024) there would be a need for another method for allocating the costs but that after the new market start, if the concerns are not as strong then perhaps there was no need to do anything now. Ms Guzeleva noted that this was true but that if we decided to wait then this probably should wait for the new NEM method to be bedded down. Mr Carlberg noted that, in deciding whether to provide his support, he would like consideration of: • how much ESS cost would be saved; • the difference compared to the status quo in terms of payments by intermittent generators; and • the impact on the business case for renewables. Ms Guzeleva noted her concern that the CARWG was confusing who provides the service in the market with who causes the problem. Ms Guzeleva added that before a final decision was made a cost benefit analysis was needed. Mr Draper asked if the WEM Deviation method was worth considering as a realistic option to be implemented after new market start in 2023, to use as an interim method before the new NEM Causer-Pays method has been implemented. Ms Guzeleva noted that a decision on implementing the new NEM method may be premature, because in 2025 it may still be considered that this is a very complex and expensive method for the WEM to implement. She added that there are risks associated with doing nothing in the interim, or implementing something that is expensive that needs to be changed. Ms Guzeleva noted that this was the reason for trying to simplify an interim method, and that currently there is no signal that says - if you reduce your volatility you will save money.	

Item	Subject	Action
	Mr Draper noted that the WEM Deviation method was simplified for cost allocation purposes, but it is easier to calculate while providing signals to reduce volatility, as it results in a higher cost allocation to intermittent plant. In terms of the split between customers and generators, it is still around 50%/50% using this method, almost half of the generation costs assigned to intermittent generation. • Mr Schubert noted that he would like to see incentives for more participants providing the regulation service so that there is more competition and lower costs so that costs are lowered for consumers. • Mr Draper noted that was consideration for the supply side and asked if Mr Schubert wanted greater participation of intermittents in the formal ESS mechanisms. • Mr Schubert responded that he would like to see the demand side participating too, competing with the supply side to provide the services. • Mr Price reiterated AEMO's view that a Regulation Causer-Pays framework beyond what is currently in place is pretty essential moving forward, given the massive increases that AEMO is seeing in volatility on the system and the challenges in meeting that. It was really important to have incentives on both sides to both mitigate the problem by providing the service and providing incentives to reduce volatility and reduce the need for the service. Mr Price acknowledged Carlberg's point but noted that it is not necessarily the role of Causer-Pays to avoid charging for behaviour that adds to the cost of managing the system and that if that challenges the financial case of renewables, then there are other places where that should be dealt with. • Ms Gilchrist sought clarification on intended implementation dates. • Mr Draper noted that it is not proposed to implement the WEM Deviation method until after the new market start in October 2023. Mr Draper noted that the aim is to get to the point where MJA could evaluate a method and develop a business case rather than trying to do the business case on all four options that have been presented to the group. Ms Guzeleva noted the issue the Mr Price refers to was in the AEMO paper (as mentioned previously) and was one of the essential urgent actions AEMO was calling for, i.e. a price signal to be sent, to reduce volatility on the system and therefore reduce the need for and the cost of the service.	
	Contingency Reserve Lower – Runway Method Mr Draper provided further clarification of how the method would work. Mr Draper covered the requirement for Contingency Reserve Lower, noting that the introduction of large scale battery energy storage systems (**BESS**) had the potential to increase the largest single Load risk on the system and as a result the requirement for this service. Mr Draper provided an overview of the proposed Runway Method for Contingency Reserve Lower, noting that the analysis was done for different scenarios	

Item	Subject	Action
	looking at multiple batteries and how the cost increase would be attributed. Mr Draper noted that this cost attribution to large scale batteries was to provide some incentives for them to split across a number of circuits. • Mr Schubert noted that rooftop photovoltaic (**PV**) is likely to have high output when all the large battery is charging in the middle of the day. He asked AEMO to comment on whether, the fact that to comply with AS4777 rooftop PV is likely to reduce its output automatically when the frequency gets to a certain point, might mean that this need for Contingency Reserve Lower is not as critical. Mr Schubert did not consider the loss of large Loads to be as serious when there is lots of rooftop PV output. • Mr Price noted that this was a good point and that one of the benefits of the new framework for FCESS is that AEMO can set more dynamically the quantities required. Mr Price noted that they can be reflective of the system conditions at the time and that there will be opportunities that will be made clear in the FCESS quantity procedure (when that goes out for consultation). He added that this will reflect what AEMO will take into account when setting those quantities, one of those being the Causer-Pays angle. • Mr Carlberg asked whether it is likely that a transmission line with a load higher than the size of the battery may be setting the Contingency Lower requirement instead of the battery. • Mr Price noted that anything over 120MW would set the requirement given that there were no block Loads larger than that, and that he was fairly sure that there were currently no transmission lines with a Load risk of that order of magnitude. Mr Draper noted that Mr Schubert had made the point previously that, in terms of transmission design, Western Power would not be increasing the risk through augmentation of the system. • Mr Schubert noted that he did not know what the largest Load was on a transmission line, but that they had talked about the Goldfields line at 120 MW causing the requirement. • Mr McKinnon noted his understanding that in the Eastern Goldfields even the largest mine site was in that 120 MW order of magnitude. • Ms Guzeleva noted that the concern was not the current largest Load, but the size of the storage (which is necessary) coming on the system in the future. • Mr Fairclough agreed with Ms Guzeleva, noting that the largest battery will set a requirement higher than the current largest Load. Mr Draper noted the Consultation would be recommending that the runway method be applied to large Loads that exceed that 120 MW threshold so that they are attributed more of the costs and incentivised to configure differently.	

Item	Subject	Action
	Ms Guzeleva noted the implementation timeframes needs to be properly aligned with other activities because AEMO must prioritise implementing its market systems for 1 October 2023.	
7	**Next Steps** Next steps: EPWA finalising the CAR Consultation Paper for the next MAC meeting scheduled for 13 December 2022.	
8	**General Business** No general business was discussed. The date for the next CARWG meeting is to be determined	

The meeting closed at 2:15pm.

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

Agenda Item 4: CARWG Action Items

Cost Allocation Review Working Group (**CARWG**) Meeting 2023_03_21

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

Item	Action	Responsibility	Meeting Arising	Status
9	AEMO is to consider what information can be provided to assist the CARWG in understanding the current breakdown of its expenses by market segment.	AEMO	2022_09_27	**Closed** AEMO advised at the CARWG meeting on 29/11/2023 that it does not collect he information on the breakdown of market fees by market segment.
10	AEMO is to provide a broad estimate of its costs to implement the WEM Hybrid Method.	AEMO	2022_09_27	**Closed** The WEM Hybrid Method is no longer being considered for allocating Market Fees, so AEMO will not be asked to provide a costs estimate for this method.

Government of **Western Australia**
Energy Policy WA

Cost Allocation Review: Consultation Feedback and Potential Refinement of Methods

Presentation to the Cost Allocation Review Working Group (CARWG)

21 March 2023

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

Agenda

5. Timeline and Purpose

Timeline

Steps/Tasks	Duration/Timing
Step 1 – Policy Assessments	
(a) Literature review of the methodologies to allocate Market Fees and ESS costs in other jurisdictions	Mid-April to Mid-May 2022
(b) In consultation with the MAC Working Group, assess whether, and to what extent, the current allocation method for the Market Fees and for the costs for each of the ESS are aligned with the causer-pays principle and, if not, whether they should be	Mid-May to Mid-June 2022
Step 2 – Practicability Assessments	
In consultation with the MAC Working Group, for the fees and costs that are not aligned, or not fully aligned, with causer-pays principle: • Identify the options that can be practically and efficiently applied in the WEM to allocate the Market Fees and each ESS cost • Assess each option against the guiding principles • Model the impact of each of the options on Market Participants • Recommend a preferred option for the allocation of the Market Fees and each ESS cost	July-September 2022
Step 3 – Methodology Development	
Develop the details of the cost allocation methodologies in consultation with the MAC Working Group	September-October 2022
Develop and publish a consultation paper on the design for the allocation methodologies and seek stakeholder comments	November-January 2023
Develop publish an information paper on the detailed design for the allocation methodologies	March 2023
Step 4 – Formal Rule Change	
Develop one or more Rule Change Proposals for consideration by MAC, and approval by the Coordinator and Minister	April 2023

Purpose

Incorporating feedback from the public consultation process into the detailed design of the proposed cost allocation methods

6. Feedback from Consultation Process and Potential Refinements of Methods

6(a) Frequency Regulation – WEM Deviation Method

Response to Participant Feedback

Proposal (2)(a) Adopt the WEM deviation Method to allocate Frequency Regulation costs in 2024/25		
Participant	**Issues Raised**	**Response and Potential Solutions**
AEMO	• Proposed method ignores forecasts for sent out generation from Semi-Scheduled Facilities and instead apportions costs based on deviations from a hypothetical linear dispatch target. • As a result, there is no incentive for Semi-Scheduled Facilities to meet their expected output, only to maintain linear ramp to avoid Regulation costs. • Where actual output deviates from expected output and a Semi-Scheduled Facility maintains a linear ramp, the Regulation service to meet the deviation would be distributed to other Facilities. • Fails to provide incentives to minimise to both volatility and forecasting accuracy. • Recommends that forecasts be determined ex-ante.	• Can use Semi-Scheduled Facilities Balancing Submission forecasts (typically have a single forecast for each trading interval) to determine the hypothetical linear dispatch target. • Semi-Scheduled Facilities then held accountable to minimise deviations around the linear dispatch target in each Trading Interval and are held accountable for accurate forecasts.
Alinta Energy	• Concerned that the WEM Deviation Method and the new NEM Causer Pays Method will both impose additional costs on large-scale renewable generators, not address behind the meter PV customers contribution to frequency deviations, or deliver substantial benefits. • Propose re-considering the current NEM forecasting method (AEMO responsible for central forecasting of intermittent generation with generators having the option to provide forecasts) because this may improve the forecast accuracy and minimise regulation requirements without imposing additional costs and may improve consistency (but note that Market Participants may not improve forecasting if their contracts allow them to pass through these costs).	• The purpose of the WEM Deviation Method is to allocate costs to the facilities that cause frequency deviations because of deviations in their output. It is anticipated that Semi-Scheduled Facilities will be a significant contributor to these frequency deviations and should be allocated a higher proportion of the costs. • Around 50% of Frequency Regulation costs are allocated to loads (via retailers and aggregators). If they have customers with PV in their retail portfolio that cause significant deviations in output, then retailers can pass these costs through to these customers. Cost allocation to retail customers is out of scope for this review, only the allocation of Frequency Regulation costs to Market Participants.

Response to Participant Feedback

Proposal (2)(a) Adopt the WEM deviation Method to allocate Frequency Regulation costs in 2024/25		
Participant	**Issues Raised**	**Response and Potential Solutions**
Australian Energy Council	• Avoid any approach that will impose additional costs on renewable projects. • Payments from large-scale renewable projects should be proportional to the regulation costs they cause and those caused by rooftop PV.	• See the feedback on Alinta Energy's comments.
Perth Energy	• Supports the WEM Deviation Method.	
Shell Energy	• Supports the WEM Deviation Method.	
Synergy	• Further investigation of the WEM Deviation Method and the new NEM Causer-Pays Method is required and there would be cost savings from implementing one method rather than implementing one and later replacing it with the other. • Incentives are needed for normal loads (not aggregators) to operate behind the meter batteries in a way to minimise load variation – this will need to be done by regulated tariffs. • Query whether using a linear dispatch target is appropriate for modelling, as ramping is not typically linear, and whether there are different targets for each 5-minute dispatch interval. • Loads may not be able to be incentivised to minimise deviations in generation because they are subject to regulated tariffs, and note the complexity involved with explaining this mechanism to retail customers.	• Agree that the focus of this review is allocation of Frequency Regulation costs to Market Participants (not retail customers) to provide incentives to minimise generation and load deviations and reduce Frequency Regulation costs. Incentives for improving behaviour of retail customers to reduce wholesale costs is out of scope for the Cost Allocation Review. • Measuring deviations from a linear dispatch target over either 5 or 30 minutes is a standard approach in the NEM.

Options for Refining WEM Deviation Method

- Options for developing contribution factors :
  - Option 1: Measure deviations from a linear dispatch targets over 30 minute Trading Intervals (not average of deviations from linear dispatch targets over 5 minute intervals for each 30 minute period as done previously)
  - Option 2: Use Balancing Market submissions for Semi-Scheduled Generation as the forecast for start and end points for each 30 minute period and measure deviations from a linear dispatch target

Refining the WEM Deviation Method		
Change the method to use 30 minute targets	Assign targets for renewable generators from balancing submissions	Recalculate contribution factors

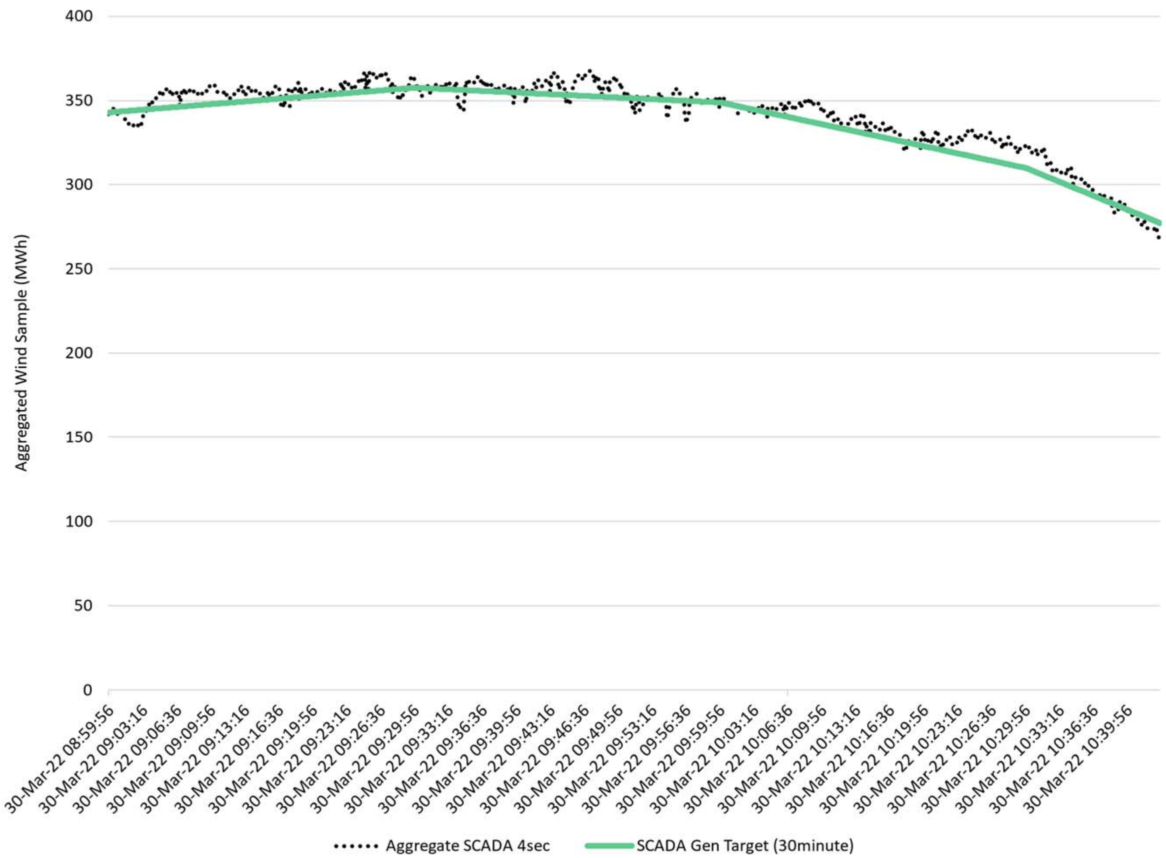
WEM Deviation Method Options

The WEM Deviation Method can use two sources to set the 30 minute dispatch targets – Balancing Market forecasts or SCADA. Both methods have pros and cons.

	Option 1: Balancing Market Submission Method	Option 2: SCADA Submission Method
Pros	• The forecasts submitted to Balancing Market as targets for generation is given ahead of the dispatch period	• SCADA data from all WEM generators are tracked
Cons	• Targets can be inaccurate if forecast model has errors • If a resubmission of forecasts is not made the target may remain inaccurate for extended periods	• SCADA data is historic and not a predictor of future generation • Resubmissions of forecasts would not be required

Moving from 5 Minute to 30 Minute Targets

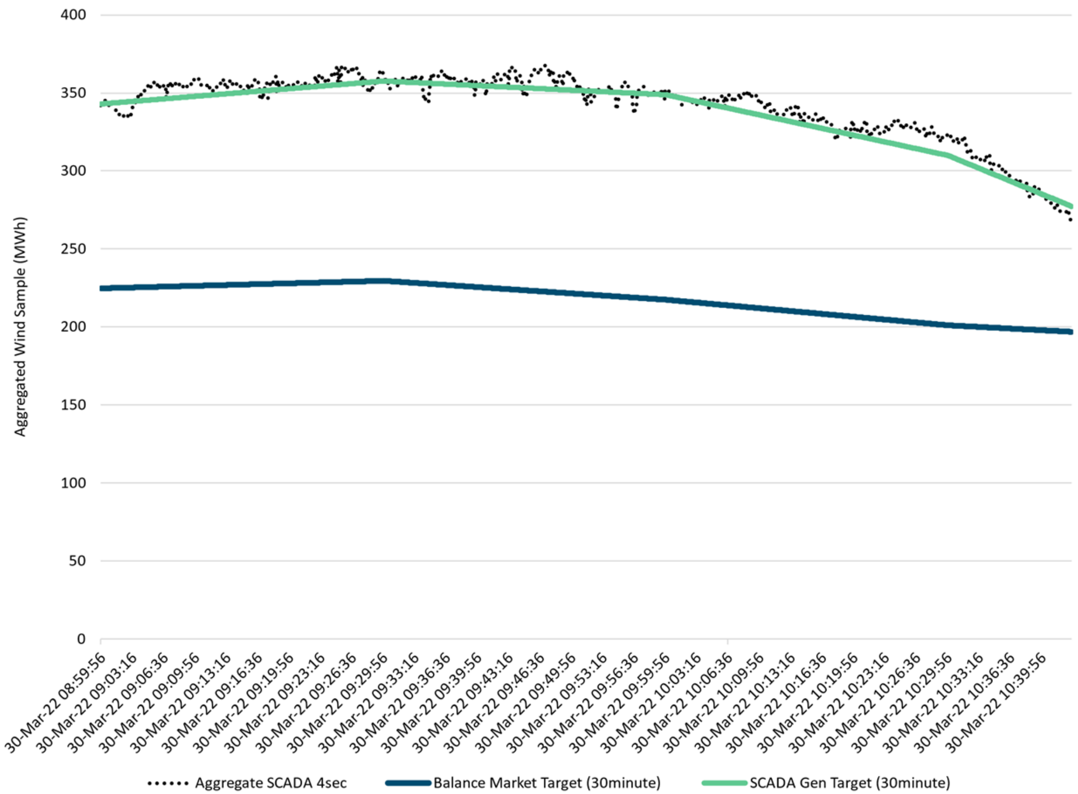
Aggregated Generation & Targets 30/03/2022



- Targets adjusted to use 30 minute publicly available SCADA data
- Calculate deviations from a linear ramp over 30 minutes (not average deviations from linear ramp within 5 minute intervals for each 30 minute period)
- Model still uses linear curve between points

Sourcing Targets from Balancing Market Submissions for Semi-Scheduled Facilities

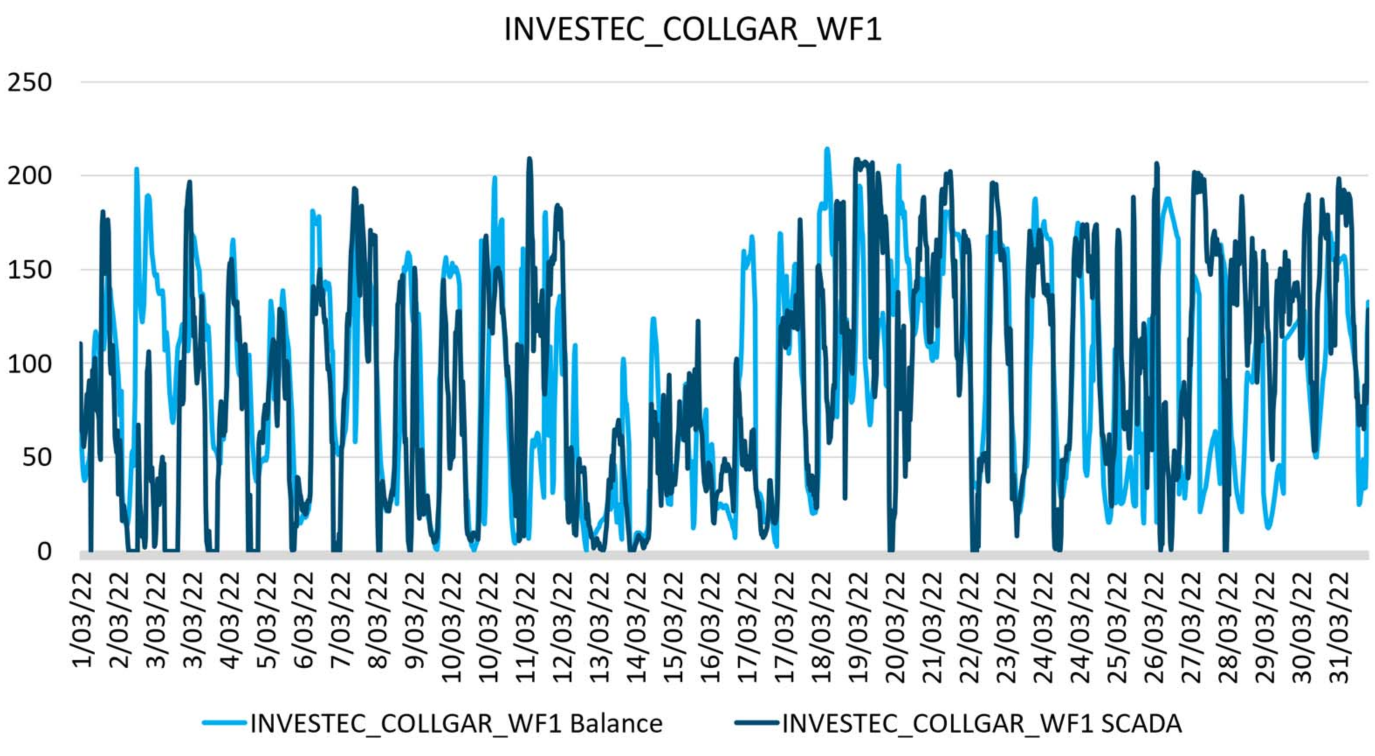
Aggregated Wind Generation & Targets 30/03/2022



- Targets were adjusted to use the Balancing Market submissions for renewable generation

Sourcing Targets from Balancing Market Submissions

Collgar Wind Farm Generation and Submission March 2022



- There are significant deviations between Balancing Market submissions for wind facilities and actual generation
- Deviations are much less for solar facilities (more predictable)

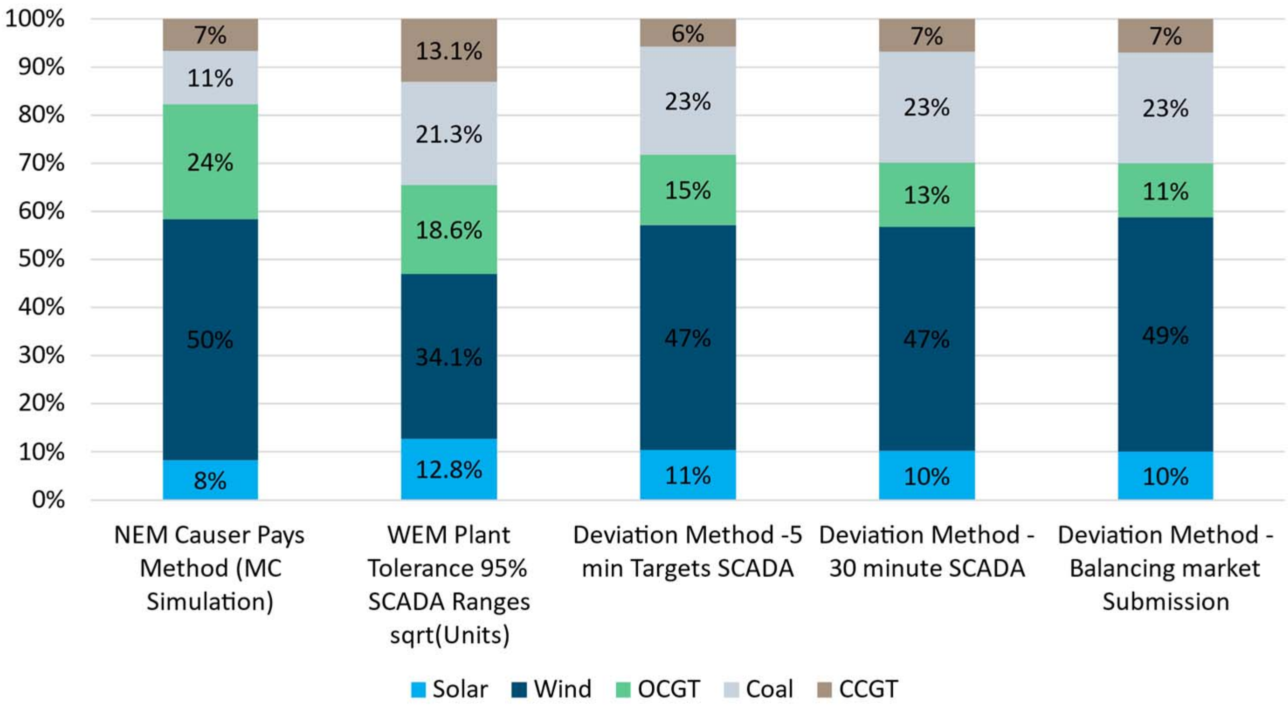
Working together for a **brighter** energy future.

Options for Implementing the WEM Deviation Method

- Three options have been explored for calculating the contribution factor under the WEM Deviation Method
  - Standard Deviation Method – use the standard deviation from the target in a 30 minute period
  - Summation Method – use the sum of the absolute value of deviations from the target in a 30 minute period
  - Maximum Absolute Deviation Method – use the single highest absolute value of deviation from the target in the 30 minute period

WEM Deviation Method Contribution Factors by Technology

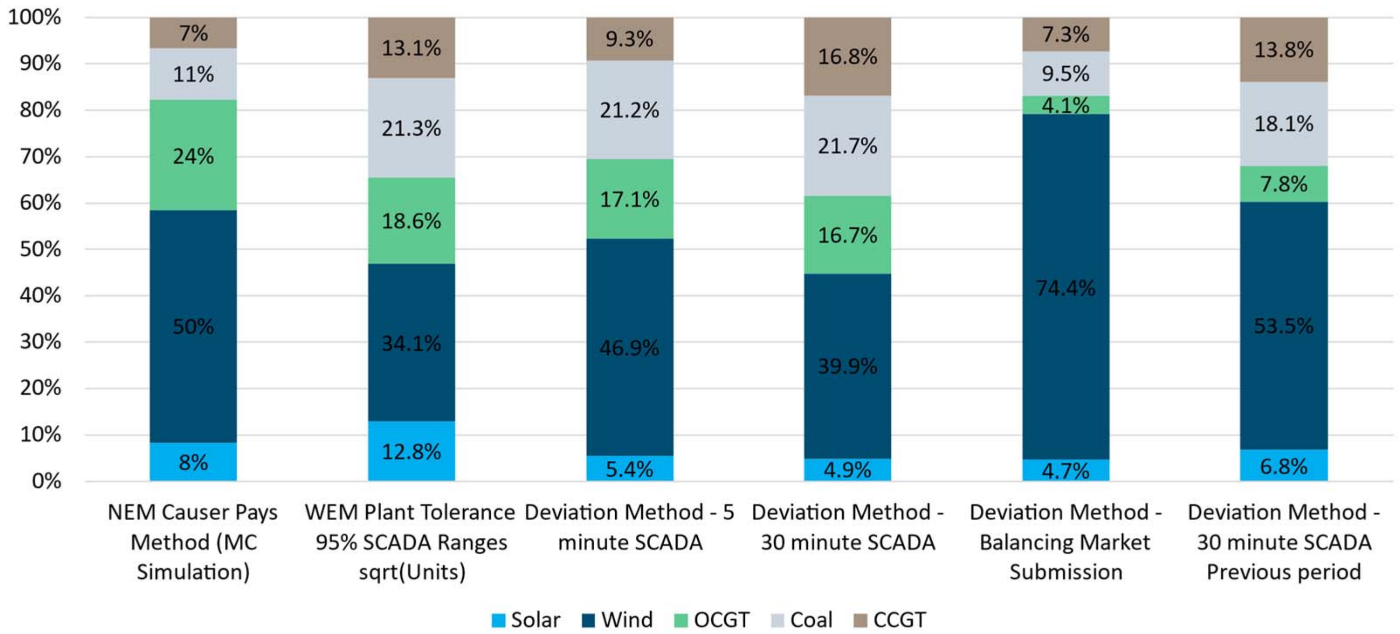
Frequency Regulation Cost Recovery Factors (%) – Standard Deviation Method



- The standard deviation method shows only a small change in contribution factors between the switch from 5 to 30 mins and from SCADA to Balancing Market Submission targets (balance forecast)
- The standard deviation method assigns costs based on generation variability – this rewards generators that provide a stable level of generation

WEM Deviation Method Contribution Factors by Technology

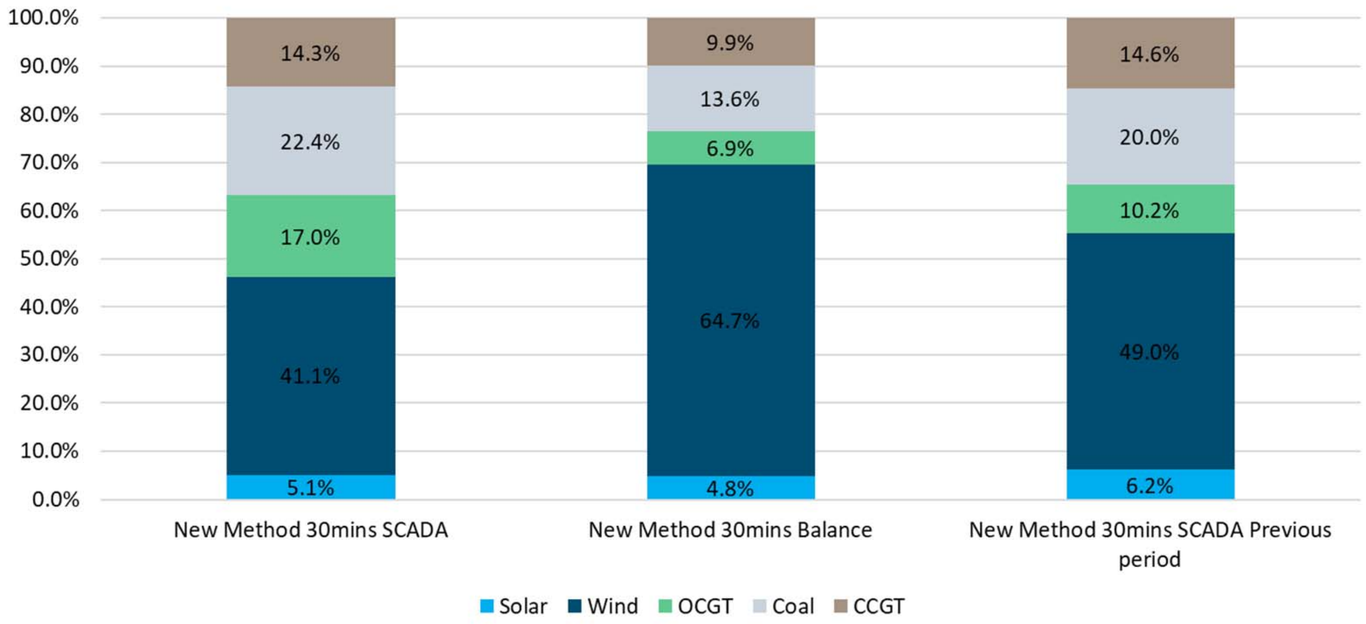
Frequency Regulation Cost Recovery Factors (%) – Summation Method



- The Summation Method shows that changing to the Balancing Submission targets assigns more costs to wind facilities
- Wind facilities are allocated more costs due to their inability to accurately predict their sent out generation

WEM Deviation Method Contribution Factors by Technology

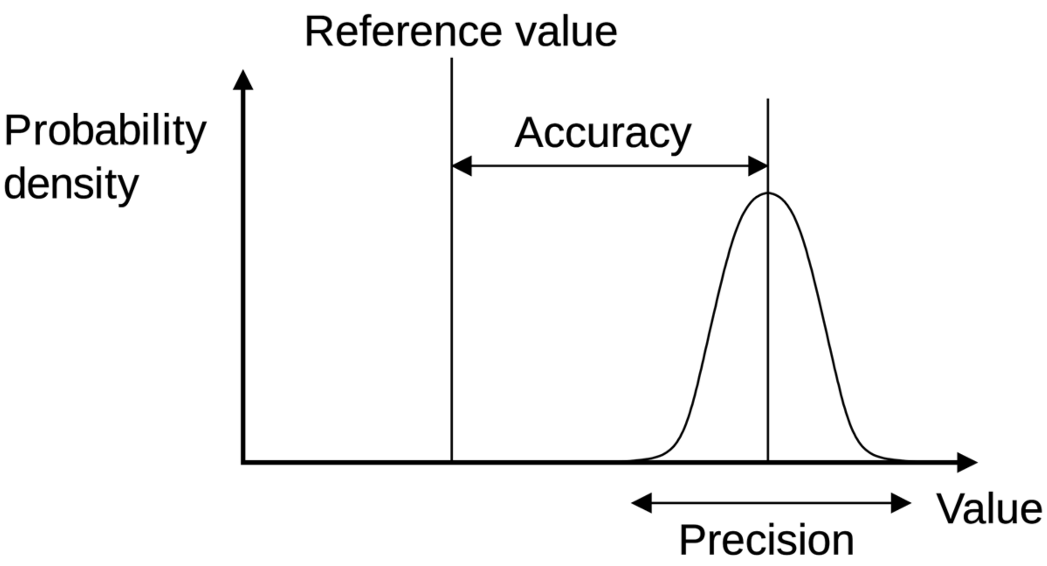
Frequency Regulation Cost Recovery Factors (%) – Maximum Absolute Deviation Method



- This approach assigns more costs to generators that have a significant deviation between forecasts and actuals for a 4 second period – this provides a strong incentive to minimise generation deviations
- However, once a large deviation occurs, participant has no incentive to minimise deviations below maximum deviation for remainder of the period

WEM Deviation Method Contribution Factors by Technology

Frequency Regulation Cost Recovery Factors (%) – Standard Deviation and Summation Methods



Source https://en.wikipedia.org/wiki/Accuracy_and_precision

- Standard Deviation method rewards precision (minimising variations around a forecast)
- Summation method rewards accurate forecasts

Recommendation

- EPWA recommends implementing the WEM Deviation Method using:
  - use SCADA data to measure deviations from a linear target in a 30 minute period; and
  - summation of the absolute value of deviations from the linear target.
- Does the CARWG support this approach?

6(b) Contingency Reserve Raise – Treatment of Multiple Dispatchable Units under the Runway Method

Response to Participant Feedback

Proposal (3) Where a Facility has multiple units with separate network connections, adjust the runway method for Contingency Reserve Raise so that each unit is treated separately		
Participant	**Issues Raised**	**Response and Potential Solutions**
AEMO	• Supports the policy intent but further work is required on practical implementation, including how costs will be assigned for aggregations based on Facility risk and on defining how multiple aggregated assets with multiple different risk profiles will be treated.	
Alinta Energy	• Broadly supports.	
Expert Consumer Panel	• Generally supports. • Suggest that the Facility Risk Value to be used for allocating the costs should use the largest single credible contingency that could occur for a Facility, even for Facilities with multiple units and more than one network connection. It may be necessary for Western Power and the Facility owner to determine the largest credible contingency for a Facility in some instances.	
Perth Energy	• Generally supports but it is essential that AEMO ensure that there are no other points of common mode failure that could take all units off-line simultaneously	

Response to Participant Feedback

Proposal (3) Where a Facility has multiple units with separate network connections, adjust the runway method for Contingency Reserve Raise so that each unit is treated separately		
Participant	**Issues Raised**	**Response and Potential Solutions**
Shell Energy	• Does not support. Need to consider what behavioural change this will drive. • Queried if modelling has been undertaken of Facilities with multiple connections to determine the risk value of such Facilities, as the risk value should not necessarily decrease due to multiple connections. • Noted that: a) if the proposal is simply an improvement on the existing method, then it is hard to build an argument against the concept of treating the output from separately connected units as two distinct contingencies; b) there is no transparency as to how an assessment of Facilities' risk value would be conducted; c) assessment of Facilities' risk value is likely to be subjective; and d) the change is unlikely to result in a net-benefits to customers, the overall cost of Contingency Reserve is unlikely to change, so the implementation costs are unlikely to be recovered.	• If individual dispatchable units at a site are highly unlikely to have a coincident Forced Outage because they are electrically separate (e.g., separate network connection, and separate sets of inverters connected to a control board), then the Facility risk value should be calculated on the basis of individual dispatchable units, not in aggregate for the Facility. Aggregating the multiple dispatchable units will over-estimate the risks and over-recover Contingency Reserve Rise costs.
Synergy	• Supports the intent of this Proposal. AEMO should only apply this method for Facilities where units are truly operated independently of each other. • Need to ensure that Facilities are given the right incentives to minimise power system risk, without incentivising the avoidance of costs via aggregating multiple units and benefitting from treatment as single units.	

Method for Determining Facility Risk Value

- AEMO to assess whether the multiple dispatchable units at a Facility are likely to have a coincident outage using the following steps:

1. Does each dispatchable unit (or set of inverters) have its own onsite electrical distribution system, which includes having a separate switchboard and metering for each dispatchable unit (or set of inverters)?

The dispatchable units use a common onsite electrical distribution system → An outage of the onsite electrical infrastructure will likely result in an outage for all of the units → Treat the units as a single aggregated unit under the Runway Method

Each dispatchable unit has a separate onsite electrical distribution system → Move to step 2

2. Does each dispatchable unit have a separate network connection?

The multiple dispatchable units have the same network connection → Treat them as a single aggregated unit under the Runway Method

The multiple dispatchable units all have separate network connections (e.g. a solar farm that has a separate network connection for each set of inverters) → Assign a Facility Risk Value to each dispatchable unit and calculate the Contingency Reserve Raise liability at the dispatchable unit level (not the Facility level)

- **It is proposed to amend the WEM Rules so AEMO includes this assessment it the relevant WEM Procedure**

6(b) Contingency Reserve Lower – Potential Changes to Proposed Allocation Method

Response to Participant Feedback

Proposal (4) Apply a Modified Runway Method to Allocate Contingency Reserve Lower Costs		
Participant	**Issues Raised**	**Response and Potential Solutions**
AEMO	• Agrees with the principle of the proposed approach, but is unclear on implementation, and would like to consult further on detailed design.	
Alinta Energy	• Broadly supports.	
Perth Energy	• Supports.	
Synergy	• Supports the approach. • Notes that aggregating small loads may create inconsistencies in the allocation of costs to loads above/below 120MW. • Supports adjusting the methodology to cater for future load contingencies exceeding 120MW.	
Neoen (verbal submission)	• Concerned that the application of the modified runway method above 120 MW may create bias against BESS in the SWIS. BESS has a very low risk factor, and this must be considered.	• Consider alternative allocation methods.

Cost Recovery for Contingency Lower – Current Proposal

Four Load Case		Tranche Cost Allocation				
Generator	Load Size (MW)	A only	A&B only	A&B&C&D	Total (MW)	
Load A	250	100	30	120	250	
Load B	150	0	30	120	150	
Load C	120	0	0	120	120	
Load D	Small Loads	0	0	1800	1800	
Tranche Amount (MW)		100	60	2160	2320	
Cost Share Interval	Load Size (MW)	40%	12%	48%	100.0%	Cost Share
Load A	250	318.0	47.7	21.2	386.9	48.7%
Load B	150	0.0	47.7	21.2	68.9	8.7%
Load C	120	0.0	0.0	21.2	21.2	2.7%
Load D	1800	0.0	0.0	318.0	318.0	40.0%
Total		318.0	95.4	381.6	794.9	100%
Cost Recovery Factor	Load Size (MW)					Cost Share
Load A	250	40.00%	6.00%	2.67%		48.7%
Load C	150	0.00%	6.00%	2.67%		8.7%
Load D	120	0.00%	0.00%	2.67%		2.7%
Load E	1800	0.00%	0.00%	40.00%		40.0%

- Threshold = 120 MW
- Assuming Load A (250 MW) and B (150 MW), a 250 MW load will be allocated about 48.7% of the Contingency Reserve Lower costs under the proposed modified runway method. This compares to around 10.78% under the current cost allocation methodology

Cost Recovery from BESS in the SWIS – Alternative Proposal

Alternative proposed to:

- Allocate costs to Loads pro-rata based on energy consumption, with separate allocations to loads above and below a threshold
- Increase the threshold to 150 MW (from 120 MW in current proposal)

Four Load Case		Tranche Cost Allocation				
Generator	Load Size (MW)	A only	A&B only	A&B&C&D	Total (MW)	
Load A	250	100	0	150	250	
Load B	150	0	0	150	150	
Load C	120	0	0	120	120	
Load D	Small Loads	0	0	1800	1800	
Tranche Amount (MW)		100	0	2220	2320	
Cost Share Interval	Load Size (MW)	40%	0%	60%	100.0%	Cost Share
Load A	250	318.0	0%	32.2	350.2	44.1%
Load B	150	0.0	0%	32.2	32.2	4.1%
Load C	120	0.0	0%	25.8	25.8	3.2%
Load D	1800	0.0	0%	386.7	386.7	48.6%
Total		318.0	0%	476.9	794.9	100%
Cost Recovery Factor	Load Size (MW)					Cost Share
Load A	250	40.00%	0.00%	4.05%		44.1%
Load C	150	0.00%	0.00%	4.05%		4.1%
Load D	120	0.00%	0.00%	3.24%		3.2%
Load E	1800	0.00%	0.00%	48.65%		48.6%

- This proposal would change Load A's allocation of Contingency Reserve Lower costs from 48.7% to 44.1%

Recommendation for Allocating Contingency Reserve Lower Costs

- The proposed allocation method for Contingency Reserve Lower service (use of the runway method above a 120 MW threshold) increases the recovery of Contingency Reserve Lower costs for a 250 MW load from 10.8% to 48.7%
- The alternative proposal (proportional allocation of costs above/below a 150 MW threshold) reduces the increased recovery for Contingency Reserve Lower costs for a 250 MW load from 48.7% to 44.1%
- The purpose of the new Contingency Reserve Lower cost allocation method is to attribute more of the costs to Facilities that cause the increased Contingency Reserve Lower requirement, based on the causer-pays principle
- The new Contingency Reserve Lower cost allocation method may provide an incentive to install two 125 MW load connections rather than one 250 MW connection to avoid higher Contingency Reserve Lower charges
  - This would also reduce the requirement for Contingency Reserve Lower services and lower overall Essential System Services costs
- **Another alternative option is for AEMO to assign risk factors to the different types of loads**

o For discussion by the CAR Working Group

6(d) Market Fees – BESS Cost Recovery

Response to Participant Feedback

Proposal (1)(b) Ignore recharge energy when allocating Market Fees to storage facilities		
Participant	**Issues Raised**	**Response and Potential Solutions**
AEMO	• Recommends storage Facilities are charged on both withdrawal and injection, as this is the basis on which cost are incurred in managing the system and market. • Ignoring recharge when allocating Market Fees would result in associated costs being recovered from other Market Participants.	• Check for consistency with current allocation of Market Fees to generators that both import and export power. • Outline the inequity that results between OCGT and BESS that are essentially performing the same function if BESS are allocated costs on recharge and discharge.
Alinta Energy	• Broadly Supports	
Australian Energy Council	• Supports	
Perth Energy	• Agrees that storage Facilities should only be charged once but recharge energy is a more appropriate measure, as this is a fairer parallel to charging generators and loads on their gross usage.	
Shell Energy	• There is a need to consider the implementation costs associated with suggested treatment of storage Facilities to ensure that there is a net benefit.	
Synergy	• Agrees in principle, but further consideration is needed as to how this will work for hybrid Facilities, and if the treatment for hybrids will differ depending on the Facility structure.	• Outline treatment of hybrid Facilities under the preferred approach.

Current Billing Determinants for Market Fees

- Both Metered Generation and Metered Loads are used as billing determinants under the current Market Fee allocation method
- A Facility's Metered Schedule for a Trading Interval reflects its loss-adjusted meter reading for that interval
  - AEMO performs the loss adjustment by applying static Loss Factors to the unadjusted meter reading, so that it is loss-adjusted to the Reference Node (Muja)
  - In effect, both generators and loads are charged for the energy they deliver or take from the Reference Node
- This implies that:
  - if a Market Generator has an outage (no exports to grid) and uses energy onsite (for onsite equipment), then the generator effectively becomes a load and Market Fees will apply to the Metered Load
  - if a Market Load has onsite generation and spills energy into the grid (generation exceeds local load), then the load has Metered Generation and Market Fees will be applicable to the Metered Generation
- In effect, both a load and generator will be liable for Market Fees for energy delivered to the node and consumed at the node
- To ensure consistency with the current application of Market Fees, it could be argued that BESS should be charged for both energy discharged to the node and recharged from the node
  - However, such a practice will over-recover Market Fees from the BESS

BESS and OCGT Cost Recovery (NEM)

- As outlined in the international review of Market Fees, market and system operator costs are a function of the number of market participants, not the amount of energy traded through the market
- Capital spent on market and system management systems, and labour and materials required to manage the business are a function of the original market design, market rules, number of participants, complexity of the market and the amount of automation used by the Market Operator
- The amount of energy traded through the market is not likely to be a major cost driver – however, it continues to be used as billing determinant for Market Fees, which can result inequities for the cost allocation to BESS
- The following slide highlights the potential inequity that can result in the NEM (2022-23) from allocating costs to an Open Cycle Gas Turbine (OCGT) and BESS (4 hours of storage), if the BESS is charged for both discharge and recharge
- In effect, the OCGT and the BESS provide similar services (both have a capacity factor of 15%), but the Market Fees recovered from the BESS will be 154% higher than for the OCGT if the BESS is charged based on both discharge and recharge from the node

NEM 2022/23 Market Fees Allocated to OCGT and BESS

Variable	Units	OCGT	BESS
Capacity	MW	100	100
Storage	MWh		400
Capacity Factor	%	15%	15%
Discharge	MWh	131,400	131,400
Recharge	MWh		146,000
Capacity Charge	$/annum	48,274	48,274
Generation Sent Out Charge	$/annum	23,053	23,053
Load Charge	$/annum		110,084
Total Charge	$/annum	71,328	181,412
Over-Recovery of Market Fees	%		154.3%

- It could be argued that OCGTs and BESS provide similar services (both have a 15% capacity factor)
- Market Fee allocation should ensure that Facilities that provide similar services should pay similar Market Fees unless AEMO has identified that there are specific differences in costs between the Facility types
- To ensure equity between OCGT and BESS it is proposed that Market Fees should only be recovered from BESS for discharge to the node

Hybrid Facilities

- Hybrid Facilities include co-located renewable and BESS systems – how should such Facilities be treated in terms of Market Fee Cost recovery under the preferred method?
- For a renewable/BESS plant, assuming it has only one connection to the grid:
  - the plant can recharge the BESS system directly (behind the meter), which reduces metered generation from the renewable plant and the allocation of Market Fees; but
  - when the BESS exports to the grid in a later period, Market Fees will be applicable to those BESS exports
- A standalone renewable plant (no BESS) and a hybrid Facility (renewable plant with BESS) will be allocated similar Market Fees – the only difference will be energy losses associated with the BESS (~10%), so Market Fee cost recovery from the hybrid Facility will be ~10% less than for a standalone renewable plant
- The BESS is not likely to recharge from the grid in this example since it is co-located with the renewable plant, so the Market Fees on grid recharge are not likely to be relevant

7. Next Steps

Next Steps

- Finalise WEM Deviation Method (using summation of deviations from a linear dispatch target over 30-minute dispatch intervals).
- Finalise the Contingency Reserve Lower method based on the CAR Working Group discussion
- Propose amendments to the WEM Rules to implement the Contingency Reserve Raise proposal