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

Meeting Agenda

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	Tuesday 13 December 2022
Time:	2:00 PM – 4:00 PM
Location:	Online, via TEAMS.

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda • Conflicts of interest • Competitions Law	Chair	Noting	2 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	Minutes of Meeting 2021_11_15	Chair	Decision	2 min
4	Action Items	Chair	Noting	2 min
5	Market Development Forward Work Program	Chair/Secretariat	Discussion	5 min
6	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Noting	2 min
	(b) Reserve Capacity Mechanism Review Working Group (**RCMWG**)	RCMRWG Chair	Discussion	40 min
	(c) Cost Allocation Review Working Group (**CARWG**)	CARWG Chair	Discussion	45 min
7	Rule Changes			
	(a) Overview of Rule Change Proposals	Chair/Secretariat	Noting	2 min
8	Supplementary Reserve Capacity	Chair/Secretariat	Noting	13 min
9	General Business	Chair	Discussion	5 Min
	Next meeting: 9:30am Thursday 2 February 2023			

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

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

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

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

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

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

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

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

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

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

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

Sensitive Information means and includes:

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

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

Guiding Principle – what not to discuss

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

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

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

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

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

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

Compliance Procedures for Meetings

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

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

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	15 November 2022
Time:	9:00am –10:54am
Location:	Videoconference (Microsoft Teams)

Attendees	Class	Comment
Sally McMahon	Chair	
Neetika Kapani	Australian Energy Market Operator (**AEMO**)	Proxy for Dean Sharafi
Martin Maticka	AEMO	
Zahra Jabiri	Network Operator	
Genevieve Teo	Synergy	
Christopher Alexander	Small-Use Consumer Representative	
Noel Schubert	Small-Use Consumer Representative	
Geoff Gaston	Market Customer	
Patrick Peake	Market Customer	
Timothy Edwards	Market Customer	
Wendy Ng	Market Generator	
Oscar Carlsberg	Market Generator	Proxy for Jacinda Papps
Rebecca White	Market Generator	
Paul Arias	Market Generator	
Peter Huxtable	Contestable Customer	
Noel Ryan	Observer appointed by the Minister	
Rajat Sarawat	Observer appointed by the Economic Regulation Authority (**ERA**)	

Also in Attendance	From	Comment
Dora Guzeleva	MAC Secretariat	Observer
Shelley Worthington	MAC Secretariat	Observer
Sally Ryan	AEMO	Presenter
Erin Stone	AEMO	Observer

Also in Attendance	From	Comment
Tim Robinson	Robinson Bowmaker Paul (**RBP**)	Presenter
Grant Draper	Marsden Jacob Associates (**MJA**)	Presenter
Peter McKenzie	MJA	Observer

Apologies	From	Comment
Dean Sharafi	AEMO	
Jacinda Papps	Alinta	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:00am with an Acknowledgement of Country. The Chair advised the MAC that her appointment as Commissioner to the Australian Energy Market Commission (**AEMC**) commenced on 10 October 2022. The Chair noted that she would continue in the roles of independent Chair of the MAC, the PAC and the GAB. She also noted any advice to the Coordinator from the MAC presents the views of the MAC and not necessarily represent the views of the Chair. The Chair declared her ownership of shares relevant to the energy sector, including shares in FMG, Woodside and Mineral Resources, although she has already disposed of shares in FMG and Woodside. The Chair also advised that she is still a member of the expert panel on the Electricity Review Board (**ERB**) but that she will resign from this position as a result of being appointed Commissioner on the AEMC once the substantive ERB decision is made on Application 1 of 2019, which is expected before the end of November 2022. The Chair advised that she is no longer special advisor to the Coordinator of Energy.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance and apologies as listed above. The Chair noted the competition law obligations of the MAC members, asked that members read the paper outlining these obligations and invited members to bring any matters they may identify to the attention of the Chair.	
3	**Minutes of Meeting 2022_10_11** The MAC accepted the minutes of the 11 October 2022 meeting as a true and accurate record of the meeting. **Action: The MAC Secretariat to publish the minutes of the 10 October 2022 MAC meeting on the Coordinator's Website as final.**	**MAC Secretariat**

Item	Subject	Action
4	**Action Items** The Chair noted there were no open action items.	
5	**Market Development Forward Work Program** The paper was taken as read	
6	**Update on Working Groups**	

(a) AEMO Procedure Change Working Group (APCWG)

Mr Maticka noted that relevant the papers were published on AEMO's website on 11 October 2022 and the presentation was uploaded 14 November 2022.

Ms Ryan noted that there were two reasons for bringing this procedure change proposal to the MAC:

- fuel supplies are currently a high profile issue that has been in the press, drawing attention to reliability over the summer; and
- the proposed changes are intended to apply to the current round of certification for which applications close on 14 February 2023.

Ms Ryan noted that AEMO was currently managing a tight supply/demand situation and has called for supplementary capacity for the coming summer. The latest Electricity Statement of Opportunities indicates an 8 MW surplus in 2024/25 and deficits beyond that.
Ms Ryan indicated that AEMO is looking for investment over the medium term because the Wholesale Energy Market (**WEM**) is entering a tighter supply/demand situation than it has seen for the last decade.

Ms Ryan noted there are some fuel supply challenges that have been well covered in the media, and the preliminary forecast in the early Gas Statement of Opportunities indicates a tightening gas market over the coming years.

Ms Ryan noted that AEMO must form a reasonable expectation of the amount of capacity likely to be available in peak periods and, given that it is aware of current and future fuel supply problems, AEMO feels it will be beneficial to obtain additional information to provide greater confidence and certainty in the capacity certification process.

Ms Ryan noted that the main changes to the procedure relate to the information requirements in the certification process. The intent was to make clear what information AEMO requires to form a reasonable expectation about the amount of capacity available for the 2024/25 capacity year. The information requirements relate to the nature of the fuel supply, including:

- transportation;
- measures put in place to manage risks around fuel supply;
- fuel reserves; and
- mitigations to manage any risks that are evident or foreseeable.

Item	Subject	Action
	Ms Ryan indicated that the second component of the proposed changes is that AEMO has made explicit a few things that were previously implicit but perhaps not clear, including that AEMO: • in assessing certification applications, takes into account information about plant availability and capability, including fuel; • needs to weigh the likelihood and the impacts of any issues on power system reliability; and • is able to take into account any issues that it is aware of. Ms Ryan indicated that AEMO has proposed this procedure change to ensure that the best assessment is made in the certification process, based on information provided, to ensure that sufficient capacity is procured to meet forecast demand, which is the primary purposes of the RCM. Ms Ryan sought feedback from the MAC on whether it considers that the information that AEMO proposes to collect is reasonable and appropriate, or if anything has been missed that would be helpful to enable AEMO to assess Certified Reserve Capacity (**CRC**) applications. Ms Ryan noted that submissions close on 9 December 2022 and that an APCWG meeting was scheduled for 21 November 2022. Mr Carlberg noted he generally supported the intent of the proposal but that it was drafted too broadly in that it impacts all facilities, including gas facilities, which are not subject to the current restrictions. Mr Carlsberg noted issues with the 14-hour fuel requirement, which is too onerous, and indicated that AEMO already had a trigger to request this kind of information. It could use this in a more targeted way to obtain information from just those facilities for which it considers there may be an issue. Ms Ryan noted that, regardless of fuel type, AEMO needs to get a reasonable assessment of fuel delivery risks and that past performance is not necessarily a reliable indicator of future performance. Ms Ryan added that AEMO would welcome suggestions on the right terminology to use in the procedure. Ms Ryan agreed that the WEM Rules allow AEMO to collect this information and indicated that the procedure change proposal is trying to clarify what information is required. Ms Ryan indicated that this does not preclude AEMO from communicating regarding a particular facility if it was aware of a particular risk and ask that the risk is addressed. Ms Ryan noted that AEMO wants to clarify its expectations to everyone about the information that will assist it to make a firm assessment that AEMO can stand behind. Mr Alexander noted there was collective interest in a secure electricity supply over summer and, while the issue last summer was a network issue, no one wanted it repeated. Consumers are aware of what is	

Item	Subject	Action
	happening nationally and internationally and Mr Alexander believed there was a concern in this new environment. Mr Arias expressed concerns about the requirements, as drafted, and questioned if the back casting exercise (over the past three years) helps to achieve the intended outcome or gives an indication of what may be happening with fuel contracts in the next 24 to 36 months. Mr Arias also noted that the significant amount of data required in relation to gas supply would be a very onerous task and may lead to compliance issues. Ms Ryan, noted that using only 12 months of data would artificially inflate the relevance of a particular year, which is a good reason to look further back. This information would allow AEMO to conduct a risk assessment and to explain its decisions to certify particular facilities, and that the data would make AEMO aware of any fuel delivery risks and that there is a robust plan for managing those risks. Mr Peake agreed with Mr Carlsberg that the issue with gas supply is quite different from coal and asked if these changes provided an opportunity to get rid of the 14-hour rule. Ms White asked whether there was also opportunity to look at the Supplementary Reserve Capacity (**SRC**) procedure to clarify the process and noted that she could provide some more specific feedback offline. • Ms Guzeleva noted that the WEM Rules require a review of the SRC WEM Rules, which will be done in due course. • Ms Ryan added that AEMO was keen to also review the SRC procedure because the SRC process had not been run for some time and some things may not have worked as well as AEMO might have liked. • Ms White asked if the review would be done in time for the next potential SRC procurement. • Ms Guzeleva indicated that SRC cannot be run earlier than six months before the start of a capacity year and acknowledged that there will be some time pressures and noted that there will be consultation with stakeholders, including with the MAC. Mr Gaston noted that he was wary of the amount of information AEMO was seeking, which may lead to a reduction in Capacity Credits and would create the problem that AEMO was trying to avoid. Mr Edwards noted that the significant policy changes are probably the biggest distractor for new investment, not information. The Chair noted that members need to keep in mind the WEM objectives and there was a trade-off between the onus and effectiveness of the information, and AEMO's ability to ensure compliance. Mr Huxtable noted that reliability is very important for end-users but that this needs to be balanced against cost.	

Item	Subject	Action
	Mr Schubert supported Mr Alexander's and Mr Huxtable's comments and noted that a blanket requirement for lots of information from all generators might be overkill, and noted that dual fuel generators have a backup fuel and that AEMO may not need as much gas supply information from them. The Chair summarised that the MAC is conscious of the onus of the information but supported the need for an appropriate and effective risk assessment. Ms Ryan thanked the MAC, noted that the APCWG would meet on 21 November 2022, and advised the MAC that there was opportunity to contact AEMO for a one on one meeting, if required.	
	(b) RCM Review Working Group (RCMRWG) The papers for agenda item 6(b) were taken as read. MAC members are being asked to: • note the update on the assessment of options for penalties for high emission technologies; and • note the update on the EPWA's work on certification of intermittent generators; and • provide feedback on the planned further analysis in relation to certifying intermittent generators. <u>Penalties on High Emissions Technologies</u>: Ms Guzeleva noted that the Reserve Capacity Review Working Group (**RCMRWG**) was working within the constraints of the Draft Statement of Policy Principles on the Penalties for High Emission Technologies. Ms Guzeleva noted that options will be presented to the MAC on 13 December 2022 and that the RCMRWG expressed a preference for a penalty on actual energy produced and that the penalty should not implemented through the RCM. Ms Guzeleva indicated that a number of RCMRWG members provided options that might be available to implement the penalty, including; • an approach very similar to the UK arrangements, where technologies with emissions above a certain limit do not receive Capacity Credits; and • use of the LGC framework. <u>Certification of Intermittent Facilities</u>: Mr Robinson noted that the volatility in the year-on-year results of the assessment of intermittent generator output is a function of the inherent volatility of those generators, not the assessment method. A firm facility would not have year-to-year volatility under any of the proposed methods. Slide 9 shows the level of volatility that we are trying to deal with. Mr Robinson noted that: • the reason for the volatility of the outputs is because the fleet output is volatile in times of system stress;	

Item	Subject	Action
	• fleet performance varies significantly year to year and it varies significantly within the year in the high stress intervals; and • the best performance was in the year with the lowest peak demand. Mr Robinson noted that RBP wold review the Individual Reserve Capacity Requirements (**IRCR**) method because the IRCR intervals can be significantly different intervals to the high demand intervals and there could be mismatches with incentives where generators are incentivised to perform in one way and loads in a different way. Mr Robinson noted that the key point for MAC members was that the variation and volatility in the fleet output and the individual facility output drives the volatility. Mr Robinson noted the further analysis that is proposed is to look at how to address volatility between years without risking system reliability. Mr Robinson noted that in most years the fleet was outperforming its Relevant Level Method capacity credits, which highlights that the current method is too conservative and leads the market to buy more capacity than is needed. Mr Robinson noted that EPWA is looking for a method that reflects what facilities actually do in system stress intervals so consumers are not forced to pay for capacity that is not available when it is needed. Mr Gaston asked Mr Robinson to explain how IRCR intervals can in some cases be different than peak demand intervals. • Mr Robinson explained how IRCR intervals are picked. • Mr Gaston asked what the probability was of not getting almost all of the peak intervals in the IRCR intervals, noting that he thought that the IRCR intervals were pretty good measure and that the IRCR method may change through the RCM Review. • Mr Gaston noted that there might be a need to investigate whether the wind was the same across all IRCR days. • The Chair noted that there is no desire to change the method to artificially lower the Capacity Credits at the same time when more capacity is needed. Mr Gaston noted that addressing volatility is a commercial decision for the wind farms, and if they do not like the year-on-year volatility of the CRC results, then they should do something about it, like installing a battery. Mr Edwards raised concerns that future IRCR Trading Intervals may not reflect system stress if AEMO dispatches load reduction services such as the services contracted as supplementary capacity. Mr Robinson clarified that, for the purpose of the assessing intermittent generators, the system demand was adjusted for any dispatch of load reduction services. Mr Alexander noted that slide 10 generally shows that fleet is outperforming the allocated CRC, and asked about the symmetry of	

Item	Subject	Action

the risks. That is, if outperforming and underperforming can be equated or was there a need to worry about instances where there is underperformance and if that was considered.

- Mr Robinson noted that the risk is not symmetric – there is a risk of giving facilities fewer Capacity Credits then their performance would suggest, but if they are given too many Capacity Credits and they underperform, then it is consumers who suffer.

Mr Robinson noted that the further analysis and options to minimise year-to-year volatility of CRC allocations for intermittent facilities, to provide certainty for investors, would smooth that volatility in a way that reduces the number of Capacity Credits allocated, rather than increasing them for a particular year. Both the Hybrid Method and the Delta Method calculate a fleet Effective Load Carrying Capability (**ELCC**) number and then divide that up among the various facilities, trying to smooth that from year-to-year. One of the proposed principles is that the fleet CRC for the evaluation period should be a ceiling for the CRC allocated in a year, which avoids being overly generous.

- Ms White noted that there is a potential perverse outcomes for investment because the method does not incentivise it and, as indicated by Ms Ryan's earlier presentation, there is problem with capacity at the moment so now is not the time to risk that. Ms White also noted that, with regard to Mr Gaston's comment about wind farms needing to do better by installing a battery, there may be times when that is appropriate, but that this comes at a cost and noted that batteries can get Capacity Credits as well.

Mr Robinson noted that you could think of under allocating as short-changing generators, but under-allocating to intermittent generators also results in the need to buy more capacity, which also comes at a cost to consumers.

- Mr Carlberg was concerned with how long consideration of CRC allocation had been going on.
- The Chair noted that it is very difficult to forecast the future based on history in this space and that there is a trade-off between underestimating for the purposes of issuing Capacity Credits, which may mean customers pay more, versus over allocating and not having adequate supply, and asked if the MAC members supported further analysis.
- Ms Guzeleva noted that stage two of the RCM Review is still to come which will look at the IRCR. Ms Guzeleva also noted that there is an option to bring intermittent generators in line with everybody else where they pay refunds for non-performance and asked if members are willing to consider that.
    - Mr Carlsberg noted he did not agree with this option because wind farms are so volatile and will face a huge risk of refunds from one year to the next.

Item	Subject	Action
	The Chair noted that the MAC endorsed the further analysis proposed in relation to certifying intermittent generators. Mr Robinson advised that the plan is to bring CRC allocation to the RCMRWG in December 2022 for a final recommendation.	
	(c) CAR Working Group (CARWG) The paper 6 (c) was taken as read. The MAC was being asked to: note the update provided regarding further progress made by the Cost Allocation Review Working Group (**CARWG**) and endorse the proposed way forward for assessment of methods for allocation of frequency regulation costs. Ms Guzeleva noted that the upcoming CARWG meeting had moved from 22 to 29 November 2022 because of the need to develop further understanding of the Tolerance Method to allocate Frequency Regulation costs. Mr Draper noted the options that were discussed previously for the allocation of Frequency Regulation costs and noted that the current National Energy Market (**NEM**) Causer-Pays method was very complicated, with costs allocated over a 28 day period. This meant that participants could not change their behaviour until the following month to avoid Frequency Regulation charges. He noted that it was not appropriate to apply the method in the WEM. Mr Draper noted that the AEMO presented further information on the new NEM Causer-Pays Method to the CARWG on 25 October 2022. Under this method participants would be paid for providing a response to correct frequency deviations and those that did not would be charged. Charges were billed over a 7 day period providing a better incentive for participants to react and change their behaviour, which helps with efficiency and reduces the requirement Frequency Regulation. Mr Draper noted that this option was still in development and was not due to be implemented until 2025, so its outcomes are untested. He added that this method is quite complicated, although it is simpler than the current NEM method. Mr Draper provided an overview of the methodology that was used to assess each of the proposed methods to allocate Frequency Regulation costs. Mr Draper noted that the new NEM Causer-Pays methodology will effectively compensate parties for providing primary frequency response (**PFR**), which was not contemplated in the WEM as PFR is mandatory under the Generator Performance Standards. Mr Draper recommended that the MAC endorses deferring consideration of adopting the new NEM Causer-Pays Method until it has been successfully implemented in the NEM and the benefits demonstrated, and to reconsider AEMO's proposed Tolerance Range Method to allocate Frequency Regulation. Mr Draper advised that a meeting has been arranged with AEMO for further discuss the Tolerance Range Method and the next step would be to develop the	

Item	Subject	Action
	preferred approach for allocating Frequency Regulation costs for consultation in the Consultation Paper. Mr Schubert supported deferring the consideration of the new NEM Causer-Pays method and noted that the Tolerance Range Method seemed very complicated. Mr Schubert asked MJA to identify the impact on consumers of going one way or another. • Mr Carlberg supported deferring the consideration of the new NEM Causer-Pays method and noted that, more broadly, he would like the same considerations be applied to the Tolerance Range Method. He noted that the Essential Systems Service (**ESS**) market might not impact the WEM for very long given Synergy's planned investment in 2,000 to 4,000 MWh of storage. Mr Carlsberg noted that there were huge challenges with the transition itself and a complex ESS cost recovery method could detract from getting the amount of investment required over the next 10 years. • Ms White and Mr Edwards supported Mr Carlsberg's comments. The Chair noted that there was general endorsement of the proposed way forward for the assessment of methods for allocation of frequency regulation costs from the MAC.	
7	**Rule Changes** **(a) Overview of Rule Change Proposals** The paper was taken as read. There were no updates. Ms Guzeleva noted that the timeframe for the four rule change proposals will need to be extended and that the Coordinator would publish something shortly.	
8	**MAC Schedule** The Chair noted that the MAC Schedule for 2023 shifted the day of the meeting from Tuesdays to Thursdays and the schedule was accepted by the MAC.	
9	**General Business** The Chair noted a potential review of the operation of the MAC in early 2023, covering its effectiveness and role, and reminded MAC members of their role as representatives of their particular groups in light of the market objectives. Ms Guzeleva noted that Project Eagle was proceeding, which will consider changes to the market objectives, and that a consultation paper on the plan for this will be published. **The next MAC meeting is scheduled for 13 December 2022.**	

The meeting closed at 10:54am.

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_12_13

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
13/2022	MAC Secretariat to publish the minutes of the 11 October 2022 MAC meeting on the Coordinator's Website as final.	MAC Secretariat	2022_11_15	**Closed** The minutes were published on the Coordinator's Website on 15 November 2022.
14/2022	Mr Edwards to contact EPWA regarding treatment of GPS tests in the outage framework.	Mr Edwards	2022_10_11	**Closed** Mr Edwards will liaise with EPWA outside of the MAC.

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_12_13

1. Purpose

- To provide an update on the Market Development Forward Work Program provided in Table 1, including:
  - the Chair of the Reserve Capacity Mechanism Review Working Group (**RCMRWG**) is to update the MAC on the progress of the Reserve Capacity Mechanism (**RCM**) Review since the last MAC meeting – see Agenda Item 6(b); and
  - the Chair of the Cost Allocation Review Working Group (**CARWG**) is to update the MAC on the progress by the CARWG since the last MAC meeting – see Agenda Item 6(c).
- To provide an update on other issues to be addressed via the Market Development Forward Work Program provided in Table 4:
- 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@dmirs.wa.gov.au.

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

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

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Cost Allocation Review	A review of: • the allocation of Market Fees, including behind the meter (**BTM**) and Distributed Energy Resources (**DER**) issues; • cost allocation for Essential System Services; and • Issues 2, 16, 23 and 35 from the MAC Issues List (see Table 3).	• The MAC has established the Cost Allocation Review Working Group (**CARWG**). Information on the CARWG is available at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group, including: ○ the Scope of Work for the review, as approved by the Coordinator; ○ the Terms of Reference for the CARWG, as approved by the MAC; ○ the list of CARWG members; ○ meeting papers and minutes from the CARWG meetings on 9 May 2022, 7 June 2022, 30 August 2022, 27 September 2022 and 25 October 2022; and ○ meeting papers from the CARWG meeting on 29 November 2022. • The Chair will update the MAC on the progress by the CARWG since the last MAC meeting. The Chair of the CARWG will ask the MAC to review the draft Cost Allocation Review Consultation Paper and seek guidance from the MAC on the conceptual design proposals and question in the draft paper – see Agenda Item 6(c).
Procedure Change Process Review	A review of the Procedure Change Process to address issues identified through Energy Policy WA's consultation on governance changes.	• The MAC discussed a draft Scope of Work for this review at its meeting on 11 October 2022. MAC members provided comments on the draft Scope of Works at that meeting, and were asked to provide further comments by email. EPWA did not receive any further comments. • EPWA will update the Scope of Works to reflect the MAC discussions and, following the Coordinator approval of the Scope, will provide the final scope and a timeline for the review to the MAC in early 2023.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Forecast quality	Review of Issue 9 from the MAC Issues List (see Table 4).	• This review has been deferred.
Network Access Quantity (**NAQ**) Review	Assess the performance of the NAQ regime, including policy related to replacement capacity, and address issues identified during implementation of the Energy Transformation Strategy (ETS).	• This review will be commenced after completion of the RCM Review.
Short Term Energy Market (**STEM**) Review	Review the performance of the STEM to address issues identified during implementation of the ETS.	• This review has been deferred.
Review of the Participation of Demand Side in the Wholesale Electricity Market (**WEM**)	The scope of this review is to: • identify the different ways that Loads/Demand Side Response can participate across the different WEM components; • identify and remove any disincentives or barriers for Loads/Demand Side Response participating across the different WEM components; and • identify any potential for over- or under-compensation of Loads/Demand Side Response (including as part of 'hybrid' facilities") as a result of their participation in the various market mechanisms.	• The MAC discussed a draft Scope of Work for this review at its meeting on 11 October 2022. MAC members provided comments on the draft Scope of Works at that meeting, and were asked to provide further comments by email. EPWA did not receive any further comments. • EPWA will update the Scope of Work to reflect the MAC discussions and, following approval by the Coordinator of Energy, will provide the revised scope and a timeline for the review to the MAC in early 2023.

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

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

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

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
2	Shane Cremin November 2017	Allocation of market costs – who bears Market Fees and who pays for grid support services with less grid generation and consumption?	To be considered in the Cost Allocation Review.
16	Bluewaters November 2017	BTM generation is treated as reduction in electricity demand rather than actual generation. Hence, the BTM generators are not paying their fair share of the network costs, Market Fees and ancillary services charges. Therefore, the non-BTM Market Participants are subsiding the BTM generation in the WEM. Subsidy does not promote efficient economic outcome. Rapid growth of BTM generation will only exacerbate this inefficiency if not promptly addressed. Bluewaters recommends changes to the WEM Rules to require BTM generators to pay their fair share of the network costs, Market Fees and ancillary services charges. This is an example of a regulatory arrangement becoming obsolete due to the emergence of new technologies. Regulatory design needs to keep up with changes in the industry landscape (including technological change) to ensure that the WEM continues to meet its objectives. If this BTM issue is not promptly addressed, there will be distortion in investment signals, which will lead to an inappropriate generation facility mix in the WEM, hence compromising power system security and in turn not promoting the Wholesale Market Objectives.	To be considered in the Cost Allocation Review.
23	Bluewaters November 2017	Allocation of Market Fees on a 50/50 basis between generators and retailers may be overly simplistic and not consider the impacts on economic efficiency. In particular, the costs associated with an electricity market reform program should be recovered from entities based on the benefit they receive from the	To be considered in the Cost Allocation Review.

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

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

MARKET ADVISORY COMMITTEE MEETING, 13 December 2022

FOR DISCUSSION

SUBJECT: UPDATE ON AEMO'S WEM PROCEDURES

AGENDA ITEM: 6(A)

1. PURPOSE

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

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meetings	**Next meeting**
Date	21 November 2022	17 January 2023 (to be confirmed)
Market Procedures for discussion	WEM Procedure: Certification of Reserve Capacity for the 2022 and 2023 Reserve Capacity Cycles.	WEM Procedure: DER Information Register

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 30 November 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
AEPC_2022_01	AEMO proposed amendments to the Procedure to: • specify additional information a Market Participant must provide as evidence of fuel availability in its CRC application under clause 4.10.1(e)(v)(2) of the WEM Rules; and • clarify the matters AEMO may consider when determining its reasonable expectation of the amount of capacity likely to be available under clause 4.11.1(a) of the WEM Rules. AEMO also made other minor and administrative changes.	Out for Consultation	Consultation Closure	09/12/2022

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

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

Market Advisory Committee (**MAC**) Meeting 2022_12_13

1. Purpose

- The Chair of the Reserve Capacity Review Working Group (**RCMRWG**) to update the MAC on the activities of the RCMRWG since the last MAC meeting.
- The MAC to provide guidance on:
  - the RCMRWG's recommended options for the implementation of a penalty on high emission technologies; and
  - the proposed next steps.

2. Recommendation

The MAC is to:

(1) note the amended draft statement of policy principles

(2) note the minutes from the RCMRWG meeting on 13 October 2022;

(3) note the update from the RCMRWG meeting on 24 November 2022;

(4) support the RCMRWG's assessment that it is appropriate to shortlist options 1 and 6 for the implementation of a penalty on high emission technologies;

(5) inform the Coordinator about any preference for option 1 or 6 and the reason why; and

(6) agree with the next steps for finalising the shortlisted options for presentation to the Minister.

3. Process

- On 13 October 2022, the RCMRWG discussed four options for implementing penalties for high emission technologies in the context of the draft statement of policy principles. Minutes of the 13 October 2022 RCMRWG meeting are attached (**Attachment 1**).
- RCMRWG members provided comments after the 13 October 2022 meeting including two additional options.
- At the 15 November MAC meeting, the Chair of the RCMRWG provided an update on the assessment of the RCMRWG's assessment of options for high emission technologies.
- On 24 November 2022, the RCMRWG discussed the assessment of options to implement penalties for high emissions technologies including:
  - two further options in addition to the four options discussed at the 13 October RCMRWG meeting; and
  - the outcome of the assessment of the different options including effects on existing facilities based on available information about their emissions.

- The RCMRWG recommends that the following two options are further assessed and presented to the Minister:
  - Option 1 – emissions penalty per MWh, charged by interval; and
  - Option 6 – emission thresholds for RCM participation.
- The RCMRWG agreed on the below assessment of the two recommended options against the criteria of the draft statement of policy principles.

Policy Criterion	Option 1	Option 6
Actual Penalty imposed on high-emission technologies	Both options represent a penalty relating to actual emissions.	
Implemented through the WEM	Both options would be implemented through the WEM.	
Net zero cost impact on consumers	Option would require additional measures to avoid participants passing increasing operating costs through to consumers.	Option would not change require no further measures because it does not change the incentives for short run operating decisions.
Power system security and reliability are not compromised	Option is likely to bring forward exit of inflexible coal fired generation.	Option likely to bring forward exit of inflexible coal fired generation. Option provides certainty about the need to procure additional capacity.
Simple and lo-cost implementation	Both options would be relatively simple to implement.	
The accumulated penalties incentivise firming solutions to facilitate the growth in renewable intermittent generation	Option would collect penalties but these would only be available to incentivise new firming facilities as long as high emitting facilities stay in the market.	Option would not collect penalties but likely result in a higher Reserve Capacity Price for facilities that are not high emission technologies.

- **Attachment 3** provides a summary of the RCMRWG's discussion and the assessment of the identified options including:
  - qualitative assessment of options 1,2,4,5, and 6; and
  - quantitative analyses for the proposed shortlisted options 1 and 6.
- The purpose of the presentation is to assess whether the MAC::
  - agrees that shortlisting options 1 and 6 for further design is appropriate;
  - prefers either option 1 or 6 and understand the reasons for the preference; and
  - agrees with the proposed next steps (slide 23) to:

  - review emissions intensity figures for existing facilities to ensure accuracy of the assessment;
  - assess appropriate starting level and transition-in profile for penalty rate (option 1) or threshold (option 6); and
  - assess revenue sufficiency for new technologies (particularly long-term storage and capacity price level under shortfall conditions.
- Further information on the RCM Review is available on the RCM Review webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review

4. Attachments

(1) Amended draft statement of policy principles

(2) RCMRWG 2022_10_13 – Minutes of Meeting

(2) Reserve Capacity Mechanism Review Working Group – MAC Update

Government of **Western Australia**
Energy Policy WA

Draft Statement of Policy Principles: Penalties for high emission technologies in the Wholesale Electricity Market

The Government is considering how to introduce penalties for all (i.e. incumbent and new) high carbon emission electricity generation technologies in the electricity market in the South West Interconnected System (SWIS). This complements discussions about capacity mechanism design and incentives for connection of new renewable generation capacity in other jurisdictions.

The Coordinator of Energy (**Coordinator**) is already undertaking a review of the Reserve Capacity Mechanism (**RCM**) in the Wholesale Electricity Market (**WEM**). In accordance with clause 2.5.2 of the WEM Rules, the Minister for Energy is providing the following draft statement of policy principles to the Coordinator to consider this new policy:

The Coordinator is to:

1. progress the design and the implementation of the policy of introducing penalties for all (i.e. incumbent and new) high carbon emission electricity generation technologies in the WEM;
2. consider options and propose a preferred option for the application of the penalty;
3. as part of (2), consider whether this policy can be effectively and efficiently implemented through the RCM and whether a different option could better achieve the intended outcome;
4. as part of the existing RCM Review, examine options for utilising the collected penalties to provide incentives for the early entry of alternative “firming” technologies in the market to ensure reliability of supply is maintained in the transition to net zero emissions energy sector by 2050;
5. ensure that the introduction, and the utilisation of, the penalties do not reduce the effectiveness of the RCM in maintaining reliability on the SWIS or increase the overall cost to consumers; and
6. integrate the policy in the modelling currently undertaken and planned for the RCM Review.

Background

Clause 2.5.2 of the WEM Rules provides for the Minister to issue a statement of policy principles to the Coordinator with respect to development of the market, such as for the forthcoming RCM Review. The statement of policy principles must not be inconsistent with the Wholesale Market Objectives.

Energy Policy WA is seeking some enhancements to the legal framework, including the introduction of an overarching State Electricity Objective to replace the current WEM objectives. The State Electricity Objective will focus on promoting the long-term interests of consumers, rather than on an exhaustive list of objectives which may often be in conflict or present an obstacle for implementing specific Government policies.

The proposed State Electricity Objective will provide scope for the Minister to issue a final statement of policy principles to the Coordinator.

Consultation

Clause 2.5.2 indicates that the Minister may provide a draft of a proposed statement to the Market Advisory Committee (**MAC**) and seek the MAC's views on the draft statement.

A draft statement of policy principles was circulated to the MAC for review and comment at an out-of-session meeting in early August 2022, and the Coordinator has advised the Minister of the MAC's views.

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	13 October 2022
Time:	9:00am – 11:30am
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Rhiannon Bedola	Synergy	
Manus Higgins	AEMO	Until 11:00am
Toby Price	AEMO	Subject matter expert
Jacinda Papps	Alinta Energy	
Geoff Down	Water Corporation	Proxy for Peter Huxtable
Paul Arias	Bluewaters Power	
Mark McKinnon	Western Power	
Patrick Peake	Perth Energy	
Matt Shahnazari	Economic Regulation Authority	
Noel Schubert	Small-Use Consumer representative	
Andrew Stevens	Consultant	Until 11:10am
Rebecca White	Collgar Wind Farm	
Tessa Liddelow	Shell Energy	
Dev Tayal	Tesla Energy	Until 10:00am
Andrew Walker	South32 (Worsley Alumina)	Until 10:00am
Kiran Ranbir	ATCO Australia	
Daniel Kurz	SSCP Power	Until 11:00am
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	
Ajith Sreenivasan	RBP	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	
Shelley Worthington	EPWA	
Isadora Salviano	EPWA	

Apologies	From	Comment
Dale Waterson	Merredin Energy	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:00am and provided an update on the current work for the RCM Review and the RCMRWG work schedule. The Chair noted that, based on the submissions on the stage 1 consultation paper and initial analysis, EPWA determined that additional analysis is needed on the method to assign Certified Reserve Capacity (CRC) to intermittent generators. Therefore, this matter will not be discussed at this RCMRWG meeting as originally planned. The following meetings are planned for the remainder of the year: 13/11/2022 – Penalty for high emission technologies: discussion of options for assessment 24/11/2022 – Penalties for high emission technologies: assessment and modelling 15/12/2022 – Certification of Intermittent Generators analysis.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above	
3	**Minutes of RCMRWG meeting 2022_07_14 and RCMRWG meeting 2022_07_21** The RCMRWG noted the minutes from the working group meetings held on 14 July 2022 and 21 July 2022.	
4	**Action Items** The paper was taken as read.	
	The slides for agenda items 5 to 10 are available on the webpage for the RCM Review (https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group). Note that updated slides have been published after the meeting	
5	**Purpose of this session** Mr Robinson noted that the purpose of this meeting is to seek input on the direction and the proposed options for the implementation of penalties for high emission technologies and support of firming technologies.	
6	**Policy statement principles** Mr Robinson recapped the draft statement of policy principles and summarised the constraints and flexibilities for proposing a design for a penalty for high emission technologies. The following was discussed: • Ms White sought clarification on the purpose of the policy and if the intent is to incentivise investment in new technologies or if it is a	

Item	Subject	Action
	reaction to the absence of a broader economy wide emission scheme. ○ The Chair noted that this is the Minister's draft statement and that she cannot speak for the Minister but the statement of policy principle is clear that the purpose is to penalise high emission technologies and to incentivise firming technologies. ○ Mr Shahnazari considered that it is important to first set a clear objective or target for the policy. Mrs Papps agreed with Mr Shahnazari. ○ Mr Stevens considered that the penalty should not be discussed as part of the RCM Review because it is not a reserve capacity issue but an energy and emissions issue. Mr Stevens considered that providing available capacity does not contribute to emissions. ○ The Chair acknowledged Mr Stevens' view and agreed that the penalty should be based on actual emissions and not available capacity. The Chair noted that: – The draft statement has been discussed with the MAC and the MAC provided views that penalties may not be best addressed in the RCM. – EPWA had been asked to assess options for a penalty on high emission technologies as part of the RCM Review but the penalty could be implemented within or outside the RCM. – Including the assessment of options for the penalty in the RCM Review allows to assess the penalty and its impact as part of the modelling for the review. ○ Mr Peake and Mr Stevens considered that the RCMRWG is well placed to assess the issue and provide feedback including whether emissions are better addressed in the energy market than in the RCM. • In response to a question from Mrs Papps, the Chair noted that the draft statement is about getting to net-zero emissions and indicated that, for the purpose of the draft statement, firming technologies are low emission technologies, such as storage technologies and in particular long-duration storage, that use clean resources. ○ Mr Kurz considered that a mechanism that utilises penalties to support firming technologies can force high emission technologies to exit the market. Such a mechanism would not incentivise investment in firming technology because of the uncertainty of the support. • Mrs Papps considered that another constraint should be added to the draft statement, requiring competitive neutrality of the penalty regime. Ms White, Mrs Bedola and Mr Arias supported Mrs Papps suggestion.	

Item	Subject	Action
	○ The Chair acknowledged the desire for competitive neutrality but noted that any solution for implementing the policy must honour the existing constraints set out in the Minister's draft statement. • Mrs Bedola considered that the net zero cost impact on consumers will be difficult to meet. Penalties will change dispatch, investment and retirement and that will impact costs. Mr Peake and Mr Arias agreed with Mrs Bedola. • In response to a question from Mrs Bedola, the Chair noted that the Minister has not provided direction on the timing for the implementation of the penalty regime. Therefore, she considered that the timing would be part of EPWA's recommendations.	
7	**Policy implementation options** Mr Robinson presented identified number of options for designing a penalty on high emission technologies. The following was discussed: General • Mrs Papps considered that the penalty should be designed in a way so participants can manage their exposure to it. ○ The Chair agreed that, while it was not a stated objective, the penalty design should allow participants to change behaviour. Option 1- Penalty based on estimated emissions produced in each Trading Interval: • Ms White asked how the ERA would monitor compliance that bilateral contracts are not amended to pass through the penalty. ○ The Chair considered that, if the WEM Rules don't allow the penalty to be passed through when offering into the energy and Essential System Services markets, it is unlikely that the counterparty would agree to pass through the penalty in a bilateral contract. ○ Mr Shahnazari considered that if the penalty is not allowed to be passed through to consumers, then there is no increase in complexity for the ERA's compliance monitoring. ○ Ms White commented that in the near future demand is expected to exceed available energy, which would impact bilateral contracts and customers may not have the bargaining power to negotiate new contracts. • Mrs Papps asked how the penalty would affect the Benchmark Reserve Capacity Price (BRCP) considering the current reference technology is an open cycle gas turbine (OCGT). ○ The Chair noted that the penalty must not affect the BRCP, otherwise everyone who pays the penalty can recover it through the higher BRCP. Therefore, further consideration is needed about the treatment of the technology of the marginal capacity provider.	

Item	Subject	Action

	• Mr Peake noted that the government had already announced the retirement of Synergy's coal fired power plants by 2030 and expressed his concern that if the penalties are not to be passed through to costumers then it could lead to an early retirement of Synergy's and Bluewaters' coal fired facilities. This capacity will be difficult to replace in the short term.
	  ○ The Chair acknowledged Mr Peake's concern and noted that:
	    – it will be important to model the impact of the penalty on the generation fleet;
	    – the modelling results need to be reflected in the recommendations for the timing of the implementation;
	    – allowing to pass the cost through to the consumer would be against the constraints of the draft statement because such an option would not result in a penalty.
	  ○ Mr Peake considered that, if the penalty is introduced after the retirement of the coal fired facilities, the only high emission facilities will be gas fired facilities which are needed to firm up the intermittent generators.
	  ○ The Chair reiterated that special consideration must be given to facilities that are marginal capacity providers.
	  ○ Mr Arias considered that allowing participants to pass through the penalty to consumers would still fund the entry of firming technologies. Mr Kurz agreed with Mr Arias.
	  ○ Mr Shahnazari considered that passing penalties onto the energy market drives innovation and investment in low emission technologies and noted that there is a substantial body of knowledge on market based and administered mechanisms. Mr Shahnazari considered that for the policy constraint requiring that the implementation of the penalty has a net-zero-impact on consumers it should be clarified over what time frame the impact should be net-zero and whether the cost of emissions are included in the consideration.
	• Mr Robinson noted that modelling will assess:
	  ○ the impact on prices, thus the cost to consumers; and
	  ○ the impact on commercial viability of individual facilities, entry and exit decisions, and the effect on reliability.
	<u>Option 2 – RCM penalty based on settlement period emissions:</u>
	• There was some discussion about the first formula on slide 13.
	  ○ Mr Robinson clarified that the intent was to limit a facility's penalty to the emissions associated with its Capacity Credits.
	  ○ Mr Shanazari and Mr Schubert considered that the penalty should be based on actual emissions and not be related to a facility's Capacity Credits.	

Item	Subject	Action
	○ The Chair agreed that a facility's absolute penalty should be based on actual emissions and not be related to the number of Capacity Credits. However, in order to charge the penalty through the RCM, the absolute penalty, the Capacity Credits and the received capacity price need to be considered. Therefore, the formula will be changed as follows: ~~max(facility generation, facility capacity credits) * facility emissions rate~~ facility generation * facility emissions rate The Chair noted that slide 13 will be amended accordingly and recirculated. ○ Mrs Bedola asked how facilities that don't have Capacity Credits would be treated. – The Chair indicated that this issue will be further considered. Option 3- RCM penalty based on historic emission: • Mrs Bedola noted, that basing the penalty on historic emissions could incentivise a retiring plant to increase emissions in their last year as they won't get penalised for it. Mr Price and Mr Peake supported Mrs Bedola's comment. ○ The Chair agreed that this will need to be considered as part of the assessment. • Mr Peake considered that a penalty should not be based on historical generation because operations are likely to change dramatically over the years. Mr Kurz supported Mr Peake's statement. Option 4 - RCM penalty based on theoretical maximum emissions: • Mr Robinson noted that basing penalties on theoretical maximum emissions would disconnect them from actual emissions. Therefore, this option will likely not be further considered.	
8	**Common elements** The following was discussed: • Mr Stevens noted that all options presented are dealing with scope one emissions which are the focus of numerous mechanisms. Mr Stevens considered that any mechanism implemented in the WEM would likely be replaced soon by a federal mechanism. ○ Mr Robinson noted that scope one emissions are based on fuel consumption and not metered generation in MWh as in the options proposed. ○ Mr Robinson agreed that any WEM penalty for high emission technologies scheme should be revisited if a federal mechanism is implemented.	

Item	Subject	Action
	○ Mr Schubert considered that the fuel consumption could be determined by applying a factor to the generation measured in MWh to link the penalty to scope one emissions. ○ Mr Peake considered that a penalty regime based on MWh should be cheaper to operate because that information is readily available. • Ms White considered that: ○ Participants cannot materially decrease the quantity of energy a facility generates given its obligations to offer into the market (at SRMC or similar). Therefore, the only behaviour change available is retirement, which risks a potential capacity shortfall and firming issues. ○ The penalty should not be linked to Capacity Credits as this would add unnecessary complexity and delay or mute the signal for behaviour change. ○ The most suitable approach is to base the penalty on the actual energy generated and only apply the penalty to generators and not to storage facilities to avoid double penalising emissions. Mrs Bedola, Mr Peake and Mr Shahnazari supported Ms White's considerations. • Mr Schubert suggested an alternative approach for the implementation of the penalty using the Renewable Energy Certificates (REC) regime. He suggested that generators should be required to acquire RECs in proportion to their emissions and relinquish them to a state body such as AEMO or EPWA for the funding of firming technology. ○ The Chair asked Mr Schubert to provide the detail of his suggestion in writing. Mr Schubert agreed to email EPWA his suggestion. ○ The Chair noted that the RECs are administered by the Commonwealth Regulator and expressed concerns that the proposed approach could be seen as WA trying to dictate the evolution of the RECs beyond 2030. ○ Mr Stevens considered that a penalty regime using the RECs: – would attract legal challenges; and – would introduce investor uncertainty because of the variability of the RECs. ○ Mr Peake considered that RECs have high overhead costs. ○ Mr Schubert clarified that his suggested method could also be based on a WA local scheme instead of the RECs. ○ Mrs Bedola pointed out that this approach could cause an issue weighing WA certificates against national certificates.	

Item	Subject	Action
	○ Mr Price agreed with Mrs Bedola's concerns and added that the method would require definition of eligible certificates. • Mr Peake asked if it is possible to legally apply penalties to an estimated quantity of emissions. ○ Ms White presumed that the estimate would need to meet the National Measurements Act requirements of 'for trade' measurement. ○ The Chair noted that the certificate scheme in the Eastern States is based on estimates but indicated that legal impediments will need to be assessed. • Mr Shahnazari noted that for determining the emission penalty rate, the ERA's recent modelling could be a good framework. • In response to a comment from Mr Peake, the Chair clarified that the penalty would put a value on emissions and that different ways of setting the penalty rate will be assessed through modelling. • Mr Arias noted his disagreement with the statement that facilities in the SWIS don't currently face financial costs of emissions. • Mr Kurz agreed with Mr Arias and noted that high emitting facilities face higher costs for finance and insurance. • Ms White asked if the Minister has provided any guidance about the treatment of generators that are not connected to the SWIS. The Chair noted that no guidance had been provided.	
9	**Options for Distributing Support Payments** Mr Robinson presented a number of options for distributing the penalties to firming technologies. • Mr Schubert considered that the penalties should not be distributed to firming technologies via Capacity Credits but based on the energy delivered in a predetermined period of time. • Mrs Bedola asked whether the intent is to only support new technologies to assist their commercial viability. The Chair considered that this is the intent. ○ Mr Peake considered that the proposed hydrogen subsidy needs to be considered when designing the support for new firming technology. The Chair agreed. ○ Mr Schubert considered that the support should be used to make new firming technologies economic and not pay for their full cost. The Chair agreed. • Ms White raised a concern that, if the support is provided on a pro rata basis for Capacity Credits of firming technologies, as suggested under proposed option 1, participants with a portfolio of high emission technologies and firming technologies will pay the penalty and receive the support. Ms White questioned whether in this case the benefits justify the administration costs of the regime.	

Item	Subject	Action
	○ The Chair indicated, that the cost and benefits of each option will be assessed. • Mr Shahnazari expressed his support for a competitive mechanisms, or an administrative mechanism emulating a competitive outcomes, for distributing the penalties that does not pick winners and losers. • Ms White asked how the firming technologies that produce emissions will be treated. ○ The Chair considered that the policy intent is to support firming technologies that enable an overall increase in renewable generation and help achieve the goal of net-zero emissions. • Mr Price sought clarification on how renewable energy will be funded. ○ The Chair noted that this question is important but is out of scope for the assessment of penalties for high emission technologies. ○ Mr Robinson noted that the effect on prices and the possible entry and exit of facilities will be assessed as part of the economic modelling. . • Mr Schubert considered that enabling a high emitter to manage their exposure by receiving funds to build their own firming technology is a good thing. • Mr Shahnazari suggested to distribute the penalties to technologies based on the estimated reduction of high emission generation that can be achieved by their addition, similar to a cap and trade mechanism. Mr Shahnazari provided a reference to a paper he considered relevant.[1] • Mr Schubert considered that renewable conventional generation (e.g. biomass fired generation) should also be eligible for the support.	
10	**Next Steps** • The Chair requested feedback to be submitted to EPWA by 28 October 2022 to allow enough time for EPWA to assess and model the viable options before the next working group meeting on 24 November 2022. ○ Mrs Papps requested an extension of the timeline to 2 November 2022. ○ The Chair agreed to extend the timeline but encouraged all members to provide their input by 28 October 2022, if possible. • In response to a question from Mrs Bedola, the Chair noted that the policy for the penalties will be discussed with the MAC at the 13 December 2022 meeting.	

[1] note page 18 Paragraph 3 Incorporating Wind Generation in Cap and Trade Programs (nrel.gov)

Item	Subject	Action
	• Mr Peake considered that the timing for the implementation of the penalty should be set soon to provide certainty for new investment, for example in the needed high efficiency gas turbines. o The Chair noted that special consideration must be given to reliability and how required firming technologies that produce emissions will be treated. • In response to a question from Mrs Bedola, the Chair noted that the term 'high emission technologies' will need to be clearly defined for the purpose of the penalty.	
11	**General Business** No general business was discussed.	

The meeting closed at 11:30am.

Government of Western Australia
Energy Policy WA

Market Advisory Committee

Update from RCMRWG - Penalties for High Emission Technologies

13 December 2022

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

Policy Implementation Options

EPWA identified and, on 13 October 2022, presented to the RCM Review Working Group four main options for implementing this policy based on:

1. estimated emissions produced in each interval (energy settlement)
2. estimated emissions produced in each settlement period (energy settlement)
3. historical emissions produced in the prior capacity year (RCM)
4. theoretical maximum emissions that could be produced in each settlement period (least preferred option)

An important aspect of the penalty design is whether the penalty relates to the actual quantity of emissions produced, or the potential for emissions to be produced

The method used to distribute accumulated penalty amounts to encourage entry of firming technologies were presented separately to the approach to penalty implementation.

See appendix for workings of each option

Feedback Themes

EPWA received written feedback on the approach to penalties from five stakeholders: AEMO, Alinta, Noel Schubert, Perth Energy, and Shell Energy.

Common themes in the responses were that:

- The penalty regime should be kept separate from other parts of the WEM – i.e. not implemented through the RCM
- Sent out energy (MWh) was favoured as the basis for penalties, applied at a trading interval (option 1) or settlement period (option 2) to provide a link between operational actions and outcomes
- Achieving net zero cost impact on consumers will require a prohibition on passing penalty charges to customers through market offer prices
- Any penalty regime will drive existing firm capacity to retire earlier than planned at a time when significant new investment is needed in the SWIS – power system reliability will likely be negatively affected if retirement occurs before replacement capacity is available

RCM Review Working Group members have asked for a clearly stated objective to be included in the Minister's statement at each meeting.

Alternative Options Suggested

Stakeholders also identified two other options for applying penalties.

- One stakeholder suggested that participants could be required to acquire the equivalent of LGCs or ACCUs in proportion to their emissions, and surrender them to a state agency which would use them to fund firming capacity (**Option 5**)
- Two stakeholders suggested that EPWA consider the approach used in the UK, whereby capacity types with emissions intensity above a given threshold are ineligible to participate in the capacity mechanism (**Option 6**)

Stakeholders gave mixed feedback on the best mechanism for distributing support payments – there was support for making payments on the basis of MWh (generated or potential), but concern that support payments:

- Should only be made to capacity that is truly additional, and only to the extent that it is needed to make a project commercially viable
- Would disappear once high emitting facilities exit the market
- Would provide limited incentives for investment as the duration and size of payments in uncertain.

New Option 6 was proposed based on the UK Capacity Market's Emission Thresholds

- EU Electricity Regulations set limits on the emissions intensity of facilities participating in the capacity market
- In 2021, the UK made changes to its capacity market to implement these limits – there are two limits:
  - 0.55 tCO2e of Fossil Fuel origin per MWh of electricity generated ("the Fossil Fuel Emissions Limit"); and
  - 350 tCO2e of Fossil Fuel origin on average per year per installed MWe ("the Fossil Fuel Yearly Emissions Limit")
- New generation is only eligible for capacity payments if it has (fossil fuel sourced) emissions less than both limits
- Existing generation (pre 2019) is only eligible for capacity payments if it has (fossil fuel sourced) emissions less than the second limit

Option 6 – Emissions Threshold for RCM Participation

- Perform additional checks during CRC allocation for each facility:
    - Determine facility emissions (tCO2e) in previous capacity year as:

        *facility generation * facility emissions rate*

    - Determine whether facility emissions intensity is below threshold:

        facility emissions rate ≤ rate threshold

    - Determine whether actual facility emissions are below threshold:

        facility emissions ≤ quantity threshold

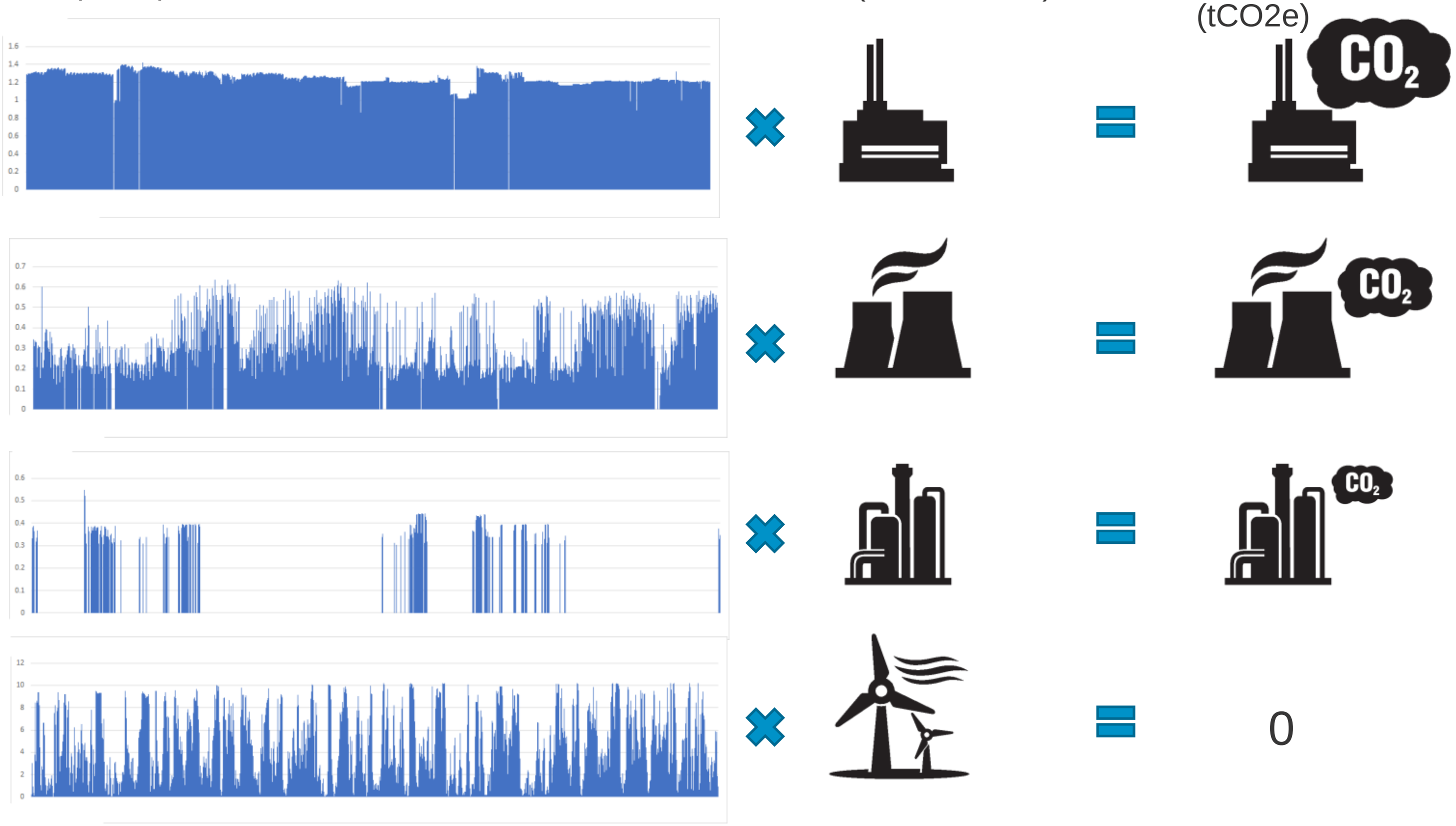
- If facility is above either threshold, CRC = 0
- The thresholds would apply to all new facilities at implementation
- **A higher threshold would be adopted for existing facilities**, and ratcheted down over time
- This option would not collect any penalty funds for redistribution

Option 6 (part 1)

Previous capacity year facility generation (MWh)

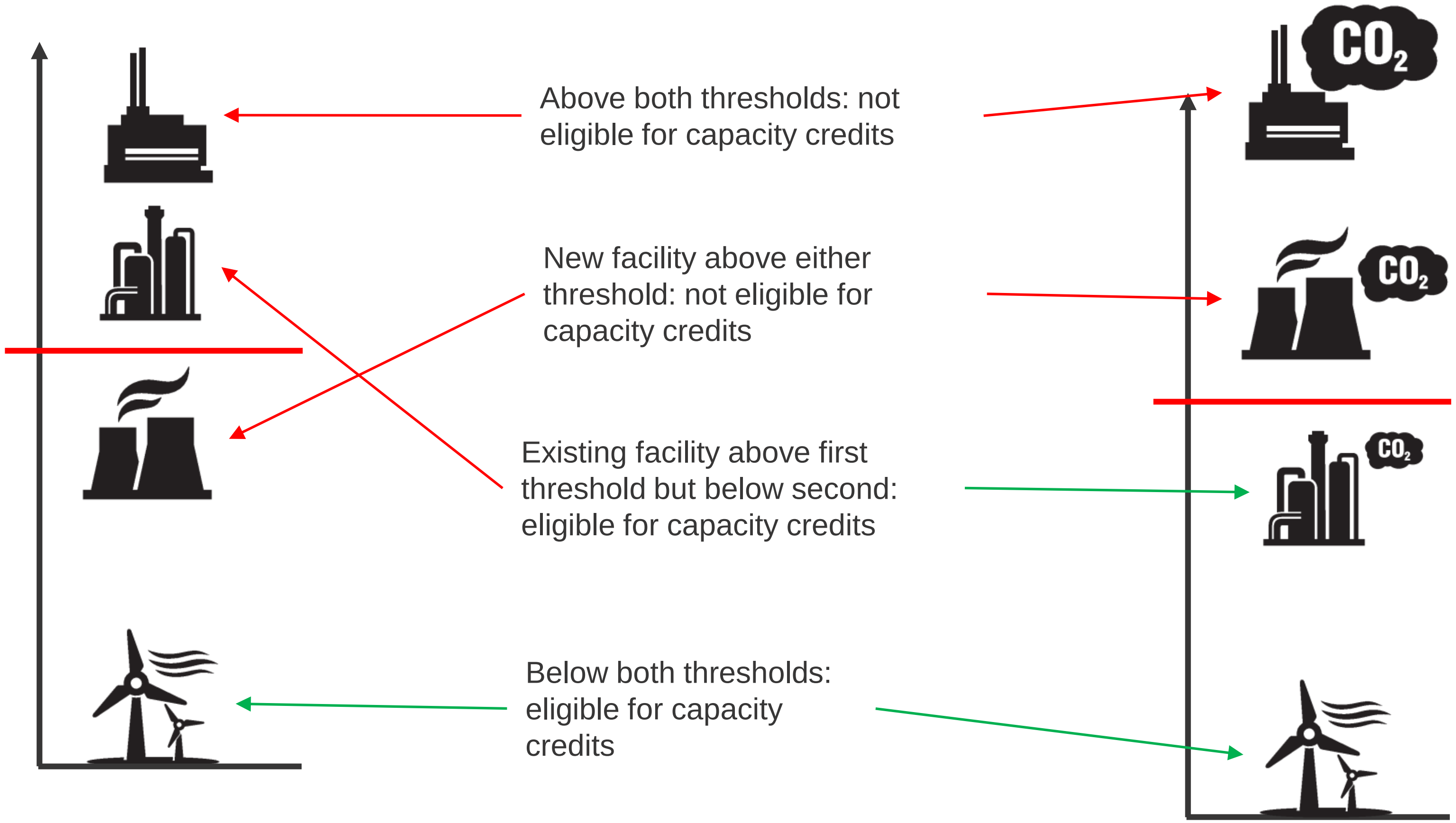
Facility emission rate (tCO2e/MWh)

Facility total annual emissions (tCO2e)



For each capacity year

Option 6 (part 2)



For each capacity year

Threshold 1: Facility emission rate (tCO2e/MWh)

Threshold 2: Facility total annual emissions (tCO2e)

Common Parameters

- All options will require AEMO to determine emission intensity parameters for each facility. EPWA proposes these will be set by:
  - Determining an emissions content value for each type of fuel
  - Determining facility-specific heat rates
  - Accounting for generation used to self supply on-site load
  - Accounting for cogeneration production of heat energy
  - Combining these factors to determine a tCO_2e/MWh emissions factor for each facility
- Options 1, 2 and 4 would require Government to determine the carbon penalty rate to be applied
- Option 6 would require Government to determine an emissions threshold value or values
- The specific method used will be based on existing methodologies as far as possible, and tie in with assumptions made for other WEM processes that consider emissions, such as the WOSP
- The penalty regime could be phased in over a number of years, but an appropriate starting penalty rate or threshold, or the appropriate trajectory over time has not yet been determined.

Assessment

Criteria for Assessment of the Identified Options

The six options were then assessed against the following criteria:

1. Actual penalty imposed on high-emission technologies
2. Implemented through the WEM
3. Net zero cost impact on consumers
4. Power system security and reliability are not compromised
5. Simple and low-cost implementation
6. The accumulated penalties incentivise firming solutions to facilitate the growth in renewable intermittent generation

Analysis – Policy Criteria

	Penalty on high emissions	WEM	Cost impact on consumers	Security and reliability	Simple implementation	Penalties can fund firming
Option 1	●	●	◑	◕	◕	◔
Option 2	●	●	◑	◕	◕	◔
Option 4	◑	●	◑	◑	◕	◑
Option 5	●	○	◑	◕	◑	◔
Option 6	●	●	◕	◕	●	○

See appendix for brief discussion of assessment. More filled quadrants = better performance.

Shortlisted Options

Two options (with preference for Option 6) shortlisted by the RCM Review Working Group for more analysis:

- Option 1 – penalty per MWh, charged in settlement by interval
  - Has the potential to collect penalties for distribution as support payments for long term storage
  - Is preferred to option 2 as it provides greater granularity for penalty calculation
- Option 6 – emissions threshold for RCM participation
  - Has more certainty regarding reliability of supply than option 1 (timing of exit is likely to be clearer), requires less effort and is simpler to implement.
  - Would avoid penalising high emissions plant that receives RCM revenues but rarely runs
  - Does not collect funds for distribution (so would need to be supported by other mechanisms to encourage entry of clean firming capacity), but more clearly avoids penalty costs passing to consumers

Both options

- Have penalties relating to actual emissions
- Are implemented through the WEM and are relatively simple to implement
- Could be phased in with the penalty rate (Option 1) or threshold (Option 6) becoming more stringent over time
- Do not penalize biogas/biomass facilities as their emissions are not of fossil fuel origin

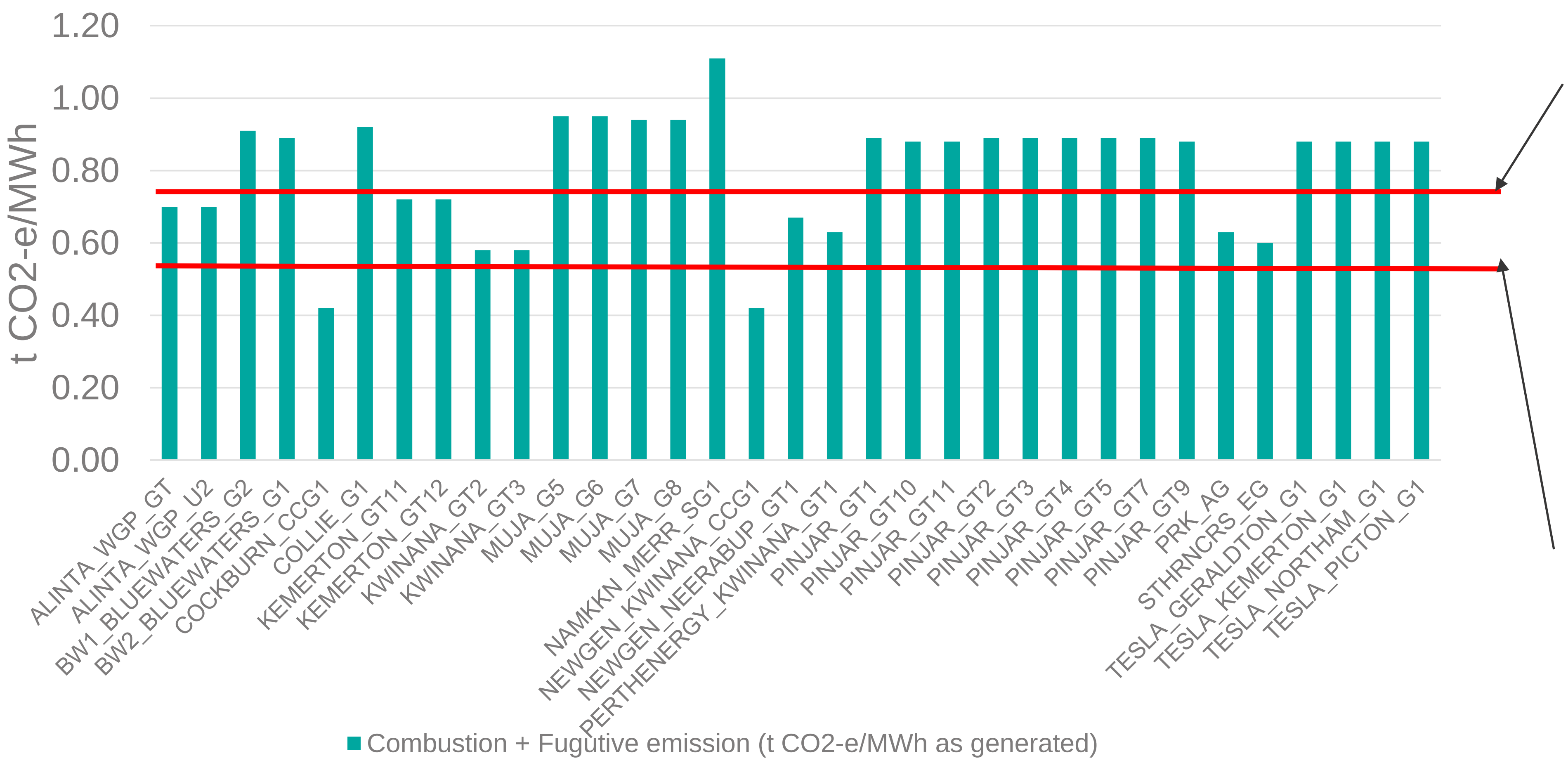
EPWA estimated emissions penalties for existing and generic new facilities (see next slides)

Option 6 - Facility Emission Rates (tCO2e/MWh)

Sources:

This slide shows the application of the first threshold – inherent emissions intensity per MWh produced.

- WOSP 2021
- Carbon Emissions Limits in the Capacity Market – Guidance



A suitable threshold would need to be determined e.g. an initial threshold of 0.75 tCO2e of Fossil Fuel origin per MWh of electricity generated

UK limit: 0.55 tCO2e of Fossil Fuel origin per MWh of electricity generated

Not feasible as starting value for WEM penalty, as it would risk system reliability

Biogas/biomass not penalized as not fossil fuel derived

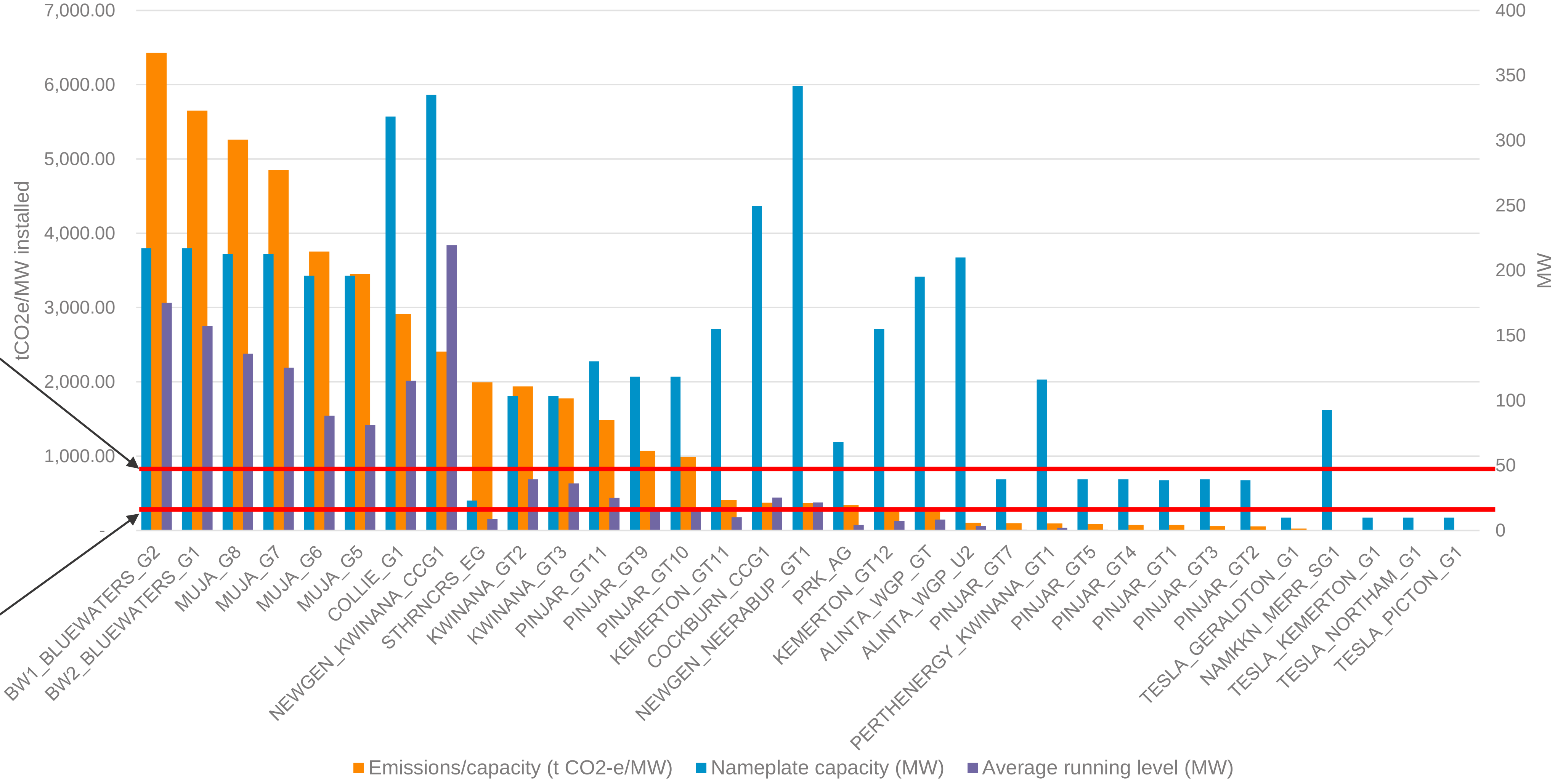
Option 6 - Facility Emission Rates per MW Installed

This slide shows the application of the second threshold – total emissions per MW of installed capacity.

A suitable threshold would need to be determined so as not to endanger system reliability

UK limit – 350 tCO2e/MW

Not feasible as starting value for WEM penalty, as it may risk system reliability

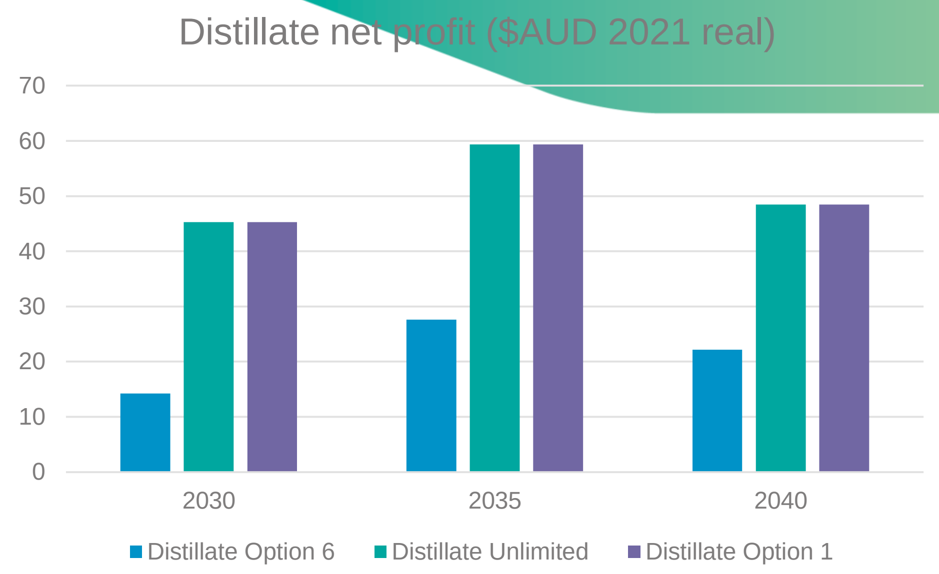


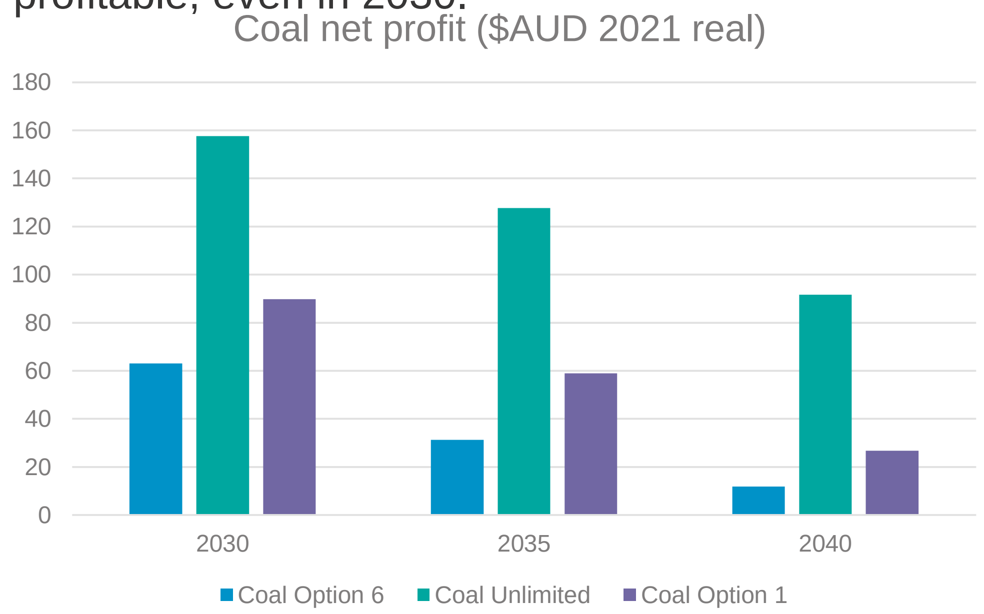
Working together for a brighter energy future.

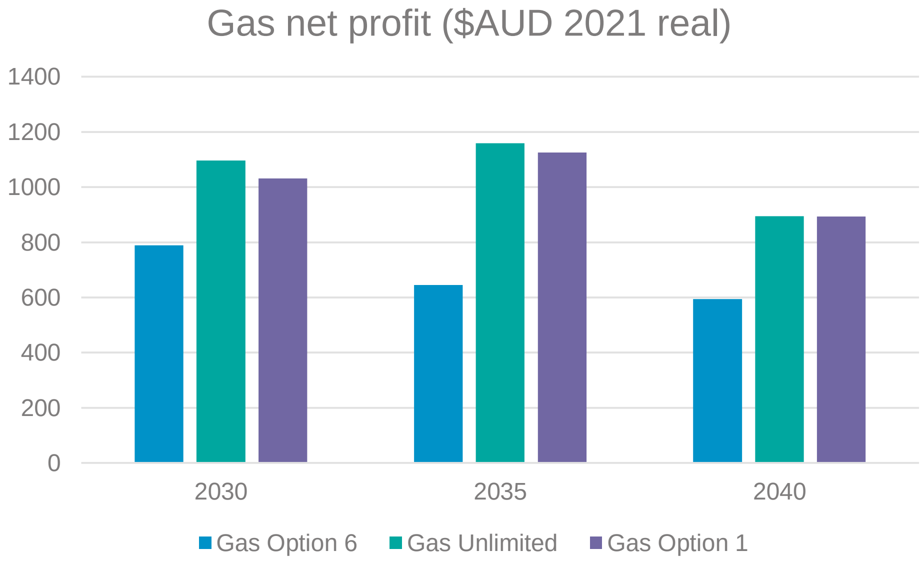
Low Price Scenario: Both Emissions Limits

Under a low price scenario (based on the expected levels of intermittent renewable entry), and assuming fuel availability, existing coal facilities would remain profitable until around 2040, even when ineligible for capacity payments. Gas and distillate facilities remain profitable, but are more affected by option 6 (thresholds at 0.75T/MWh and 350T/MW) than option 1 (penalty rate at $25/TCO2e).

Profitability is dependent on ESS revenue, and a coal fired facility without either capacity or ESS revenue would not be profitable, even in 2030.



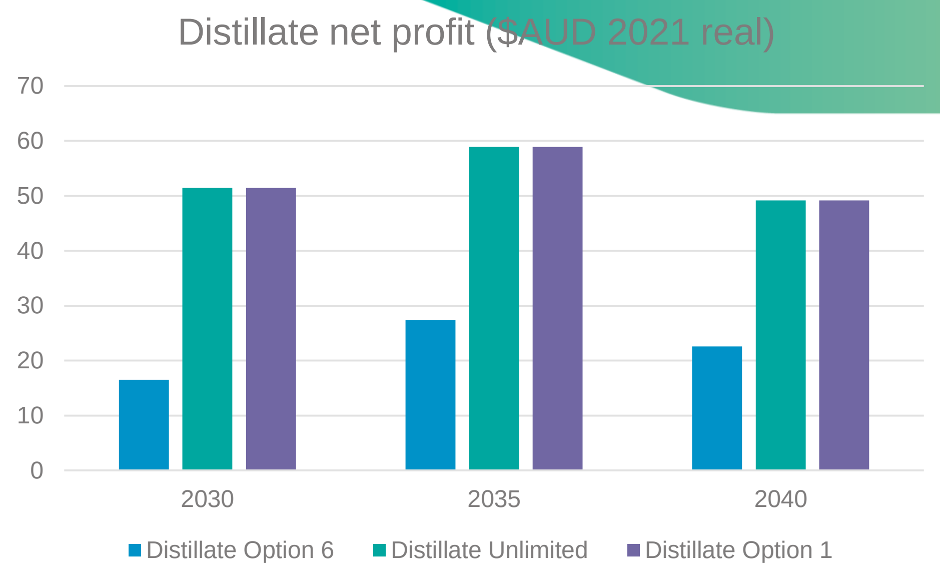


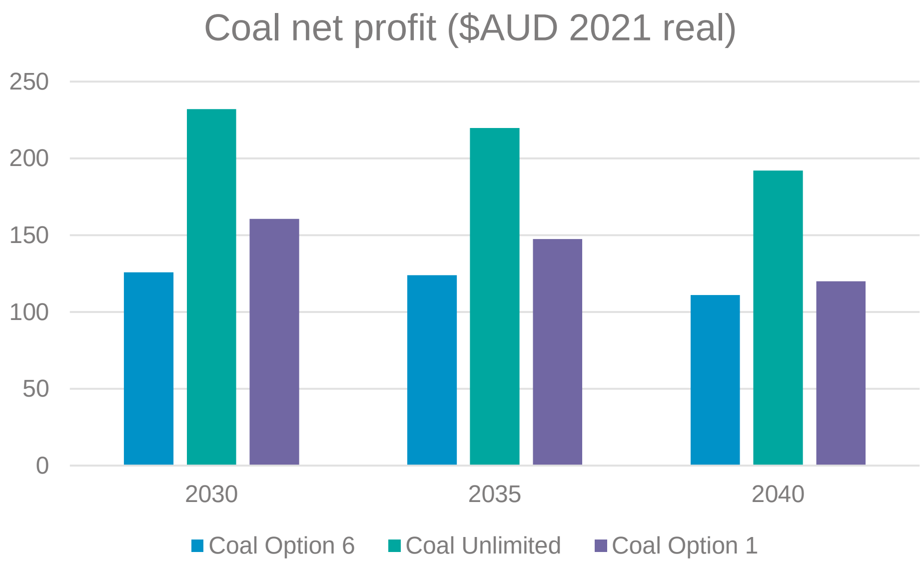


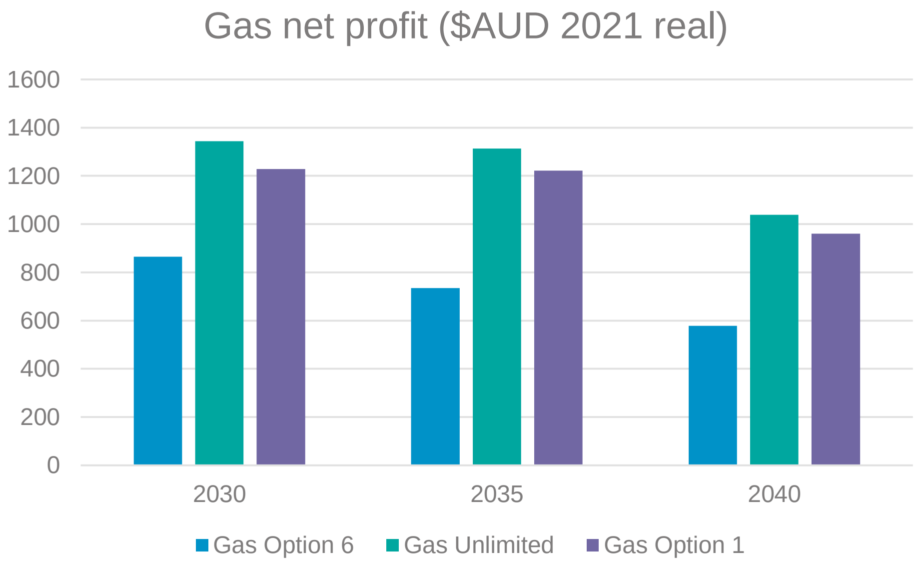
High Price Scenario: Both Emission Limits

Under a high price scenario (driven by slower entry of intermittent renewables), there is sufficient non-capacity revenue for existing facilities to cover their operating costs, and hence (assuming fuel availability) retirement would be driven primarily by facility technical lifespan.

Gas and distillate facilities are heavily affected by option 6, but only minimally by option 1.







Analysis – Option 1 vs Option 6

Coal and Distillate

Facility Code	Fuel	Combustion + Fugutive emission (t CO2-e/MWh as generated)	Emissions/capacity (t CO2-e/MW)	550g of CO2 of Fossil Fuel origin per kWh of electricity generated	350 kg CO2 of Fossil Fuel origin on average per year per installed kWe	Reserve capacity revenue 2021-22 CY (AUD)	Penalty amount (25 AUD/t C02-e)	Penalty amount (100 AUD/t C02-e)2
BW1_BLUEWATERS_G2	Black coal	0.91	6,428.45	x	x	$17,050,413	$34,874,315	$139,497,260
BW2_BLUEWATERS_G1	Black coal	0.89	5,650.10	x	x	$17,050,413	$30,651,778	$122,607,113
MUJA_G8	Black Coal	0.94	5,259.11	x	x	$16,578,973	$27,952,168	$111,808,671
MUJA_G7	Black Coal	0.94	4,849.92	x	x	$16,578,973	$25,777,349	$103,109,395
COLLIE_G1	Black coal	0.92	2,913.29	x	x	$24,923,460	$23,182,478	$92,729,914
MUJA_G6	Black Coal	0.95	3,752.47	x	x	$15,164,653	$18,368,343	$73,473,372
MUJA_G5	Black Coal	0.95	3,448.13	x	x	$15,321,799	$16,878,585	$ 67,514,341
NAMKKN_MERR_SG1	Distillate	1.11	4.13	x	✓	$6,443,013	$9,553	$38,213
TESLA_GERALDTON_G1	Distillate	0.88	24.63	x	✓	$777,876	$6,096	$ 24,382
TESLA_KEMERTON_G1	Distillate	0.88	3.06	x	✓	$777,876	$ 757	$3,029
TESLA_NORTHAM_G1	Distillate	0.88	1.40	x	✓	$777,876	$347	$1,388
TESLA_PICTON_G1	Distillate	0.88	0.03	x	✓	$777,876	$7	$26

An option 1 penalty rate of $25/tCO2e has a similar effect on coal plant as not receiving capacity credits under option 6. Cogeneration plant has not been assessed because available emissions figures do not account for non-electric energy production.

Facility Code	Fuel	Combustion + Fugutive emission (t CO2-e/MWh as generated)	Emissions/capacity (t CO2-e/MW)	550g of CO2 of Fossil Fuel origin per kWh of electricity generated	350 kg CO2 of Fossil Fuel origin on average per year per installed kWe	Reserve capacity revenue 2021-22 CY (AUD)	Penalty amount (25 AUD/t C02-e)	Penalty amount (100 AUD/t C02-e)2
NEWGEN_KWINANA_CCG1	Natural gas	0.42	2,408.18	✓	x	$25,756,338	$20,168,476	$80,673,904
KWINANA_GT2	Natural gas	0.58	1,938.76	x	x	$7,739,473	$5,002,005	$20,008,020
PINJAR_GT11	Natural gas	0.88	1,488.75	x	x	$9,743,093	$4,838,449	$19,353,797
KWINANA_GT3	Natural gas	0.58	1,776.93	x	x	$7,794,474	$4,584,486	$18,337,943
PINJAR_GT9	Natural gas	0.88	1,073.14	x	x	$8,721,640	$3,171,140	$12,684,562
NEWGEN_NEERABUP_GT1	Natural gas	0.67	367.35	x	x	$25,976,343	$3,140,828	$12,563,312
PINJAR_GT10	Natural gas	0.88	987.91	x	x	$8,721,640	$2,919,260	$11,677,039
COCKBURN_CCG1	Natural gas	0.42	372.54	✓	x	$18,857,599	$2,325,584	$9,302,335
KEMERTON_GT11	Natural gas	0.72	409.16	x	x	$12,178,866	$1,585,489	$6,341,956
ALINTA_WGP_GT	Natural gas	0.7	263.57	x	✓	$15,400,373	$1,286,211	$5,144,842
STHRNCRS_EG	Natural gas	0.6	1,993.53	x	x	$1,571,467	$1,146,279	$4,585,116
KEMERTON_GT12	Natural gas	0.72	291.29	x	✓	$12,178,866	$1,128,746	$4,514,984
PRK_AG	Natural gas	0.63	341.43	x	✓	$4,667,256	$ 580,439	$2,321,756
ALINTA_WGP_U2	Natural gas	0.7	101.92	x	✓	$15,400,373	$535,057	$2,140,226
PERTHENERGY_KWINANA_GT1	Natural gas	0.63	92.30	x	✓	$8,564,493	$267,681	$1,070,725
PINJAR_GT7	Natural gas	0.89	96.15	x	✓	$2,867,927	$94,470	$377,882
PINJAR_GT5	Natural gas	0.89	83.71	x	✓	$2,907,213	$82,242	$328,967
PINJAR_GT4	Natural gas	0.89	74.77	x	✓	$2,907,213	$73,460	$293,841
PINJAR_GT1	Natural gas	0.89	74.30	x	✓	$2,441,431	$71,516	$286,064
PINJAR_GT3	Natural gas	0.89	55.99	x	✓	$2,907,213	$55,012	$220,049
PINJAR_GT2	Natural gas	0.89	55.59	x	✓	$2,380,772	$53,509	$214,035

Incentives for Replacement Clean Firming

Both option 1 and option 6 provide financial pressure for high emission generators to reduce their output or retire. This has two effects:

- Increasing the amount of new capacity required to meet the reserve capacity target
- Increasing the service duration required from storage facilities

The market needs developers to fill the gap, and if they do not, it needs AEMO to procure additional capacity.

Market activity will only fill the gap where revenues are reasonably predictable, and penalty payments are unlikely to be so. This indicates that other incentives for new entry are likely to be more important:

- Incentives for flexible capacity: i.e. the new capacity product to be introduced as signalled
- Incentives for longer term storage: i.e. the availability duration gap to be incorporated into CRC analysis as signalled
- The capacity price: The current maximum price level of 1.3 * CONE needs to be examined to assess whether it is sufficient in a capacity shortage situation

Guidance and Next Steps

RCMRWG recommendations

The RCMRWG agreed that it was appropriate to shortlist options 1 and 6 for additional work.

While there is little to separate options 1 and 2, the group felt that it would be useful to allocate penalties on the shortest reasonable time interval and so preferred option 1.

The group agreed that while no penalties would be collected under option 6, the uncertainty of available revenue under other options (because they are dependent on retirement and operational decisions) means that *all* options need to be supported by careful consideration of other revenue streams to encourage entry of clean firming technology.

Next Steps

- Review emissions intensity figures for existing facilities to ensure accuracy
- Assess appropriate starting level and transition-in profile for penalty rate (option 1) or threshold (option 6)
- Assess revenue sufficiency for new technologies (particularly long-term storage and capacity price level under shortfall conditions)
- Present options with analysis to Minister

Questions for the MAC

1. Does MAC agree that it is appropriate to shortlist option 1 and option 6?
2. Does MAC have a preference for either option and if so why?
3. Does MAC agree with the proposed next steps?

We're working for Western Australia.

Appendix – Description of Options

Option 1 – Penalty on Trading Interval Emissions

- For each facility, determine:
  - emissions in each trading interval (tCO_2e) as:

    *facility generation (in MWh) * facility emissions rate*
  - Interval emissions penalty ($) as:

    *facility emissions * penalty rate*
- Penalties would be applied as a separate settlement segment.
- Penalties would apply to all facilities with non-zero emissions.
- Participants would be precluded from including penalties in their energy offers.

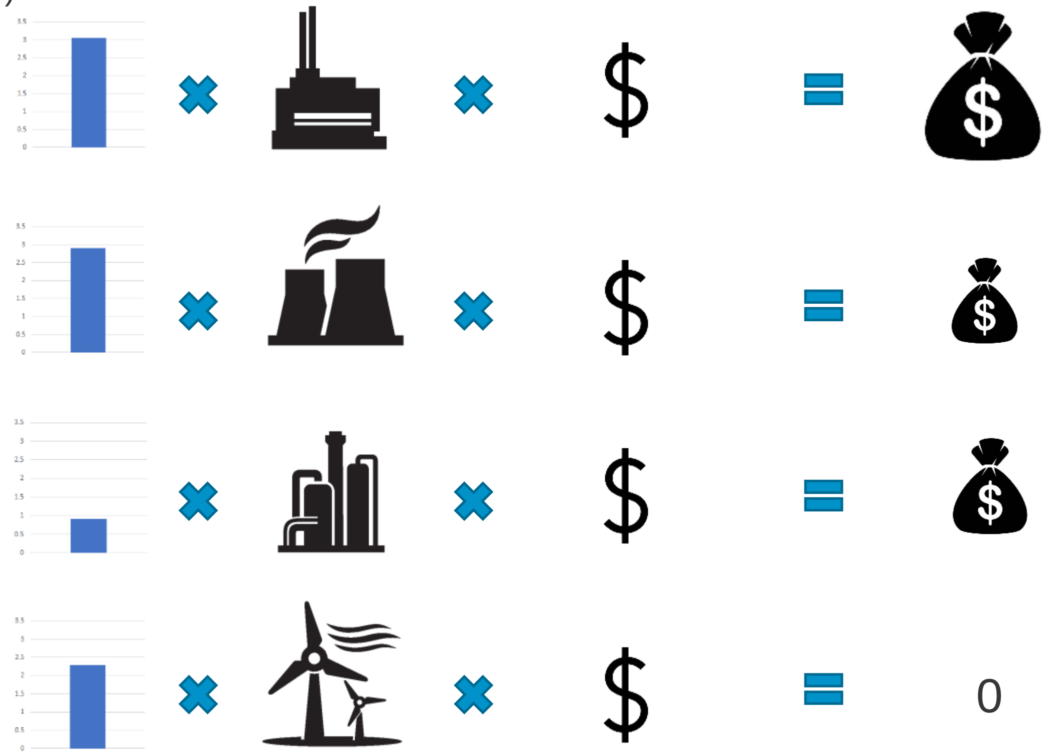
Option 1

Current interval facility generation (MWh)

Facility emission rate (tCO2e/MWh)

Penalty rate ($/tCO2e)

Penalty amount ($)



For each trading interval

Option 2 – Penalty on Settlement Period Emissions

- For each facility:
  - determine facility emissions (tCO2e) in settlement period as:

    *facility generation * facility emissions rate*
  - Settlement period emissions penalty ($) as:

    *facility emissions * penalty rate*
- Penalties would be applied as a separate settlement segment.
- Penalties would apply to all facilities with non-zero emissions.
- Participants would be precluded from including penalties in their energy offers.

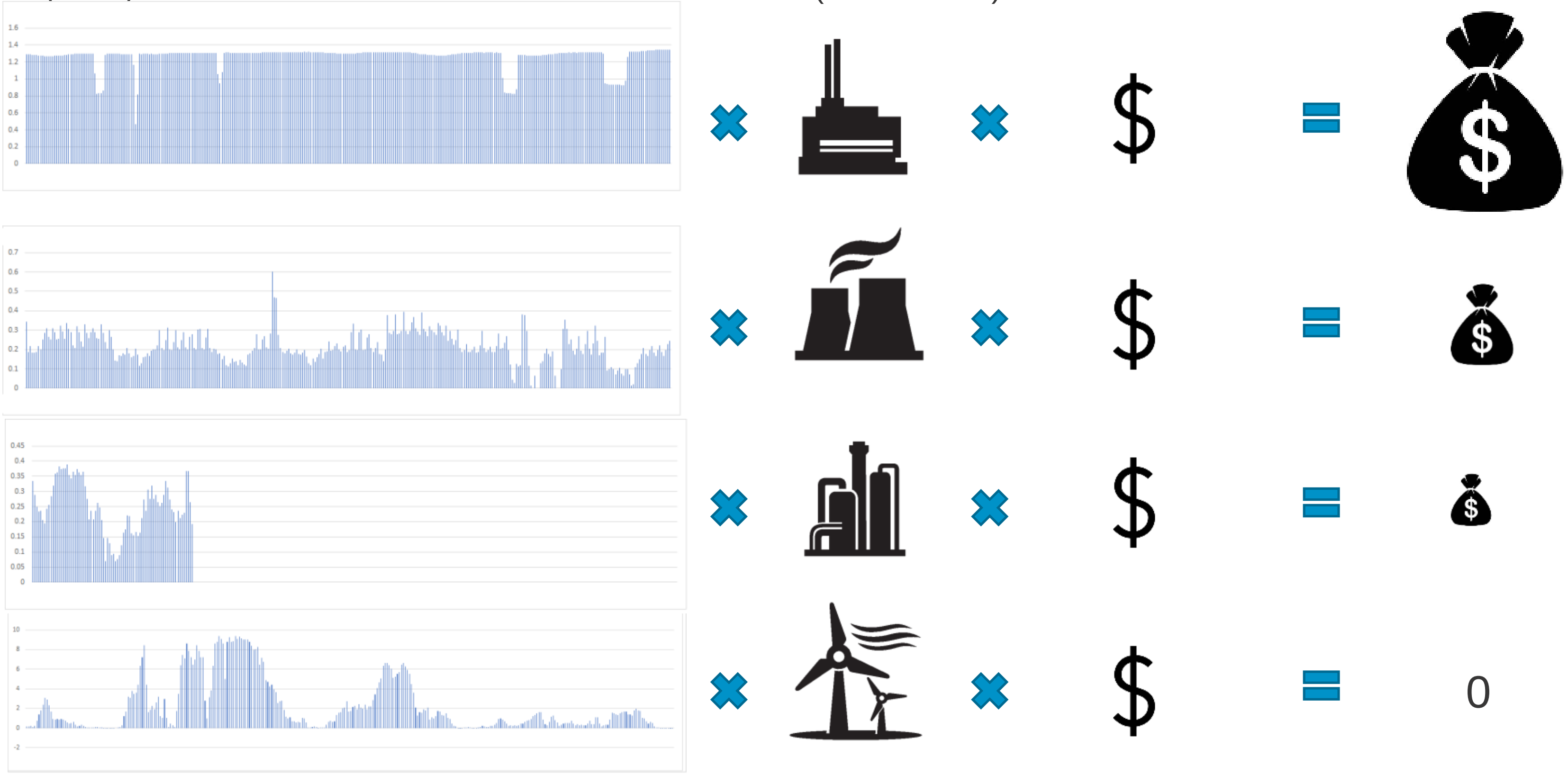
Option 2

Previous settlement week facility generation (MWh)

Facility emission rate (tCO2e/MWh)

Penalty rate ($/tCO2e)

Penalty amount ($)



For each trading week

Option 3 – RCM Penalty on Historic Emissions

For each facility:

- determine facility emissions in previous capacity year or years (tCO2e) as:

    *facility generation * facility emissions rate / number of years*

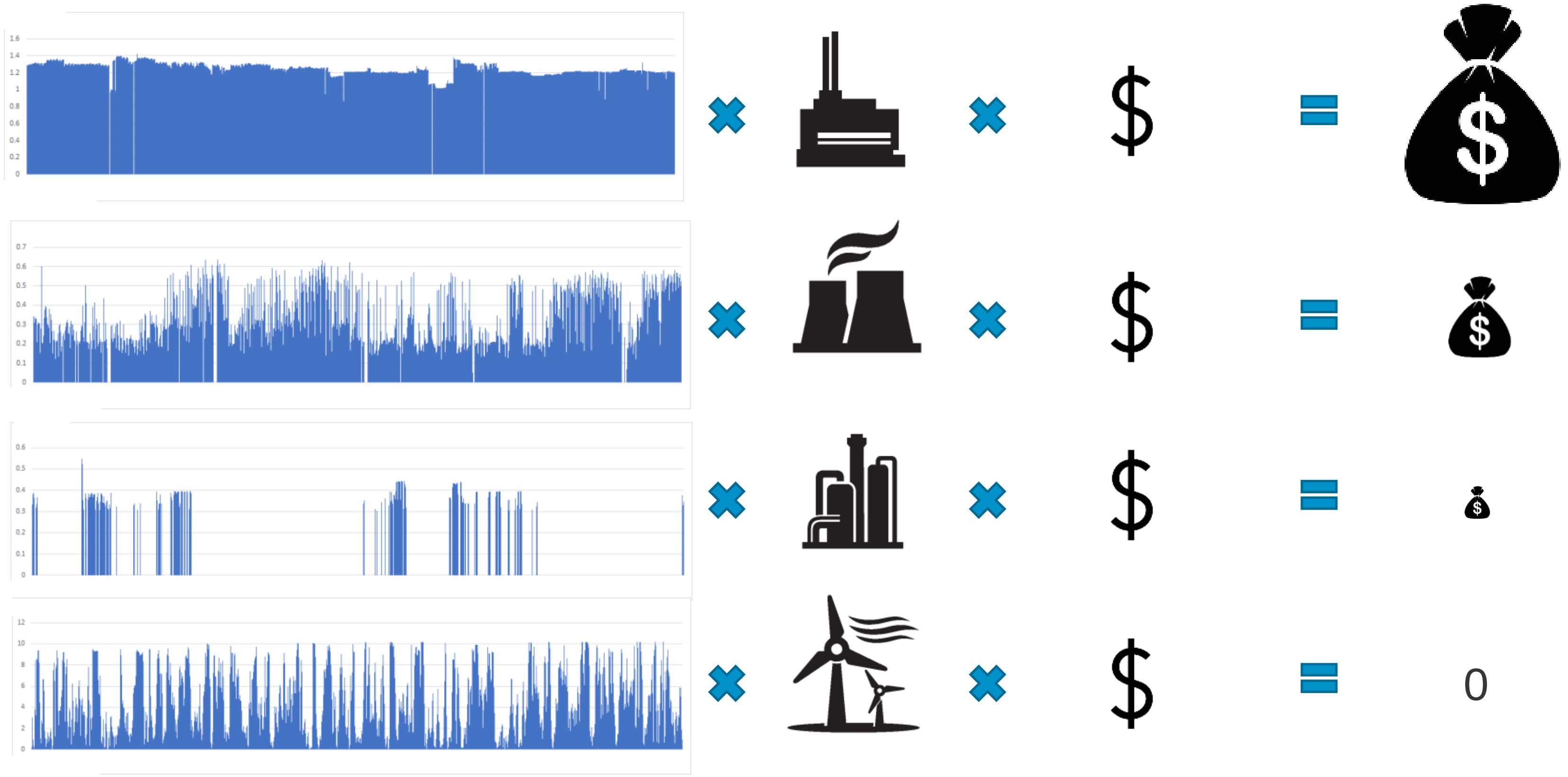
- determine facility penalty amount ($) as:

    *facility emissions * penalty rate*

- Penalties would be applied as a separate settlement segment.
- Penalties would apply to all facilities with non-zero emissions.
- Participants would be precluded from including penalties in their energy offers.

Option 3

Previous capacity year facility generation (MWh) | Facility emission rate (tCO_2e/MWh) | Penalty rate (\$/tCO_2e) | Penalty amount (\$)



For each capacity year

Option 4 – RCM Penalty on Theoretical Maximum Emissions

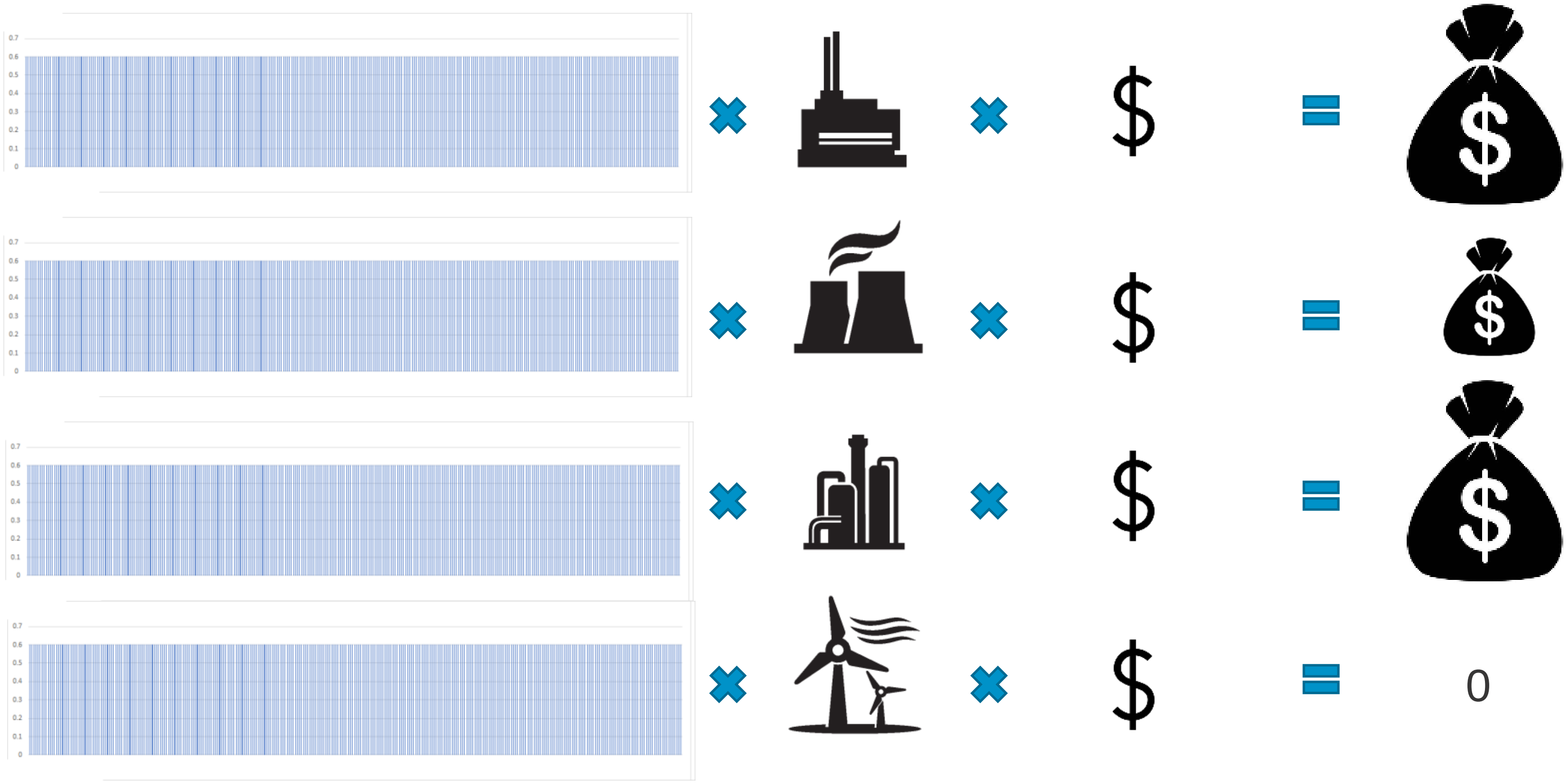
- For each facility, determine:
    - the maximum possible emissions (tCO_2e) as:

      *facility nameplate capacity * facility emissions rate * hours in year*
    - annual emissions penalty ($) as:

      *facility emissions * penalty rate*
- Penalties would be applied as a separate settlement segment.
- Penalties would apply to all facilities with non-zero emissions.
- Participants would be precluded from including penalties in their energy offers.

Option 4

Facility maximum generation potential (MWh) | Facility emission rate (tCO2e/MWh) | Penalty rate ($/tCO2e) | Penalty amount ($)



For each settlement week

Option 5 – Penalty Implemented through ACCUs or LGCs

- For each facility:
  - determine facility emissions (tCO2e) in the settlement period as:

    *facility generation * facility emissions rate*

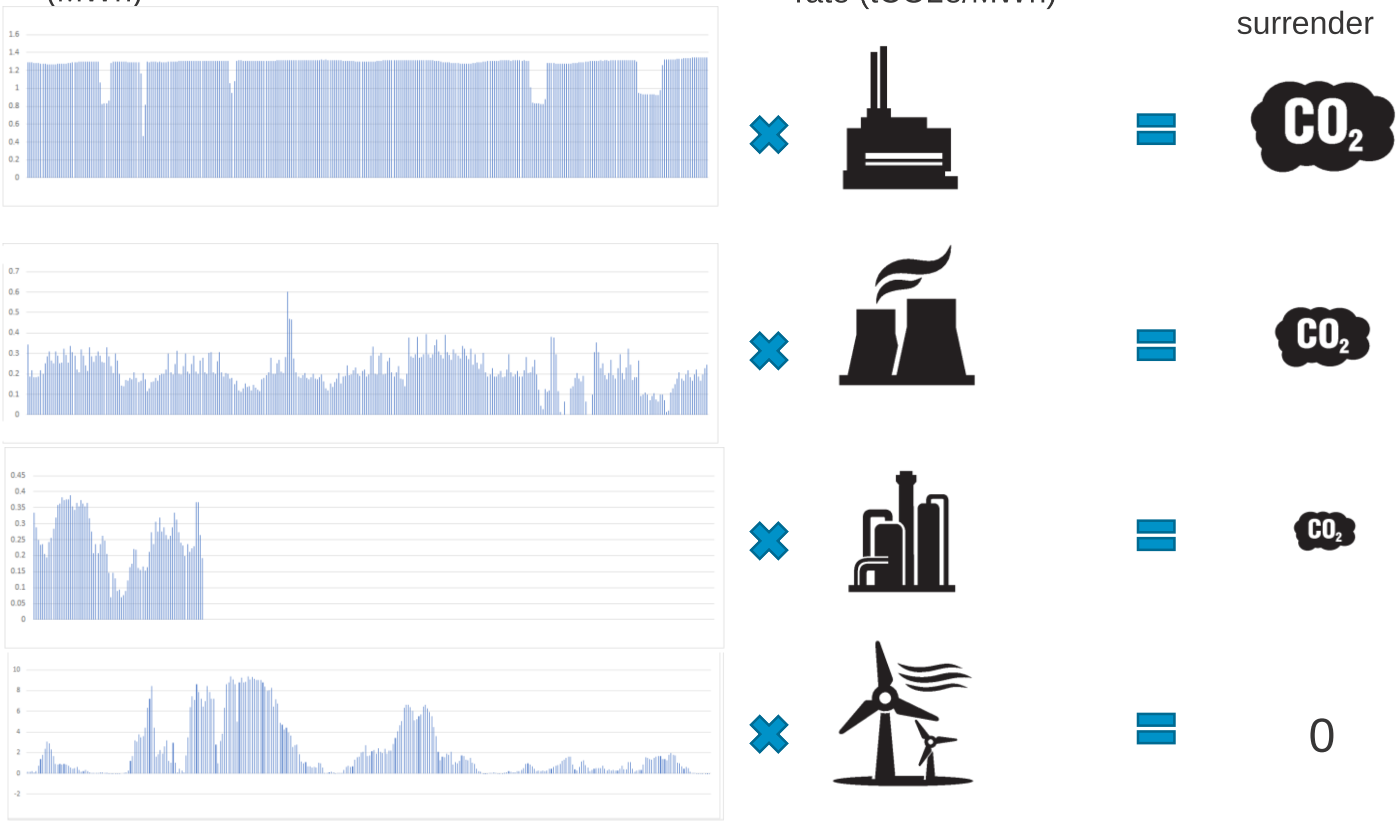
  - require owner to surrender ACCUs equal to facility emissions to AEMO
- Penalties would be applied outside WEM settlement
- Penalties would apply to all facilities with non-zero emissions
- Participants would be precluded from including cost of ACCUs in their energy offers

Option 5

Previous settlement week facility generation (MWh)

Facility emission rate (tCO2e/MWh)

Quantity of ACCUs to surrender



For each trading week

Option 6 – Emissions Threshold for RCM Participation

- Perform additional checks during CRC allocation for each facility:
  - Determine facility emissions (tCO_2e) in previous capacity year as:

    *facility generation * facility emissions rate*
  - Determine whether facility emissions intensity is below threshold:

    facility emissions rate ≤ rate threshold
  - Determine whether actual facility emissions are below threshold:

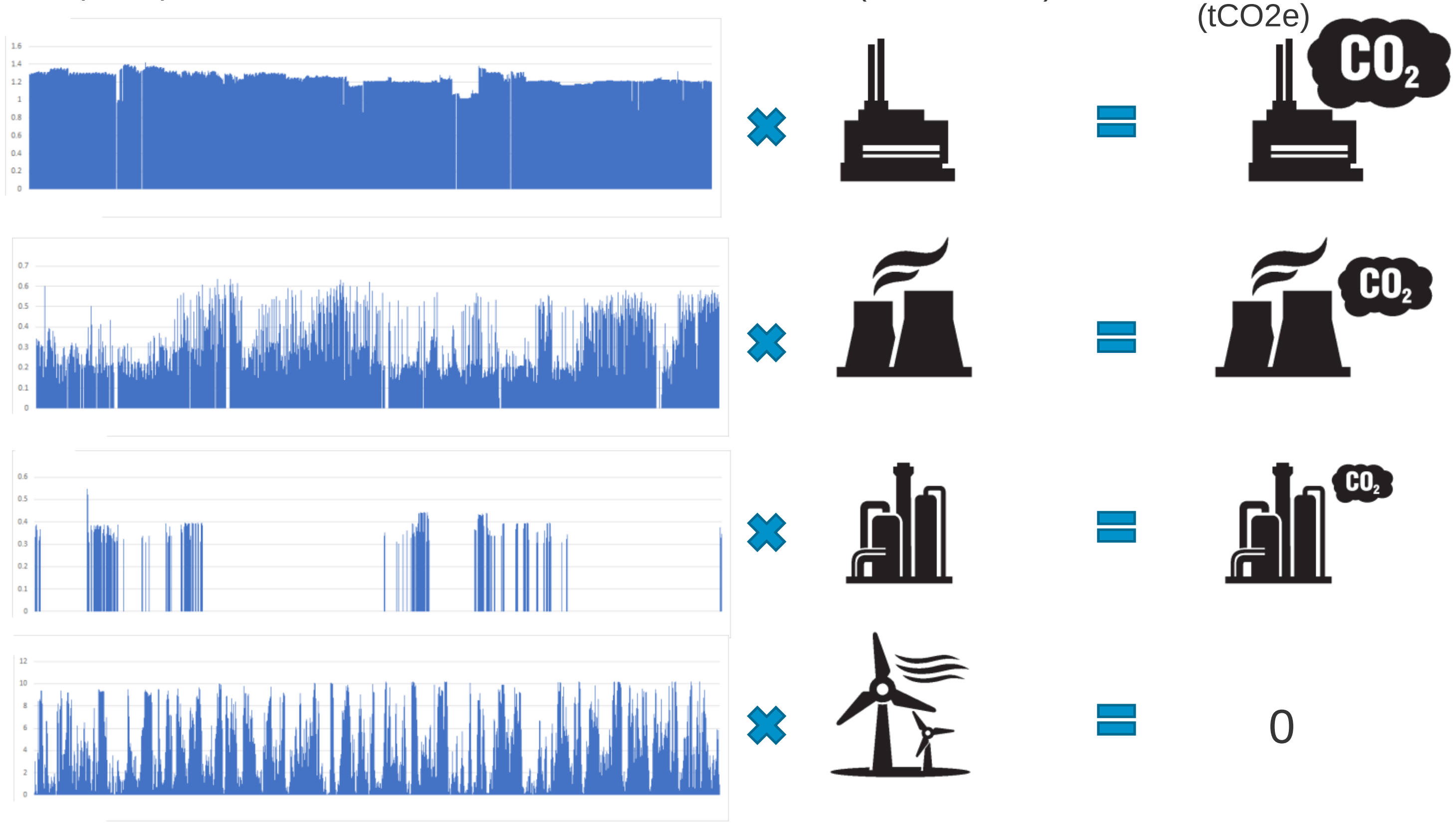
    facility emissions ≤ quantity threshold
- If facility is above either threshold, CRC = 0
- The thresholds would apply to all new facilities at implementation
- A higher threshold would be adopted for existing facilities, and ratcheted down over a five-year period
- This option would not collect any penalty funds for redistribution

Option 6 (part 1)

Previous capacity year facility generation (MWh)

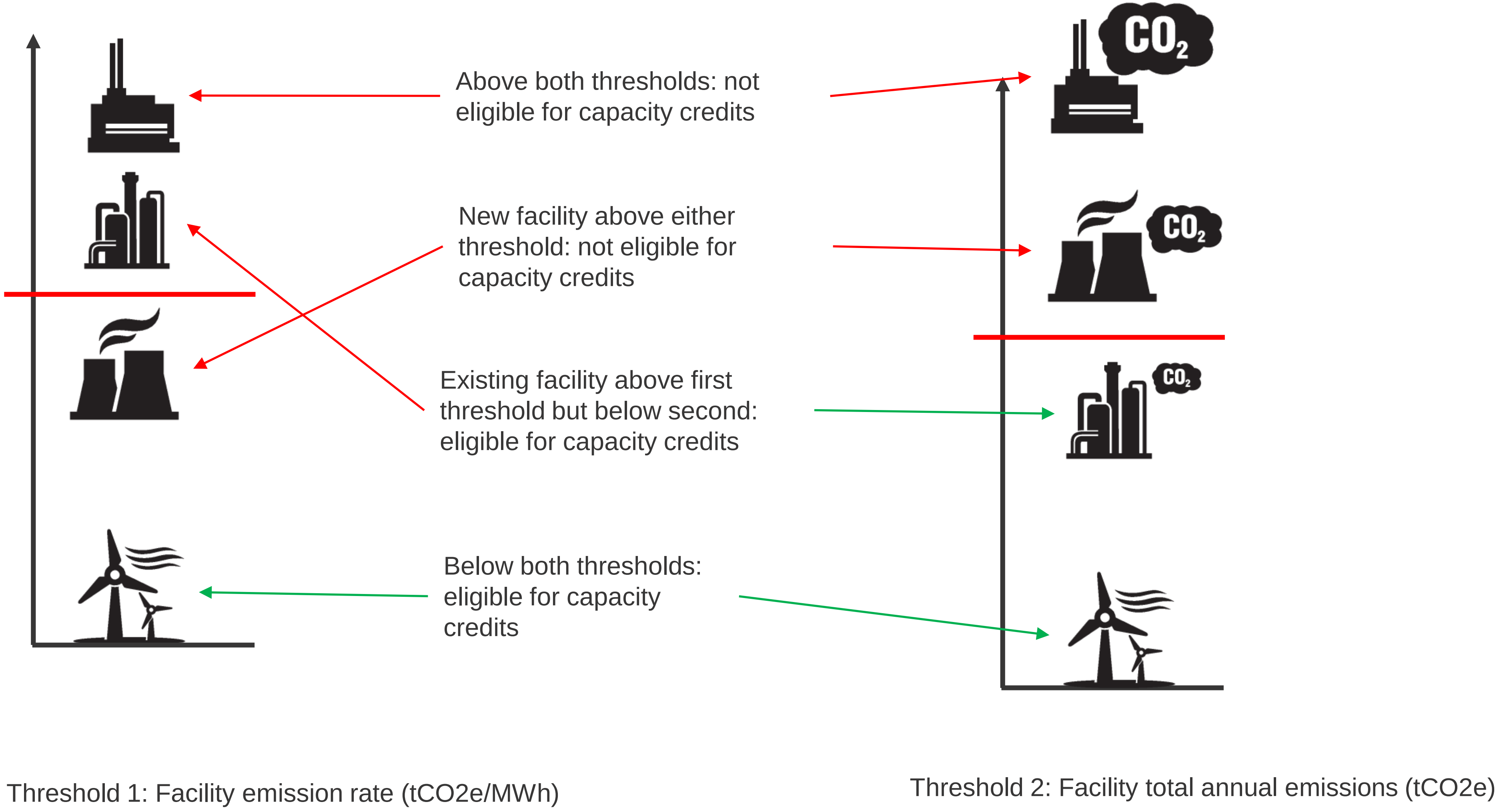
Facility emission rate (tCO2e/MWh)

Facility total annual emissions (tCO2e)



For each capacity year

Option 6 (part 2)



For each capacity year

Appendix – Analysis Against Criteria

Qualitative Analysis against Policy Criteria

1. **Penalty on high emissions**
   - Options 1, 2, 5, 6 have a penalty based on actual emissions
   - Option 4 has a penalty based on theoretical emissions, not actual emissions
2. **Implemented through the WEM**
   - Option 5 is not implemented through the WEM
3. **Cost impact on consumers**
   - At the margin, all options will drive earlier exit by high emission facilities, increasing the overall cost to consumers of energy supply (but decreasing the external costs of environmental impacts)
   - Options 1, 2, 4 and 5 all require additional measures to avoid participants passing increased operating costs through to consumers. Option 6 is simpler in that regard, as it does not change incentives for short run operating decisions

Qualitative Analysis against Policy Criteria

4. **Security and reliability**
   - All options are likely to bring forward exit of inflexible coal plant
   - Option 4 is also likely to bring forward exit of flexible gas plant
   - Option 6 provides most certainty regarding the need to procure additional capacity to fill in any gaps
5. **Simple implementation**
   - All options require new processes to determine facility emissions rates
   - Options 1, 2, 4 require new settlement products for collecting penalty payments
   - Option 5 requires new process infrastructure to collect and sell ACCUs rather than just using WEM processes
6. **Penalties can fund firming**
   - Options 1, 2, 4 and 5 would collect penalties, but they would only be available to new firming facilities as long as high emission facilities remain in the market and do not retire
   - The amount of revenue would not be known before real time, except under option 4, and could change at short notice as it is dependent on the operating patterns of high emission facilities
   - Option 6 would not collect penalties at all
   - None of the options would provide a solid revenue stream for new low-emission firming facilities

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_12_13

1. Purpose

To update the MAC on the progress of the Cost Allocation Review and seek feedback from the MAC on the proposals in the draft Consultation Paper for the Cost Allocation Review.

2. Recommendation

That the MAC:

(1) notes the minutes from the Cost Allocation Review Working Group (**CARWG**) meeting on 27 September 2022 (**Attachment 1**);

(2) notes the minutes from the CARWG meeting on 25 October 2022 (**Attachment 2**);

(3) reviews the proposals outlined in the draft Cost Allocation Review Consultation Paper (**Attachment 3**);

(4) provides views on the proposals and questions outlined in the draft consultation paper, which are also summarised for convenience in Table 1, and advises on the potential impacts of each of the proposals;

(5) notes the assessment of each proposal against the guiding principles for the Cost Allocation Review provided in Table 2; and

(6) notes that Energy Policy WA may make further editorial changes to the consultation paper before its publication, scheduled for 15 December 2022.

3. Background

At its meeting on 15 November 2022, the MAC endorsed:

- further consideration of the Tolerance Method (now referred to as Forecast Range Method) as an interim method to allocate Frequency Regulation costs in the Wholesale Electricity Market (**WEM**) in 2025, after commencement of the new market arrangements; and
- further assessment of the new NEM Causer-Pays Method to allocate Frequency Regulation costs in the WEM in 2027/28, after AEMO has implemented and operated the method for a period, for potential implementation in 2028/29.

AEMO, Marsden Jacob and Energy Policy WA met on 17 November 2022 to discuss the Forecast Range Method, including how it would work, the benefits it could deliver, and any potential implementation issues.

Following this meeting, Marsden Jacob and Energy Policy WA developed a new “WEM Deviation Method” to allocate Frequency Regulation costs in the WEM, which could be used for an interim period until the New NEM Causer-Pays Method has been implemented and operated for a period in the NEM.

The CARWG subsequently met on 29 November 2022. Minutes for this meeting may be tabled with the MAC once they have been approved by the CARWG, but papers for the meeting are available at CARWG 2022_11_29 - Combined Papers.pdf (www.wa.gov.au).

This CARWG meeting is summarised as follows:

- The CARWG considered the cost allocation methods that the MAC supported for further consideration.
- Regarding allocation of Frequency Regulation costs, the CARWG:
  - noted the concerns that Marsden Jacobs and Energy Policy WA had identified with the Forecast Ranges Method;
  - considered the new WEM Deviation Method (see section 5.5 of the draft consultation paper);
  - noted that system volatility is increasing significantly and that AEMO has indicated that it is important to implement a Causer-Pays mechanism to allocate Frequency Reserve costs to manage this;
  - endorsed that the consultation paper should:
    - recommend that a cost-benefit analysis of the New NEM Causer-Pays Method should be conducted in about 2027, after it has been operated in the NEM for a period, and that adoption of this method should be considered on the basis of this cost-benefit analysis; and
    - seek views on adopting the WEM Deviation Method to allocate Frequency Regulation costs in the interim period until the New NEM Causer-Pays Method is further assessed and potentially implemented.
- The CARWG considered a proposed Modified Runway Method to allocate Contingency Reserve Lower (**CRL**) costs (see section 7 of the draft consultation paper) and endorsed that the consultation paper should seek views on adopting this method.

4. Next Steps

• MAC to review a draft Consultation Paper	13 December 2022
• publish the Consultation Paper	15 December 2022
• submissions due on the Consultation Paper	9 February 2023
• MAC to review a draft Information Paper	16 March 2023
• publish the Information Paper	April 2023
• draft any resulting WEM Amending Rules and consult with the CARWG and the MAC	May-June 2023

5. Attachments

(1) draft minutes of CARWG 2022_09_27

(2) draft minutes of CARWG 2022_10_25

(3) draft Cost Allocation Review Consultation Paper

Table 1 – Rationale for the Design Proposals			
Conceptual Design Proposal		**Rationale**	**Consultation Question**
1. Market Fees			
No change	Retain the current method for allocating market services costs to Market Participants.	• While some of the identified options for allocating Market Fees may lead to a more equitable allocation of costs between Market Participants, changing the method is unlikely to change the Market Participants use of market services (i.e., no efficiency benefits) and there are likely to be material costs associated with implementing these options, so the costs would outweigh the benefits. AEMO would have to develop new systems and procedures to implement these options, and Market Participants would have to implement changes to their settlement and billing systems and make changes to their wholesale contracts. • Changing the Market Fee allocation method is a low priority relative to other reform initiatives to decarbonise the South West Interconnected System and maintain system reliability. • While there may be equity benefits to changing the Market Fee allocation method, changing the method would not increase the affordability, reliability, safety or security of supply and would provide no major identifiable benefit to Market Participants or end customers.	Do stakeholders support: (a) retaining the current method for allocating Market Fees to Market Participants; and (b) ignoring recharge energy when allocating Market Fees to storage facilities?

Table 1 – Rationale for the Design Proposals			
Conceptual Design Proposal		**Rationale**	**Consultation Question**
Rule clarification	Ignore recharge energy when allocating Market Fees to storage facilities.	• To avoid ‘double counting’ of Market Fees, storage facilities should be treated as a Market Generator (now termed a Market Participant in the WEM) and its recharge energy ignored for the purposes of Market Fee allocation.	
2. Frequency Regulation			
New method, subject to cost/benefit analysis	Implement the WEM Deviation Method to allocate Frequency Regulation costs in 2024/25, following the implementation of the new WEM arrangements on 1 October 2023, subject to a cost/benefit assessment.	• Simpler to implement when compared to other identified methods. • Provides incentives for Market Participants to minimise deviations in generation and loads, which has the potential to reduce Frequency Regulation requirements and costs. • Reduces incentives for ‘gaming’ by Market Participants to avoid Frequency Regulation charges. • Is more consistent with existing WEM frameworks (i.e., Primary Frequency Response, Tolerance Ranges and Frequency Control Essential System Services (**ESS**)). • Costs and timing for implementing this method is still under consideration.	Do stakeholders support: (a) adoption of the WEM Deviation Method in 2024/25 to allocate Frequency Regulation costs, subject to a cost/benefit analysis; and (b) reassessment of the New NEM Causer-Pays Method to allocate Frequency Regulation Costs in 2027, for potential implementation in 2028/29?

Table 1 – Rationale for the Design Proposals			
Conceptual Design Proposal		**Rationale**	**Consultation Question**
Further review in 2027	Reassess adoption of the new National Energy Market (**NEM**) Causer-Pays Method to allocate Frequency Regulation costs in 2027, for potential implementation in 2028/29.	• The new NEM Causer-Pays Method is still under development, has not been tested, and has unknown costs. • However, the new NEM Causers Pays Method will provide incentives for reducing Frequency Control requirements and costs and has the following potential benefits: ○ There are benefits for participants operating in both the WEM and NEM from having a common approach across the jurisdictions. ○ There will be cost savings for AEMO in developing and maintaining systems across both the NEM and WEM. ○ The new NEM Causer-Pays Method is easier to implement (although still significantly more complex than the WEM Deviation Method) compared to the current NEM Causer Pays Method. ○ The new NEM Causer Pays Method provides more frequent price signals (7-day settlement) to participants which allow them to adjust their forecasts or operations to minimise their net liability for Frequency Regulation costs.	

Table 1 – Rationale for the Design Proposals			
Conceptual Design Proposal		**Rationale**	**Consultation Question**
3. Contingency Reserve Raise			
Rule clarification	Application of the runway method should be adjusted to cater for situations where a Facility has multiple dispatchable units with separate network connections. In this situation, each separate dispatchable unit should be treated separately in the runway method (i.e. they should have separate FacilityMW for the purposes of Contingency Reserve Raises cost recovery).	• The method to allocate costs for Contingency Reserve Raise services is out of scope for this review. • However, to ensure consistency with the causer-pays principle, the Facility Risk Value used in the current runway method for cost allocation should be amended to consider lower risks from a generator configurations where the Facility has multiple dispatchable units with separate network configurations. Aggregating the dispatchable units in such circumstances would over-estimate their Facility Risk Value and over-recover Contingency Reserve Raise costs from the relevant Market Participant.	Do stakeholders support treating separately the units in a Facility for the purpose of calculating the Facility's Contingency Reserve Raise costs, where the units are separately dispatchable and have separate network connections?
4. Contingency Reserve Lower			
New method	Apply a modified runway method to allocate CRL costs. (1) If a Network Contingency sets the CRL requirement in a trading interval, the CLR costs are split into two components: (a) Facility CRL: • apply a runway method to allocate the Facility	• CRL is required to cover the risk of a material increase in system frequency due to a loss of single large load, or multiple loads on a single network element. • The requirement for CRL services is a function of the size of the load that may be lost, analogous to how the loss of the largest generator is the primary causer of Contingency Reserve Raise requirements. A modified	Do stakeholders support the proposal to allocate CRL costs to Loads using the proposed modified runway method?

Table 1 – Rationale for the Design Proposals		
Conceptual Design Proposal	**Rationale**	**Consultation Question**
component of CRL costs to Loads, treating all Loads with capacity less than or equal to 120 MW as if they were a single load; and • apply the existing method to allocate Facility CRL costs (pro-rata based on energy consumption) to Loads with capacity less than or equal to 120 MW. (b) Network CRL: • apply a runway method to allocate the network component of CRL costs to Loads in excess of 120 MW (noting that if there is only one large load in excess of 120 MW that sets the Network Contingency, then Facility will bear 100% of Network CRL costs). (2) If a Facility Contingency sets the CRL requirement in a trading interval, only use the Facility CRL cost allocation under step (1)(a).	runway method could be applied to allocate CRL costs to the largest loads operating in a trading interval – this would be consistent with the causer-pays principle and with Contingency Reserve Raise costs recovery. • This will be important given plans to build large battery energy storage systems (**BESS**) in the SWIS, which could substantially increase the CRL requirements and, under the causer-pays principle, the BESS should pay these additional costs. Using a modified runway method to allocate CRL costs should achieve this and give BESS developers an incentive to reduce the size of the dispatchable units to reduce their liability for these costs. • The CRL requirement can be due to a facility outage or a network outage. A large load or BESS locating in a less reliable part of the SWIS could increase the CRL requirement as it imposes both a Facility and Network Risk, and under a causer-pays principle, the costs associated with the higher CRL requirement should be allocated to the large load or BESS. The recommended modified runway method addresses network contingencies.	

Table 1 – Rationale for the Design Proposals			
Conceptual Design Proposal		**Rationale**	**Consultation Question**
5. System Restart			
No change	System Restart pricing is primarily focused on achieving cost recovery from beneficiaries, so the cost for System Restart services should be borne by loads, as per the current practice.	• The pricing of the System Restart service is primarily about cost recovery and is not directed at market efficiency. Therefore, the cost of System Restart services should be borne by loads.	Do stakeholders support retaining the current System Restart cost allocation method?
6. Non-Co-Optimised ESS (NCESS)			
No change	Recovery of NCESS should occur as follows: • where AEMO procures the NCESS, the NCESS costs should be allocated to beneficiaries of the services (Market Customers), given that the focus of NCESS charges is cost recovery and not market efficiency; and • where Western Power procures the NCESS, these services are a substitute for network investments, so it is appropriate for Western Power to recover these costs via network access charges.	• NCESS are typically locational services used to substitute for network upgrades. The causers of NCESS are both loads requiring power to be supplied and generators providing the power. • It is difficult to attribute NCESS costs to individual loads or generators, or to provide a sufficient price signal for customers and generators to relocate elsewhere on the system that does not require this service. As a result, the objective of NCESS pricing is cost recovery and the cost of NCESS should be borne by loads because there are no efficiency benefits with allocating this cost to generators or network service providers.	Do stakeholders support retaining the current NCESS cost allocation method and to review this once a number of NCESS has been procured?

Table 2 – Consistency with the Guiding Principles						
Guiding Principle	**Proposal 1 (Market Fees)**	**Proposal 2 (Frequency Regulation)**	**Proposal 3 (Contingency Reserve Raise)**	**Proposal 4 (Contingency Reserve Lower)**	**Proposal 5 (System Restart)**	**Proposal 6 (NCESS)**
(1) Meet the Wholesale Market Objectives	✓	✓	✓	✓	✓	✓
(2) Be						
• cost-effective	✓	✓	✓	**TBD**	✓	✓
• simple	✓	✓	✓	–	✓	✓
• flexible	–	–	✓	✓	✓	✓
• sustainable	–	–	✓	✓	✓	✓
• practical	✓	✓	✓	✓	✓	✓
• fair.	–	✓	✓	✓	✓	✓
(3) Provide effective incentives to Market Participants to operate efficiently to minimise the overall cost to consumers.	–	✓	✓	✓	–	–
(4) Use the causer-pays principle, where practicable and efficient	✓	✓	✓	✓	–	–

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

Minutes

Meeting Title:	Cost Allocation Review Working Group (**CARWG**)
Date:	27 September 2022
Time:	1:00pm – 3:00pm
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	
Jason Froud	Synergy	
Genevieve Teo	Synergy	
Paul Arias	Shell Energy	
Edwin Ong	AEMO	
Cameron Parrotte	Woodside	
Grant Draper	Marsden Jacob Associates (**MJA**)	
Peter McKenzie	MJA	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Shelley Worthington	EPWA	

Apologies	From	Comment
Tom Frood	Bright Energy	

Item	Subject	Action
1	**Welcome and Agenda** The Chair opened the meeting at 1:00pm.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	

Item	Subject	Action
3	**Minutes of CARWG Meeting 2022_08_30** Draft minutes of the CARWG meeting held on 30 August 2022 were distributed in the meeting papers on 21 September 2022. The Chair noted Mr Froud was not listed as attending the 30 August 2022 meeting but attended the meeting until 2:00pm. The CARWG accepted the minutes as a true and accurate record of the meeting. **Action: CARWG Secretariat to publish the minutes of the 30 August 2022 CARWG meeting on the CARWG web page as final.**	**CARWG Secretariat (28/09/2022)**
4	**Action Items** The action items were taken as read.	
5	**Assessment of Cost Recovery Options** Mr Draper restated the objectives and guiding principles for the review and the priority for the assessment of services, and provided a summary of the timeline for the review.	
	5(a) Allocation of Market Fees Mr Draper noted the CARWG had given the assessment of the allocation of Market Fees a high priority. Mr Draper noted that the following methods were reviewed (slide 6): • the current Wholesale Electricity Market (**WEM**) Method; • the current National Energy Market (**NEM**) Method; • a WEM Hybrid Method; and • Market Customers Only Method. Ms White asked how capacity was defined with regard to Market Participants selling WEM services. • Mr Draper replied that it was the maximum sent out capacity of the generators, as recorded in standing data. Ms White noted that, under the proposed WEM Hybrid Method, capacity for Market Generators is based on sent out standing data, which is substantially higher than the Capacity Credit allocation for intermittent generators, but is based on Individual Reserve Capacity Requirement (**IRCR**) for Market Customers, which has more to do with the peak. Ms White sought clarity on the rationale for the different approaches. • Mr Draper replied that the approach for Market Generators is based on the approach in the NEM, and is based on IRCR for Market Customers because there	

Item	Subject	Action
	is no alternative measure to use. There was no equivalent measure compared to total sent out from generation. • Ms White sought to understand the drivers of AEMO's costs, and noted that she could see the logic for using IRCR and for AEMO having to take action to manage the system, but asked why Capacity Credits allocated to Market Generators was not considered as it is the equivalent of IRCR. • Mr Draper noted that sent out capacity better reflects the effort required of AEMO for things like accreditation. • Ms Guzeleva noted that Capacity Credit allocation, certification and compliance are only part of what AEMO does in terms of Market Generators – there is also daily dispatch, system reliability and security in real time, and Generator Performance Standard (**GPS**). Ms Guzeleva advised that AEMO has confirmed that, Market Generators currently cause the majority of AEMO's efforts, not Market Customers. • Mr Schubert noted that the sent out capacity of intermittent generators causes a lot of AEMO's effort because their output can vary, so sent out capacity is a good indicator of AEMO's effort to manage the variability of intermittence. Ms White asked how storage is to be treated, would it be levied twice, once under selling and once under buying. • Ms Guzeleva noted that there will be no distinction between Market Generators and Market Customers in the future, so to allocate Market Fees, a definition would need to be determined for Market Participants that predominantly withdraw and that predominantly inject. Ms Guzeleva noted that the treatment of storage is a good question because storage will withdraw and inject in almost equal measure. • Ms White agreed with Ms Guzeleva in terms of a hybrid Facility, that they are predominantly a generator and easier to deal with even if they withdraw from the network, whereas the case of a standalone battery was more difficult and she wanted to confirm how it would be treated. • Mr Draper suggested that, to avoid double counting, a battery could be counted as a Market Participant selling energy. • Ms White asked if it would be practical for AEMO to implement this in terms of how they sort the data and given the systems that they have.	

Item	Subject	Action
	• Ms Guzeleva noted that the main question is how to properly define a 'Market Participant selling' versus a 'Market Participant buying', which could be on the basis of whether they predominantly inject or withdraw over a period of time. Ms White asked if there is a way to charge intermittent rooftop distributed energy resource (**DER**) for their contribution to AEMO workload. • Ms Guzeleva noted that allocation of Market Fees to withdrawals is proposed to be based on IRCR because rooftop PVs would not generally inject into the network when the IRCRs are measured, so the PV output would not offset consumption at this time, and these consumers will get their full cost allocation. • Mr Draper added that IRCR for a residential customer with a rooftop PV is probably the same with or without the rooftop PV, so using IRCR would not allow customers with PV to avoid paying Market Fees. • Ms White suggested that consideration needs to be given to the workload created for AEMO to manage low load in the middle of the day from DER and whether that is actually captured. Mr Kurz agreed with Ms White and sought to understand how the majority of AEMO's work is spent dealing with generators. • Ms Guzeleva noted that AEMO has indicated that the majority of its effort is focused on generators, not loads. Ms Guzeleva asked CARWG members to provide any evidence about who are the causers of AEMO market services and who are the beneficiaries of these services. Ms Guzeleva suggested that an allocation different from 50/50 could be considered if evidence suggests that there is a different split of AEMO's effort. Mr Draper presented MJA's analysis of the impact of the four allocation methods on Market Participants (slides 7-11). Mr Draper noted that allocating Market fees is not about market efficiency, it is more about fair and equitable cost recovery that reflects the effort AEMO puts into servicing different types of customers. The recommendation is to use the WEM Hybrid Method because: • it better reflects the causer-pays methodology; • it provides signals to retailers to pass costs to their customers based on IRCR; and • it is more equitable in terms of cost reflective prices that are passed through the value chain and captures new technology that will enter the market, such as storage.	

Item	Subject	Action
	Mr Carlberg indicated that he understood the benefit of the proposed changes on the market customer side, but the benefits were not as clear on generator side. Mr Carlberg noted that he sees merit in the WEM Hybrid Method, but it may add costs and complexity for both market participants and AEMO, so he leans toward allocating costs on the basis of the current method. Mr Eliot asked CARWG members to provide any advice on what their costs would be to implement the WEM Hybrid Method. Mr Draper noted that the proportion proposed for the WEM Hybrid Method could change over time. Mr Draper asked Ms Gilchrist whether AEMO saw any major concerns with the WEM Hybrid Method, such as data availability or cost. o Ms Gilchrist replied that AEMO did not have any significant concerns, as long as it has the inputs, but noted that the devil is in the detail. Ms Guzeleva noted that the simplest and lowest cost option is to make no changes to how Market Fees are currently allocated because everybody can pass Market Fees to their customers through their contracts/PPAs. Ms Guzeleva noted that objective is to achieve an equitable and fair construct for allocating Market Fees. Mr Kurz noted that the whole reason to generate is to meet load, so the causer-pays and beneficiary-pays principles suggest the Customer Only Method, but the WEM Hybrid Method is the next best option because it reflects the changing nature of the system. • Ms Guzeleva questioned the view of some CARWG members that all benefits go to consumers and that generators are not beneficiaries given that they are in the market to make profits. Mr Draper noted that uncontracted peakers, such as Tesla and Merredin, would not be able to pass on costs to customers. Ms Guzeleva acknowledged that these facilities are not charged under the current arrangements and should be consulted on how any changes would affect them. Mr Schubert noted that Market Fees are a fairly small component of total charges and that the WEM Hybrid Method seems to be the best option. Mr Arias sought to clarify whether Market Fees would be included in reserve capacity pricing moving forward. Mr Draper indicated that this could be considered.	

Item	Subject	Action
	Mr Arias indicated that he does not support the WEM Hybrid Method. Ms White suggested that it would be useful to understand what drives AEMO costs, by category, and what it would cost for AEMO to implement the WEM Hybrid Method. Ms Guzeleva questioned the effort to get a breakdown of the historic causes of AEMO's costs because these are likely to shift over time. Ms Guzeleva questioned the need to change the method to allocate Market Fees if specific benefits from the changes cannot be quantified. Mr Carlberg and Ms White agreed.	
	Action: CARWG Members are to provide evidence about who are the causers and beneficiaries of AEMO market services.	**CARWG Members (14/10/2022)**
	Action: AEMO is to consider what information can be provided to assist the CARWG in understanding the current breakdown of its expenses by market segment.	**CARWG Members (14/10/2022)**
	Action: CARWG Members are to provide estimates of the costs for Market Participants to implement the WEM Hybrid Method, including any contracting costs.	**CARWG Members (14/10/2022)**
	Action: AEMO is to provide a broad estimate of its costs to implement the WEM Hybrid Method.	**AEMO (14/10/2022)**
	5(b) Allocation of Frequency Regulation Costs Mr Draper noted that the MAC supported assessment of current NEM Causer-Pays Method and the Tolerance Method. Mr Draper presented MJA's analysis of the impact of these methods in the WEM (slides 15-17) and showed how these methods would provide incentives for participants to forecast more accurately and reduce their variability (e.g. for intermittent generators to install batteries) and that there was some efficiency benefits associated with the two approaches. Mr Draper noted the NEM Causer-Pays Method is highly complex, so there may be significant costs to implement this in the WEM. However, the AEMC has approved a rule change to simplify the NEM Causer-Pays Method and AEMO gave a presentation to MJA and EPWA on how this rule change will be implemented in the NEM. Mr Draper noted that: • under the New NEM Causer-Pays Method, payments will be provided to participants that make a positive contribution to frequency control; and • the new method is more straightforward than the current method.	

Item	Subject	Action

	Mr Draper indicated that MJA is modelling the impact of applying the New NEM Causer-Pays Method in the WEM to determine what incentives it provides, who the beneficiaries are and who is likely to be liable for the charges; and will provide that information to CARWG.
	
	Mr Draper noted the recommendation was to adopt the New NEM Causer-Pays Method to allocate frequency regulation costs, subject to results of the MJA analysis.
	
	• Ms Gilchrist advised that AEMO is in the final stages of determining how to implement the New NEM Causer-Pays Method in the NEM and noted that the exact same method did not need to be implemented in the WEM.
	
	• Ms White asked what the driver was for the new method, noting that she understood that it is simpler, but that this comes as a trade-off against the incentives to change behaviour or to accurately levy costs on those causing the need for regulation.
	  o Ms Gilchrist replied that there is a lot of information about this on AEMO's website and that the method would improve the responsiveness for Market Participants.
	  o Mr Draper noted that the new method will apply at a-Facility level, which is consistent with where we are going in the WEM.
	
	• Ms White agreed that a simpler method is better, as long as it achieves the objectives, but that she does not yet have enough information to support the New Causer-Pays Method. Mr Carlberg agreed that it seems like a good approach but that he needs more information.
	  o Mr Draper indicated that MJA would arrange for an overview of the New Causers-Pays Method as well as provide results of its analysis of the impact of the method in the WEM.
	
	• Following a question from Ms White, Ms Guzeleva clarified that the Current WEM Method, the NEM Causer-Pays Method, and the New NEM Causer-Pays Method all calculate allocations on a Facility basis and that there is no proposal to change this.
	
	• Mr Schubert noted that a good feature of the New NEM Causer-Pays Method is that it rewards those who help avoid the need for frequency regulation.	

Item	Subject	Action

- Mr Carlberg asked for an example on how a generator would help avoid the frequency regulation costs and get paid under this new method.
  - Mr McKenzie indicated that the approach considers deviations above and below the frequency target – if you generate more than your target, then you are contributing to a higher frequency, and you would get a payment if you do this when frequency is low.
  - Mr Schubert noted that batteries or generators that have a lower droop setting will respond more quickly to frequency deviations and could automatically help flatten frequency deviations, and this proposal will provide a good incentive for this to happen.
- Ms Guzeleva asked CARWG members to propose alternatives if they find the proposed New NEM Causer-Pays Method to be unacceptable. One of the recommendations in AEMO's State of the System report was that a stronger signal is needed to incentivize behaviour that minimizes the cost of frequency regulation.
- Mr Parrotte noted that he expects more storage on the system in the future and that storage may be paired with renewable generators, so where a renewable generator decreases or increases frequency and the remote battery does the reverse, there is no net impact on the system, but the current method would sting them both.
  - Mr Draper noted that this is because the two Facilities are not treated as a single Facility.
  - Ms Guzeleva noted that scheduled Facilities are expected to operate within tolerance limits and it would be unacceptable for a storage Facility to unilaterally correct frequency deviations of an associated Facility – it would be a fundamental change to the concept of the WEM to allow Market Participants to self-manage frequency deviations within a portfolio. Mr Parrotte agreed, and indicated that this is not an issue to be addressed now, but may need to be considered later.
- Ms White asked if there was a risk that many generators respond and overshoot, causing more problems.
  - Mr Schubert replied yes, and that this has to be managed by appropriate control settings.

Item	Subject	Action
	o Mr Parrotte noted that this is a risk, but if a generator does overshoot, then it would be penalised because it is no longer helping, which will encourage the right level of response. o Ms Guzeleva indicated that there should be a reward for setting market-friendly control settings, but a line needs to be drawn so that facilities do not deviate too far from their schedule, or they may find themselves in front of the regulator. o Mr Draper noted this may be self-correcting because a generator will be penalised if it does this too often and overshoots. • Ms White indicated that she understands the concept of generators responding without being dispatched for regulation, but wanted to understand how AEMO then knows that a generator did this and then quantifies the payment. Ms White asked for this to be covered when the further information is provided. Ms Guzeleva agreed with this concern. • Mr Schubert expressed the view that, as generation variability increases, there will be a need for more responses from generation, not just relying on a few generators and Automatic Generation Control (**AGC**) to manage frequency. • Ms Guzeleva and Mr Draper asked if the CARWG agreed to recommend consulting on adopting the proposed New NEM Causer-Pays Method, which is simpler and potentially more transparent, subject to the analysis being conducted on the efficiency benefits and impact of the method on Market Participants. Mr Schubert, Mr Froud and Mr Kurz supported the recommendation.	
	Action: EPWA and AEMO to arrange for further information to be provided to the CARWG on the New NEM Causer-Pays Method to allocate Frequency Regulation costs.	**EPWA and AEMO (25/10/2022)**
	Action: EPWA and MJA to provide the CARWG with the results of the analysis of the impact of implementing the New Causer-Pays Method to allocate Frequency Regulations costs in the WEM.	**EPWA and MJA (25/102022)**
	5(c) Allocation of Contingency Reserve Raise Costs Mr Draper noted that concerns have been raised that the runway method could attribute too much Contingency Reserve Raise costs to a Facility with multiple generators and multiple connection points because it is unlikely that the	

Item	Subject	Action
	whole Facility would be down at one time, rather it was more likely for an individual unit or connection to be down. Mr Draper noted Collgar Wind Farm as an example – Collgar is not registered as an Aggregated Facility but it has two connections – and suggested that it may be more appropriate for each of Collgar's units to pay for Contingency Reserve Raise, not the aggregate of the Facility. Mr Draper indicated that further analysis would be done to understand these examples so that application of the runway method does not over-recover costs for an extremely unlikely event, such as a whole power station tripping. • Ms White asked if the definition of 'generating unit/system' is appropriate. • Ms Guzeleva noted that it is not consistent with the causer-pays principle to apply the runway method to the whole Facility if the facility is only partially affected if one of the connections fails. • Ms Guzeleva noted that the issue is what is the risk to the system of a facility has more than one connection and how the site is configured. The current rules treat such a Facility as one unit under the runway method. • Mr Schubert and Mr Draper suggested that the question is what is the Credible Contingency – the whole Facility or a particular unit. Ms Guzeleva noted that this depends on how that Facility is connected to the system. • Mr Parrotte noted that Contingency Reserve Raise is there to address the loss of generation output and agreed with what was being discussed, but that there will be challenges in writing the WEM Rules to address the practical reality. Mr Parrotte noted that the intent is to set charges for the amount of generation that may be lost for a single contingency, which has nothing to do with dispatchability. • Ms Guzeleva noted that the WEM Rules will need to be changed to make sure that the risk is properly measured by AEMO and not assume that each Facility has a single mode of failure. • Mr Eliot asked whether the issue applies to Facilities that are not 'Aggregated Facilities' under the definition in the rules , noting that Collgar is not registered as an Aggregated Facility but can be operated as two separate plants. Mr Eliot noted that he did not believe	

Item	Subject	Action
	resolving this could be tied to the definition of Aggregated Facilities. o Ms White noted that the issue is about Facility configuration and that Collgar is structured such that it can operate as two totally separate wind farms. Providing an incentive for Facilities to configure in this way will mitigate the need for Contingency Reserve Raise. o Mr Eliot agreed that this would provide the right signal but noted that this may make rule drafting challenging. • Ms Guzeleva noted that, based on the causer-pays principle, we should not penalise Facilities just because they happen to be on the same site or are aggregated by AEMO, if their mode of failure does not mean that the whole Facility is out, as their connections can operate independently. • Mr Draper asked Ms White whether Collgar had one or two connection points. Ms White confirmed that Collgar has two connection points. o Mr Draper noted that, in that case, Collgar would not have an aspect of a connection failure either, but would be hit for the whole Facility under the runway method rules that are coming into force on 1 October 2023. • Mr Parrotte noted that the runway method should ideally be based on the generation output that would be lost for a single contingency. Whether that can be done in the rules effectively/efficiently is what needs to be determined.	
	5(d) Contingency Reserve Lower Costs Mr Draper noted that: • large battery electricity storage systems (**BESS**) may enter the market soon – batteries up to 250 MW are being considered – which would more than double the largest credible load rejection contingency; • large batteries would only get a minor share of Contingency Reserve Lower costs under the current allocation methodology; and • MJA is developing a runway method to address this issue, and provided an example (slide 26).	

Mr Draper asked if the CARWG supported exploring allocating Contingency Reserve Lower costs using a runway approach, noting that:

- allocation could not go down to the smallest load because of the lack of interval metering, so it would likely only apply for Facilities 120 MW and up; and
- there will be challenges to managing issues around the thresholds for any tranches used in the runway method.

Mr Draper asked for feedback from the CARWG.

- Mr Carlberg noted that a runway method seems to make sense but asked whether big Non-Dispatchable Loads present the same risk of requiring load rejection service as smaller Loads.
- Ms Guzeleva noted that:
  - o it is very unlikely that several Non-Dispatchable Loads will be simultaneously impacted by the same issue, it is more likely to be a network issue, in which case the Contingency Reserve Lower costs should be allocated to the network provider rather than the individual Loads; and
  - o it is not consistent with the causer-pays principle to send a cost signal to the smaller Loads that have suffered an outage because of a network component.
- Mr Draper suggested using the existing allocation method for Loads up to 120 MW focusing the runway method on larger Loads.
- Ms White noted that the runway method for Contingency Reserve Raise includes networks, so it would be consistent to do the same for Contingency Reserve Lower.
  - o Ms Guzeleva noted that networks are allocated Rate of Change of Frequency (**RoCoF**) services costs, not Contingency Reserve Raise.
  - o Ms White agreed that the runway method for Contingency Reserve Raise allocates costs for network contingencies to the generators on that part of the network, but noted that it could be argued that networks should pay these costs.
- Ms White noted that the runway method was not previously implemented for Contingency Reserve Lower because of the complexity and cost associated with it, but she can see merit in the method if the tranche approach can achieve some of the benefits of the method without the complexity.

Item	Subject	Action
	• Ms Guzeleva noted that it would be important to make sure that the cutoff is appropriately placed (e.g. the 120 MW) and that interval metering would be required for this to properly work. • Ms White asked whether small Loads are essentially netted off in the Notional Wholesale Meter, and noted that she believed there was previous consideration of Loads behind TNIs or substations but there was not appropriate metering. Ms Guzeleva asked if the CARWG supported exploring the application of the runway method. • Mr Parrotte noted that: o networks are subject to the technical rules, so it would be rare that they cause big contingencies; o the intent appears to be to pick a level below which you do not need to worry any more, and 120 MW seems reasonable; o bigger Loads and BESS will be operating in the future and should have SCADA; and o Woodside is conscious of this and is trying to design its plant not just from a reliability perspective, but also in consideration of the impact that it can have on the power system. Mr Parrotte noted a line had to be drawn somewhere and agreed with Mr Eliot, that bands above that line could drive perverse behaviour, and suggested that a reasonable compromise may be to require any Load or BESS above 120 MW to have SCADA – then you can do a full runway approach above that point.	
7	**Next Steps** A summary of the outcomes of this CARWG meeting will be provided at the MAC meeting on 11 October 2022, which will feed into the Consultation Paper to be published in December 2022. MJA's literature review will be published along with the Consultation Paper.	
8	**General Business** No general business was discussed. The next CARWG meeting is scheduled for 22 November 2022 (pending a meeting for AEMO and MJA to present to the CARWG on the New NEM Causer Pays Method for Frequency Regulation costs).	

The meeting closed at 3:00pm.

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

Minutes

Meeting Title:	Cost Allocation Review Working Group (**CARWG**)
Date:	25 October 2022
Time:	1:00pm – 3:00pm
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Sam Lei	Alinta Energy	Proxy for Oscar Carlberg
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
Genevieve Teo	Synergy	
Paul Arias	Shell Energy	
Mena Gilchrist	AEMO	
Tom Frood	Bright Energy	
Cameron Parrotte	Woodside	
Grant Draper	Marsden Jacob Associates (**MJA**)	Presenter
Peter McKenzie	MJA	Presenter
Hugh Ridgway	AEMO	Presenter
David Scott	AEMO	Presenter
Lisa Laurie	AEMO	Observer
Stephen Eliot	Energy Policy WA (**EPWA**)	
Shelley Worthington	EPWA	

Apologies	From	Comment
Jason Froud	Synergy	
Oscar Carlberg	Alinta	

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.	
3	**Minutes of CARWG Meeting 2022_09_27** Draft minutes of the CARWG meeting held on 27 September 2022 were distributed in the meeting papers on 19 October 2022.	
4	**Action Items** The action items were taken as read.	
5	**New NEM Causer-Pays Allocation Method for Frequency Regulation** Ms Guzeleva welcomed the staff members from AEMO who were present to discuss the New National Energy Market (**NEM**) Causer-Pays Method to allocate Frequency Regulation costs.	
	5(a) Explanation of the method Mr Scott noted that the Australian Energy Market Commission (**AEMC**) had approved a change to the NEM Rules to introduce incentive arrangements to replace the existing NEM Causer-Pays Method that: • institutes payments for parties that provide good frequency response (primary or secondary response); and • allocates the cost of regulation Frequency Control Ancillary Services (**FCAS**). Mr Scott noted that AEMO is developing a procedure to implement the New NEM Causer-Pays Method, which will be a data-driven project, requiring real-time calculation and publication as soon as possible. Mr Scott provided an overview of the Existing Causer-Pays method, noting that it is a cost allocation mechanism for regulation FCAS, which is an Automatic Generation Controlled (**AGC**) enabled every 5 minutes to correct dispatch and forecast errors. Mr Scott noted that nearly all the large units in the NEM were on AGC, particularly all of the coal and gas units, that some peaking units are not on AGC and are manual or operator controlled, and that there were some aggregated units that were semi ACG. Mr Scott indicated that the Existing NEM Causer-Pays is based on four-second unit deviations from a straight-line dispatch trajectory compared to a central measurement. Mr Scott indicated that a performance indicator is calculated and tells you whether your deviation is good or bad and also how good or bad. Any positives deviations are ignored and the negative deviations are summed by Participant. The total sum of each Participants' factor over the total sum of all Participants results in a percentage, which is multiplied by the requirement cost to equal the settlement amount for each Participant.	

Item	Subject	Action
	• Ms Laurie asked whether this was based on SCADA values and if the SCADA values were replaced with any metered values later. Mr Scott answered that they do not use metered values, just one single set of data. • Mr Lei asked, when measuring good and bad performance, whether that was based on luck and what the grid is doing rather than something that the facility can control. Mr Scott provided examples of how performance could be measured and Mr Ridgway added that the current method is based on AGC and it may be difficult for participants to work out, but the new system will be based on the actual frequency itself and participants will be able to calculate for themselves what performance should be in real-time, based on local frequency. • Mr Schubert noted that there may be a number of units on AGC and asked if, in any particular interval, there may be only one or two contributing to the requirement. Mr Scott replied that this would be fairly unusual but noted there have been instances where response had concentrated in certain regions, and that the reserve services like FCAS will tend to migrate to the cheapest state where those reserves are available and they may be enabled more because they will be more competitive. Mr Scott noted that in some circumstances there was high participation by some providers who can provide a lot of FCAS because they have high ramp rates (i.e. batteries). Coal and gas-fired generators would typically have a number of units on and would tend to mimic their bids, spreading them across all of their units, in effect distributing their ramping responsibilities across all of the units. Mr Scott noted that increased provision by some large batteries with extremely high ramp rates meant they can provide regulation FCAS very well, but in doing so will probably push down prices. Mr Schubert indicated that he was trying to compare the NEM with the system in the Wholesale Energy Market (**WEM**) and that it was his understanding that there are only a few units participating in FCAS in the WEM. Mr Scott noted that, because FCAS is a co-optimized market service, there is not a lot of difference between treatment of regulation FCAS and energy. Mr Scott noted that the market in the NEM is quite a lot deeper than the WEM in terms of the provision of regulation. Mr Scott explained how the deviations would be calculated in the New NEM Causer-Pays Method noting: • it will be every four seconds; • the trajectory is subtracted from the active power measurement; and • there is a rule that all deviations will balance to allow allocations to the metered population. Mr Scott noted the performance measure indicates a positive generating unit deviation when aligned with a positive performance measure and that a negative generating unit deviation when aligned with a negative	

Item	Subject	Action
	performance measure is good. The good performance is when it is aligned with the yellow line, the dark area indicates the good deviations and the lighter area bad. The data is separated for Raise and Lower as those two markets tend to have fundamentally different cost characteristics at any one time, so it was determined to separate the cost allocation and payments associated with those. Mr Scott noted that was probably an improvement overall. Ms Guzeleva noted that it appeared there would be an incentive for generators second guess what is happening and not match the target in the dispatch instruction and asked if this is a risk or if it is considered to be self-correcting. Mr Scott noted that AEMO cannot do anything to control output, but most parties would want to operate in the regulation markets and are obligated to comply with their dispatch targets – AGC is the primary arrangement for this. The main reason for mandatory Primary Frequency Response (**PFR**) in the NEM was because generators were turning off their droop response within a certain hertz dead band, and only providing it beyond that, and AEMO were not controlling frequency within that band because the regulation system was too slow. The rule change requires all generators to provide PFR at a very tight hertz dead band, so as soon as frequency starts moving outside that band, generators will tend to respond according to the PFR requirements which specify that there must be a certain amount of droop and a certain amount of response within 10 seconds (subject to certain agreed changes by exception). This means there are a lot of units on AGC, a lot of units aiming to provide regulation FCAS by making ramping available, and nearly all of the units are providing droop response, and the intent is that this will provide a stable level of primary and secondary response. If parties start trying to second guess what the requirement is, AEMO would expect that would start to correct itself over time. • Ms Guzeleva noted that the analysis suggests that, while that is happening, bids in the FCASS will be lowered and asked why that was expected. • Mr Scott replied that this was because, for units providing regulation FCAS, the AGC system is set up so that they respond reasonably fast and provide a lot of the required response, and they are paid for that response and, because the regulation market is reasonably competitive, we expect them to take account of that in their regulation offers. • Mr Scott noted that overall the behaviours should be balancing. Mr Scott noted the current arrangement for calculating contribution factors only allows recovery of FCAS costs, and the new method tries to capture all of the response in the system, including good PFR. • Ms Guzeleva expressed concern that the existing method is quite complex but that the new method appears to be equally complex, and asked which of the two methods would be simpler to apply. Mr Scott	

Item	Subject	Action

replied that the new method is a vast improvement, and under no circumstances should the old method be applied as it was designed. Moving towards calculating more real time factors in each dispatch interval rather that over a 28-day period was an important feature of the new method.

- Ms White asked if it would be more costly to implement the existing or new method. Mr Ridgway indicated that was difficult to say because the new method has not been implemented and will not just deal with cost allocation, but will also create incentives for PFR, which is a value add for the new method.
- Ms Guzeleva asked if the main advantage was that it incentivises the right behavior.

Mr Scott indicated that the rule change is not really about incentivising PFR but about charging the parties that might cause PFR and paying the parties that are providing that PFR. Mr Scott noted the aim is also to try and improve the performance of the secondary response. Left unaddressed, plant which is inherently variable or have poor control would receive a cross subsidy because the units on PFR would be compensating for it.

- Ms White noted there are many facilities in the WEM that do not have AGC, rather they have Automatic Balancing Control (**ABC**), and asked if this would cause an implementation issue (other than those facilities presumably not being able to adjust their behaviour to minimise regulation demand).
- Mr Scott noted those units will probably be on PFR response and could provide primary droop response and can control their output, so they could be paid through this or be indifferent to it.
- Mr Lei asked if it was correct to assume facilities which have a tighter droop dead band would have a better performance factor and hence be paid for their performance.
    - Mr Ridgway responded that you would expect a tighter dead band to improve your performance, but noted there are other factors at play here. For example, how you determine the frequency measure and how accurately you follow that measure.
    - Mr Ridgway noted that another thing to remember is that your factors are not just determined by whether you are providing frequency response, but also how much stress the system is under and a performance metric will calculate your contribution factors. Mr Ridgway added that incentives are more heavily weighted towards periods where frequency may be more strongly deviated from the ideal, where you might have a wider dead band and, by doing more when the system is really under pressure, you would expect to get a much better contribution factor than someone who is just doing a little bit all the time.
    - Mr Scott added that the droop settings and the speed of response would also be important.

Item	Subject	Action
	- Mr Schubert noted that most generators in the NEM seem to be controlled on AGC and asked if that is for their normal scheduled MW output, noting that it was his understanding that AGC is only used in the SWIS for frequency control units. - Mr Parrotte noted that it was probably a bit of a mix and it was his understanding that everyone will go onto AGC in the new market. - Mr Schubert clarified that he was thinking more about real time dispatch and if there is a difference between the WEM and in the NEM, and if this was through AGC settings or through other signals. - Mr Scott indicated that he could not speak for the WEM but that the NEM is not dependent on all units being on AGC. If units in the NEM are not on AGC and are manually controlled, and they are not very good at following their targets, then this will cost them, which is a good thing. - Mr Schubert agreed, noting he was trying to understand where our methods in the WEM might not be as good. - Ms White noted some facilities have a substantial SCADA lag and asked if this would cause equity issues in implementing this method (lag in signals to adjust behaviour compared to other facilities with little SCADA lag). - Mr Ridgeway noted they were looking at this in the implementation of this project and one partial solution is looking at using local frequency readings to determine a bespoke frequency measure for the unit. Mr Ridgeway noted that AEMO did not know if it will go down that path because it is still subject to consultation and adding a new SCADA channel is not trivial. AEMO will also consider setting an appropriate frequency measure, not just using a raw frequency deviation, that will be a moving average component over, say, 120 seconds so that it is slower and really only substantial frequency deviations that lead to strong factors will be generated. - Ms White noted that Collgar has about a 30 second SCADA lag, which is substantial, so even if it spends the money to get AGC, there is a risk that it will contribute to costs if it responds to an old signal. - Mr Scott suggested that the impact on financial settlements might not be large because everyone has a bit of a delay, but that was something to be proven through trials. Mr Scott noted that there is a requirement in the NEM for corrective response, so the size of the frequency deviation does not dictate the cost. A relatively small frequency deviation could cause a large error on the system, which may be hidden because there was lots of droop response available, so ideally you would identify that they are all good performers and would pick this up in the calculation of the requirement for corrective response.	

Item	Subject	Action

Mr Schubert noted that encouraging good droop response seems to be a key ideal and asked whether most WEM generators are on 4% droop.

- Ms Guzeleva noted that generator performance standards (**GPS**) will apply in the WEM and that people were working with Western Power to negotiate their compliance. The GPS require certain droop response and that a key objective of the GPS is to incentivise the right behaviour so that customers do not need to buy more regulation through the market.

Ms Guzeleva noted the New NEM Cost-Reflective Method sounds better than the old method in that it will provide better response and asked if it will appropriately target financial incentives at those that can respond to that incentive to behave in a better way.

- Mr Ridgway suggested that it is appropriate for a facility that cannot respond to still wear costs because, if you are looking to invest and build a new facility, then you should be mindful that this is a real cost that this type of facility is going to impose on the system, or vice versa for a facility that responds well to this incentive.
- Ms Guzeleva noted that the New NEM Cost-Reflective Method appears to try to incentivise a positive behaviour from those that can provide it, but does not do much to change intermittent generators' behaviour through the cost allocation mechanism.
- Mr Scott suggested that it will change behaviour because the current arrangements only recover FCAS costs, and the new mechanism will also provide incentives for new investments, which is the other important aspect of this.

Mr Draper noted, with regard to the ability for renewables to provide regulation services, that a wind farm can back off a bit if the spot price is negative because of solar output and then provide regulation raise services when coal may not be operating. If batteries are charging, then wind will be the marginal plant and will need to provide this service, and should be compensated. Mr Draper noted the solar and the duck curve effect fundamentally changes the system and plant can benefit from these payment streams because of the changing nature of how and who is going to be providing these services going forward.

Mr Scott noted the separation between Raise and Lower are not in the current arrangements, and this is important because it provides opportunity to maximize performance against the prevailing dispatch conditions.

Ms Guzeleva queried how the New NEM Causer-Pays Method would sit with GPS, and whether it would mean starting to pay for something that is a compulsory provision under GPS.

- Mr Scott noted that there is not a full mandate to provide PFR in the NEM, it is a mandate to operate with your governor setting in a particular way. Mr Scott noted that it was not really about making a payment to those that are mandated, but about redressing the fact that parties that are currently providing PFR are forced to provide this

Item	Subject	Action
	response while others can be operating in a very random way, maximizing their output but causing all sorts of dispatch errors, and those PFR units have to compensate for this. Ms Guzeleva noted that in the WEM there are dispatch tolerances and that we currently have PFR that is not paid for because it is part of the minimum standard on the system, but people take this into account and would incur penalties if they go outside dispatch tolerance limits. Mr Scott noted that there was nothing like tolerance limits in the NEM, rather a requirement to comply with dispatch instructions and asked what the value was of a tolerance limit. • Ms Guzeleva replied that a Participant who repeatedly steps outside these would face the regulator. • Mr Scott noted that was more of a regulatory solution rather than pricing the deviations at any one time. Ms Guzeleva noted that it would have been preferable for the New NEM Causer-Pays Method to have already been implemented so that we can find out what behaviour it incentivises, and queried the practicalities of implementation, noting that AEMO would implement this by 2025 while the WEM was moving to a new market in 2023. Mr Ridgway added that the system is designed to be very flexible, and the frequency measure can be changed if it is not accurately describing which direction you want people to move in. Mr Scott agreed with Ms Guzeleva and noted that the NEM has a regulated requirement to provide mandatory PFR and found that PFR is not really suitable for the new FCAS market. Therefore, it was determined that it is best to use secondary response bidding arrangements to create a market and that the Causer-Pays arrangements can be extended to compensate for both primary and secondary response. Mr Scott noted there was no intent to replace the mandatory requirement, rather the design was intended to work with that requirement while the AMEC was very keen to remove the requirement. Ms Guzeleva asked if unmetered generation pick up a proportion of the charges and Mr Scott replied that they did. Ms Guzeleva thanked Mr Scott and Mr Ridgway for their presentation.	
	5(b) Modelling Results – Application of the Method in WA Mr McKenzie indicated that MJA modelled the New NEM Causer-Pays Method based on four-second SCADA data, recreating a sample WEM day for a small sample of plant covering most of the plant types, focussing on the Causer-Pays factors and how these were assigned. Mr McKenzie indicated that there was a slight difference between the actual and modelled generation depending on what plant was generating at the time. • Mr Lei asked how the performance of wind farms was calculated as they do not receive dispatch target. o Mr McKenzie noted dispatch targets were made up for the WEM and provided slide 5 as an example, where for Meriden Solar	

Item	Subject	Action
	they looked at the generation during the time period and took an average value. • Ms Guzeleva asked, in the absence of dispatch targets in the WEM dispatch process, did they intend to use forecasts. o Mr Ridgway noted they used forecasts in the NEM. o Mr McKenzie replied yes that they would be using forecasts and Mr Draper noted that, in that instance, they were likely under forecasting the liability for solar and wind. • Ms Guzeleva noted that, if this method were to be implemented in the WEM, it would have to use forecast quantities and asked if there is a way to model this to use realistic forecasts to see what the deviation would be, noting that it would be important to get an understanding of the real impact. • Mr Draper noted that they could develop a forecasting methodology to determine the scale of the liability for intermittent plants, noting that MJA used the average in its modelling due to time constraints. • Mr McKenzie noted, for the Causer-Pays factor per MW of capacity (after scaling), that the amount of deviation per MW of capacity was similar for solar and wind, which had higher contribution factors. Mr Draper noted that, because no one was below the line, they were all liable but that wind and solar were the greatest payers per MW for the sample day, and then coal and gas plant. Mr McKenzie noted that, based on the small sample set, the New NEM Causer-Pays Method assigned more costs to demand compared to other methods and that slide 15 showed a breakdown of the percentages by generator type, with wind the biggest contributor for the sample day. Mr Draper noted demand was getting more than 50% of the contribution factors. Mr McKenzie noted that the assumptions made with the mean contribution factor resulted in more skewing towards demand than other methods and that this could change as the method is finalized. The process was repeated for five days and Mr McKenzie noted that there was some variation between days. Mr Draper noted that the greatest variation was for solar, with demand varying substantially as well. Mr McKenzie agreed that solar had the biggest variation, with coal and gas fairly steady, and noted that Open Cycle Gas Turbines (**OCGT**) could change depending on how much is dispatched on an individual day. Ms White asked how the payments for these facilities would change under the new NEM Causer-Pays Method compared to the Current NEM Causer Pays Method and the current WEM method. • Mr Draper replied that MJA's comparison across the different methodologies was depicted on slide 17 and Mr McKenzie added that the results were aligned across the methods.	

Item	Subject	Action
	• Mr Lei noted that the new NEM method shifts the costs to generators from loads currently paying 90% to generators paying ~50% and asked whether this was proportional to the issue they are causing. • Mr Draper noted that loads are getting more costs because there is not much solar plant on the system, and wind and solar will probably end up being about 50/50 by 2030 as more wind and solar plant enters the system. • Mr Draper indicated that he believed that there will be similar percentages by about 2030. • Ms Guzeleva asked, if that was the case, then the key question is – are we actually reducing the overall costs. • Mr Draper suggested that they needed to determine whether causer-pays pricing results in reduced deviations and reduced regulation requirements (both up and down) leading to a lower overall cost for the system. • Ms Guzeleva agreed, noting that the cost of implementing a new but more complex method in the WEM had to lead to an overall system benefit that far outweighs that cost. Mr Draper noted that the WEM requirement for regulation will increase from 110 MW at peak to around 300 MW with the amount of renewables and solar coming onto the system over the next decade. Ms Guzeleva noted that the costs to move to the New NEM Causer-Pays Method and the impacts of that method on growth in services between now and 2030 needs to be better understood, and that we would be in a better position to understand the overall cost and impact on the system if the NEM had implemented it five years ago. Mr Draper noted that as part of this exercise, they would have to attempt to determine what the tangible benefits will be in implementing Causer-Pays and that MJA would look at the NEM to try to work out what that would look like without the Causer-Pays methodology and how it would have been different. • Ms White asked if the NEM method planned to also include the residential loads. • Mr Ridgway replied that everyone who participates in the market will be impacted by this, as it is aggregated together and treated as a pool. If you are a residential load without four-second metering, then you fall into the residual and you receive a portion of the cost along with everyone else who is not metered. Mr Scott added that was the residual deviation. • Ms White asked if that was captured in the light blue slot on slide 17. • Mr Draper replied that demand was captured on slide 15 and that includes all the notional meter customers. On slide 17 demand was removed to focus on generation. • Ms White asked whether the notional meter still had the netting off affect or is it able to do the sum of the residual for each load.	

Item	Subject	Action
	• Mr Draper noted that they were just doing an aggregate demand trace, not individual values and Mr McKenzie added that it was just one residual value. • Ms Guzeleva clarified that this was not splitting photovoltaic supply from demand that it looks at the notional meter as a whole. • Mr Schubert noted that the costs and benefits need to be worked out, but that if incentivised, fast acting wind and solar with inverters could help with frequency regulation and, in the future, that would be a cheap source of regulation capacity if they were incentivised to help by operating below their potential output. • Ms Guzeleva noted that in the new market they will be able to provide regulation and that it was a question of how to provide that incentive, by either: o encourage them strongly via pricing or otherwise to participate in the actual market for services; or o reward them for something that they would do naturally.	
7	**Next Steps** Next steps were not discussed due to time constrains.	
8	**General Business** No general business was discussed. The next CARWG meeting is scheduled for 22 November 2022	

The meeting closed at 3:00pm.

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

Cost Allocation Review

Consultation Paper

15 December 2022

Working together for a brighter energy future.

An appropriate citation for this paper is: Cost Allocation Review

Energy Policy WA
Level 1, 66 St Georges Terrace
Perth WA 6000

Locked Bag 100, East Perth WA 6892
Telephone: 08 6551 4600

www.energy.wa.gov.au
ABN 84 730 831 715

Enquiries about this report should be directed to:

Email: EPWA-info@dmirs.wa.gov.au

Contents

Tables

Figures

Glossary

Term	Definition
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AGC	automatic governor control
BESS	battery energy storage systems
BSUoS	balancing service use of system
BTM	behind-the-meter
CAISO	California Independent System Operator
CARWG	Cost Allocation Review Working Group
Coordinator	Coordinator of Energy
DER	distributed energy resources
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ERCOT	Electricity Reliability Council of Texas
ESS	Essential System Services
FCAS	Frequency Control Ancillary Services
FCESS	Frequency Control Essential System Services
GW	gigawatt
GWh	gigawatt hour
IRCR	Individual Reserve Capacity Requirement
I-SEM	Integrated Single Electricity Market
kW	kilowatt
kWh	kilowatt hour
LRR	Load Rejection Reserve
MAC	Market Advisory Committee
MW	megawatt
MWh	megawatt hour
NCESS	Non-Co-optimised Essential System Services

Term	Definition
NEM	National Electricity Market
NMI	national meter identifier
PJM	Pennsylvania, New Jersey, and Maryland Interconnection
PV	photovoltaic
RoCoF	Rate of Change of Frequency
RCM	Reserve Capacity Mechanism
SCADA	supervisory control and data acquisition
SRAS	System Reserve Ancillary Service
STEM	Short Term Energy Market
SWIS	South West Interconnected System
TNSP	transmission network service provider
VRE	variable renewable energy
WEM	Wholesale Electricity Market

Unless otherwise defined, capitalised terms have the meaning prescribed in the WEM Rules.

Executive Summary

Cost Allocation Review

Clause 2.2D.1(h) of the WEM Rules confers the function on the 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.

The Coordinator, in consultation with the MAC, is reviewing the allocation of Market Fees and Essential System Services (**ESS**) costs under clause 2.2D.1 of the WEM Rules. The Cost Allocation Review has reached some preliminary conclusions and developed proposals for changes to the relevant cost allocation methods.

Call for Submissions

Stakeholder feedback is invited on the preliminary conclusions and the proposed changes, where relevant, to the cost allocation methods presented 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 5:00 pm WST on Thursday 9 February 2023. Late submissions may not be considered.

Approach to the Review and this Consultation Paper

The purpose of the Cost Allocation Review is to develop proposals to align the allocation of Market Fees and ESS costs with the causer-pays principle, to the extent practicable and efficient.

The guiding principles for the Cost Allocation Review are that the fee and cost allocation methodologies should:

1. meet the Wholesale Market Objectives;
2. be cost-effective, simple, flexible, sustainable, practical, and fair;
3. provide effective incentives to Market Participants to operate efficiently to minimise the overall cost to consumers; and
4. use the causer-pays principle, where practicable and efficient.

This consultation paper presents:

- a qualitative assessment of whether the current cost allocation methods are aligned with the guiding principles and, where there is not good alignment, proposed options for methods that are more consistent with the guiding principles; and
- a quantitative assessment of the impact of the proposed options on Market Participants, in comparison to the status quo.

Market Fees

Market Fees are levied to recover costs for a range of market services, as follows:

1. Market Fees to recover costs for AEMO's market operations, system planning and market administration services;
2. System Operation Fees to recover AEMO's costs for its system operation services;

3. Regulator Fees to recover the ERA's costs for its monitoring, compliance, enforcement, and regulation services; and
4. Coordinator Fees to recover the Coordinator's costs for its functions under the WEM Rules, including the costs and expenses for the Chair of the MAC.

Currently, each Market Participant is charged a Market Fee based on their sent out generation and/or load for all of their Registered Facilities and Non-Dispatchable Loads, for all Trading Intervals in a billing period.

The qualitative assessment of the Market Fee allocation method made the following observations:

1. Who should be charged Market Fees to recover the costs of market services:
   - Both Market Generators and Market Customers can be regarded as a "causer" and "beneficiary" of market services, which provides justification for levying charges on both Market Generators and Market Customers.
   - Guidance on who should bear these costs can be obtained by considering the purpose of levying Market Fees:
     - If the primary purpose is market efficiency, then this is about sending a signal for participants to optimise their use of the relevant market services. However, Market Fees contribute only about 0.5% of the total cost of electricity, so changing the Market Fee allocation method is unlikely to incentivise Market Participants to change their use of market services.
     - If the primary purpose is cost recovery, then the focus should be on ensuring efficient recovery of the relevant costs. It may be less efficient to charge Market Fees to generators (and network operators) because these fees will need to be passed through to retailers under their wholesale supply agreements (or included in network access agreements if levied on network operators). However, as cost allocation arrangements are already in place, any efficiency gains are likely to be offset by the cost of implementing alternative arrangements.
2. Is the current use of Grid MWh[1] as the basis for charging Market Fees equitable:
   - Levying Market Fees on metered generation or loads (Grid MWh) means that the level of cost recovery is proportional to energy generated or consumed, which may result in inequities because:
     - a Market Customer whose portfolio has significant installed behind-the-meter (**BTM**) PV will pay relatively less Market Fees than one with little BTM PV, but the cost of providing market services to Market Customers will likely be the same irrespective of the level of BTM PV in their portfolio; and
     - a Market Generator whose portfolio has a low capacity factor will pay relatively less Market Fees than one with high capacity factor, but the cost of providing market services to Market Generators will likely be the same irrespective of capacity factor.
3. Assessment Against the guiding principles
   - While the current method to allocate the costs for market services is consistent with the principles of cost effectiveness, simplicity and practicality, it is likely to result in some

[1] Grid MWh refers to sent out generation or electricity delivered to loads via a transmission system (not electricity generated and consumed behind the meter).

inequities. The currently method may favour Market Customers with particular types of end customers and particular generators over others, as indicated above.

A range of options were considered to overcome some of these potential shortcomings of the current Market Fee allocation method – see Section 3.2.

While it was demonstrated that some of the identified options may lead to a more equitable allocation of costs between Market Participants, changing the allocation method is unlikely to change the Market Participants use of the relevant services and there are likely material costs associated with implementing these options. AEMO would have to develop new systems and procedures to implement these options, and Market Participants would have to implement changes to their settlement and billing systems and make changes to their wholesale contracts.

Changing the Market Fee allocation method is a low priority relative to other current reform initiatives, including those required to decarbonise the South West Interconnected System (**SWIS**) and maintain system reliability. While changing the method to allocate Market Fees may provide for a more equitable allocation of market service costs, it would not increase the affordability, reliability, safety or security of supply and would provide no major identifiable benefit to Market Participants or end customers.

Conceptual Design Proposal 1:

- Retain the current method for allocating market services costs to Market Participants.
- Ignore recharge energy when allocating Market Fees to storage facilities.

Consultation Question 1:

Do stakeholders support:

(a) retaining the current method for allocating Market Fees to Market Participants; and

(b) ignoring recharge energy when allocating Market Fees to storage facilities?

Frequency Regulation

Frequency Regulation (currently Load Following Ancillary Services) is required to respond to frequency deviations that can arise due to:

- deviations between forecast and actual output from intermittent generation;
- scheduled generators and scheduled loads deviating from dispatch targets, other than in response to a frequency deviation;
- differences between aggregated customer load profiles and generator ramping profiles within a dispatch interval; and
- load forecast errors, including unexpected variations in Distributed Energy Resource output.

Frequency Regulation costs are recovered from Non-Dispatchable Loads, Semi-Scheduled Facilities (i.e., Variable Renewable Energy (**VRE**) plant) and Non-Scheduled Facilities in proportion to the absolute values of their metered generation or consumption in the relevant Trading Interval. Given the relatively low proportion of VRE plant in the SWIS compared to Non-Dispatchable loads, 90% of Frequency Regulation costs are currently recovered from loads, but this will change as VRE plant penetration increases.

The current cost recovery mechanism does not provide a price signal to loads, VRE plant or scheduled generators to minimise the requirement for Frequency Regulation, which is contrary to the causer-pays pricing principle. This means that the current cost allocation method will not incentivise Market Participants to minimise the long-term cost of electricity supply.

Four alternative methods for allocating Frequency Regulation costs were identified that may better align with the causer-pays principle, be more consistent with Wholesale Market Objectives, and provide price signals to Market Participants to minimise variations in generation/load to reduce the future requirement for the service and its associated costs (see section 5.4).

These alternative methods attempt to attribute costs to the facilities/loads that contribute to volatility, the need for Frequency Regulation services and the Frequency Regulation costs. All of these methods provide incentives for Market Participants to reduce Frequency Regulation costs by means such as better forecasting, installation of storage facilities, and providing ESS Raise services.

The preferred method, the “WEM Deviation Method” which is based on cost recovery on deviations from average generation (or load) over a 5-minute dispatch interval in the WEM This method is preferred because it:

- is simpler to implement;
- provides incentives for Market Participants to minimise deviations in generation and loads;
- does not provide incentives for ‘gaming’ by Market Participants to avoid charges; and
- is more consistent with existing WEM frameworks (i.e., Primary Frequency Response, Tolerance Ranges and Frequency Control ESS).

As outlined in Section 5.6, there are additional benefits with adopting the new NEM Causer-Pays Method and this method should be considered after it has been implemented in the NEM in 2025 and has operated for a period (e.g., an assessment in 2027 with possible implementation in the WEM in 2028/29).

Conceptual Design Proposal 2:

- Implement the WEM Deviation Method to allocate Frequency Regulation costs in 2024/25, following the implementation of the new WEM arrangements on 1 October 2023, subject to a cost/benefit assessment.
- Reassess adoption of the new NEM Causer-Pays Method to allocate Frequency Regulation costs in 2027, for potential implementation in 2028/29.

Consultation Question 2:

Do stakeholders support:

(a) adoption of the WEM Deviation Method in 2024/25 to allocate Frequency Regulation costs, subject to a cost/benefit analysis; and

(b) reassessment of the New NEM Causer-Pays Method to allocate Frequency Regulation Costs in 2027, for potential implementation in 2028/29?

Contingency Reserve Raise

The method to allocate costs for Contingency Reserve Raise services (also known as Spinning Reserve Ancillary Service) is out of scope for this review.

However, to ensure consistency with the causer-pays principle, the Facility Risk Value used in the current runway method for cost allocation should be amended to take into account lower risks from a generator configuration where the Facility has multiple dispatchable units with separate network configurations.

In such circumstances, the multiple dispatchable units should not be aggregated when applying the runway method to recovery Contingency Reserve Raise Costs, as aggregating the dispatchable units would over-estimate their Facility Risk Value and over-recover Contingency Reserve Raise costs from the relevant Market Participant.

Conceptual Design Proposal 3:

Application of the runway method should be adjusted to cater for situations where a Facility has multiple dispatchable units with separate network connections. In this situation, each separate dispatchable unit should be treated separately in the runway method (i.e., they should have separate FacilityMW for the purposes of Contingency Reserve Raises cost recovery).

Consultation Question 3:

Do stakeholders support treating separately the units in a Facility for the purpose of calculating the Facility's Contingency Reserve Raise costs, where the units are separately dispatchable and have separate network connections?

Contingency Reserve Lower

Contingency Reserve Lower is required to cover the risk of a material increase in system frequency due to a loss of single large load, or multiple loads on a single network element.

The requirement for Contingency Reserve Lower services is a function of the size of the load that may be lost, which is analogous to how the loss of the largest generator is the primary causer of Contingency Reserve Raise requirements. A modified runway method could be applied to allocate Contingency Reserve Lower costs to the largest loads operating in a trading interval – this would be consistent with the causer-pays principle and with how Contingency Reserve Raise costs are recovered.

This will be important given plans to build large battery energy storage systems (**BESS**) in the SWIS. Installing large BESS in the system could substantially increase the Contingency Reserve Lower requirements and the BESS should bear additional costs associated with the increased Contingency Reserve Lower requirements. A modified runway method to allocate Contingency Reserve Lower costs would achieve a causer-pays approach and may give BESS developers an incentive to reduce the size of the dispatchable units to reduce their liability for these costs, which could be an efficient outcome.

Contingency Reserve Lower requirements can arise from a facility or network outage. As demonstrated in Section 7.3.2, a large load or BESS locating in a less reliable part of the SWIS could increase the Contingency Reserve Lower requirement, as it imposes both a Facility (or Load) Risk and Network Risk and, under a causer-pays approach, the costs associated with the higher Contingency Reserve Lower requirement should be allocated to the large load or BESS.

Conceptual Design Proposal 4:

Apply a modified runway method to allocate Contingency Reserve Lower costs.

If a Network Contingency sets the Contingency Reserve Lower requirement in a trading interval, the costs of procuring contingency reserves are proposed to be split into two components (Load Contingency Reserve Lower and Network Contingency Reserve Lower) and costs are proposed to be allocated as follows:

(1) Load Contingency Reserve Lower cost allocation:

- apply a runway method to allocate the individual load component of Contingency Reserve Lower costs, treating all loads with capacity less than or equal to 120 MW as if they were a single 120 MW load; and
- apply the existing allocation method to allocate load Contingency Reserve Lower costs (pro-rata based on energy consumption) to loads with capacity less than or equal to 120 MW.

(2) Network Contingency Reserve Lower cost allocation as follows:

- apply a runway method to allocate the network component of Contingency Reserve Lower costs to loads in excess of 120 MW (if there is only one large load in excess of 120 MW, that load sets the Network Contingency and will bear 100% of Network Contingency Reserve Lower costs).

If a Load Contingency sets the Contingency Reserve Requirement in a trading interval, only the Load Contingency Reserve Lower cost allocation (1) process will be used.

Consultation Question 4:

Do stakeholders support the proposal to allocate Contingency Reserve Lower costs to loads using the proposed modified runway method?

Other ESS

The method to allocate Rate of Change of Frequency Service costs is out of scope for this review.

The pricing of System Restart service is primarily about cost recovery and is not directed at market efficiency. Therefore, the cost of System Restart services should be borne by loads.

Conceptual Design Proposal 5:

System Restart pricing is primarily focused on achieving cost recovery from beneficiaries, so the cost for System Restart services should be borne by loads, as per the current practice.

Consultation Question 5:

Do stakeholders support retaining the current System Restart cost allocation method?

Non-Co-Optimised ESS (**NCESS**) are either locational services used to substitute for network upgrades or services procured by AEMO.

Where Western Power procures the NCESS, these services are a substitute for network investments, so it is appropriate for Western Power to recover these costs via network access charges

It is difficult, at this early stage, to attribute NCESS costs for services procured by AEMO to individual loads and/or generators and to provide a price signal for customers and/or generators to reduce the requirement for this type of service. As a result, the current objective of NCESS pricing is cost recovery so it is appropriate to recover the cost of the NCESS from loads (i.e., there are no obvious efficiency benefits with allocating this cost to generators or network service providers).

Conceptual Design Proposal 6:

Recovery of NCESS should occur as follows:

- where AEMO procures the NCESS, the NCESS costs should be allocated to beneficiaries of the services (Market Customers), given that the current focus of NCESS charges is cost recovery and not market efficiency; and
- where Western Power procures the NCESS, these services are a substitute for network investments, so it is appropriate for Western Power to recover these costs via network access charges.

Consultation Question 6:

Do stakeholders support retaining the current NCESS cost allocation method and to review this once a number of NCESS has been procured?

1. Introduction

Clause 2.2D.1(h) of the WEM Rules confers the function on the 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.

The Coordinator, in consultation with the MAC, is reviewing the allocation of Market Fees and Essential System Services (**ESS**) costs under clause 2.2D.1 of the WEM Rules. The Cost Allocation Review has made some preliminary findings and developed proposals for changes to the cost allocation processes, and the purpose of this paper is to seek feedback from stakeholders on the findings and proposals.

1.1 Background

During the Energy Transformation Strategy development and implementation process, some stakeholders identified issues with the allocation of Market Fees and ESS costs to Market Participants. However, time constraints during the Energy Transformation Strategy prevented the Energy Transformation Taskforce from fully addressing all of these concerns.

Further, the MAC maintains a Market Development Forward Work Program to track and progress issues that have been identified by stakeholders. Several issues on the MAC's Market Development Forward Work Program relate to the allocation of market costs.

Therefore, the Coordinator is undertaking the Cost Allocation Review, in consultation with the MAC, to review of the allocation of Market Fees and ESS costs to Market Participants.

The MAC has established the Cost Allocation Review Working Group (**CARWG**) to assist with the review.

The Cost Allocation Review is being conducted in four steps:

- Step 1 policy assessment;
- Step 2: practicality assessment;
- Step 3: methodology development; and
- Step 4: proposed rule changes.

Further information on the Cost Allocation Review can be found at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group, including the detailed Scope of Works for the review, the Terms of Reference for the CARWG, and meeting papers and minutes for all CARWG and relevant MAC meetings.

1.2 Fees and Charges in Scope

The fees and charges for market services, and co-optimised and other ESS that are in scope include:

Market Fees

The Market Fees included in this review include:

- Market Fees to recover AEMO's costs for its market operation services, system planning services and market administration services;
- System Operation Fees to recover AEMO's costs for its system operation services;

- Regulator Fees to recover the Economic Regulation Authority's (**ERA**) costs for its monitoring, compliance, enforcement and regulation services, and
- Coordinator Fees to recover the Coordinator's costs for its functions under the WEM Rules plus the costs and expenses for the Chair of the MAC.

Co-optimised ESS Costs

From 1 October 2023, there will be five co-optimised ESS:

- Regulation services:
  - Regulation Raise;
  - Regulation Lower;
- Contingency Reserve services:
  - Contingency Reserve Raise;
  - Contingency Reserve Lower (**Contingency Reserve Lower**), and
- Rate of Change of Frequency (**RoCoF**) Control Service.

Other ESS Costs

- System Restart Service, and
- Non-Co-optimised ESS.

1.3 Out of Scope

The following issues are out of scope for the Cost Allocation Review:

- response that is mandated under the minimum standards in the technical rules (e.g., droop response);
- matters covered by the Reserve Capacity Mechanism Review (e.g., changes to peak demand or reductions of load as a result of the Individual Reserve Capacity Requirement (**IRCR**)); and
- cost allocation matters recently considered by the Energy Transformation Taskforce that have resulted in changes to the WEM Rules, such as changes to the runway method (apart from any known issues) or the RoCoF cost recovery method in Appendix 2B of the WEM Rules.

1.4 Purpose of this Paper

This consultation paper sets out the findings and proposals arising from steps 1-3 of the Cost Allocation Review.

The Coordinator will consider responses to this consultation paper in developing an information paper that will specify the detailed design for the allocation of Market Fees and ESS costs to Market Participants. Changes to the WEM Rules will be made based on the information paper.

This paper is structured as follows:

- Chapter 2 outlines the approach used for the qualitative and quantitative assessment of the options to allocate Market Fees and ESS costs;
- Chapter 3 assesses the options for allocating Market Fees and the rationale for recommending no changes to the allocation of Market Fees;

- Chapter 4 provides modelling of potential ESS requirements and costs to provide an indication of magnitude of the potential impact of any changes to the ESS cost allocation methods;
- Chapter 5 assesses the cost allocation options and proposes a preferred method to allocate costs for Regulation Raise and Lower services;
- Chapter 6 provides an overview of the cost recovery method for Contingency Reserve Raise services and recommends a change the application of the runway method in relation to aggregated facilities;
- Chapter 7 assesses the cost allocation options and proposes a method to allocate costs for Contingency Regulation Lower services; and
- Chapter 8 provides a qualitative assessment of the methods to allocate RoCoF Control services, System Restart services and Non-Co-Optimised Essential System Services (**NCESS**).

In parallel with this paper, Energy Policy WA (**EPWA**) is publishing a paper that reviews the cost allocation methodologies used in international energy markets. This international review was conducted by Marsden Jacob and is available at link.

1.5 Call for Submissions

This paper presents 6 recommendations on proposed methodologies to allocate Market Fees and ESS costs to Market Participants, and seeks stakeholder feedback on the recommendations.

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 5:00 pm WST on 9 February 2023. Late submissions may not be considered.

2. Approach to the Review

The objective of the Cost Allocation Review is to develop methods to align the allocation of Market Fees and ESS costs with the causer-pays principle, to the extent practicable and efficient.

2.1 Approach to Qualitative Assessment – Guiding Principles

The guiding principles for the Cost Allocation Review are that the Market Fee and ESS cost allocation methodologies should:

5. meet the Wholesale Market Objectives;[2]
6. be cost-effective, simple, flexible, sustainable, practical, and fair;
7. provide effective incentives to Market Participants to operate efficiently to minimise the overall cost to consumers; and
8. use the causer-pays principle, where practicable and efficient.

When it is difficult to attribute costs to "causers" of service requirements, it can be appropriate to allocate costs to "beneficiaries" of services. The MAC agreed that the "beneficiary-pays principle" should also be considered as a guiding principle in the appropriate circumstances.

The purpose of the qualitative assessment is to determine whether the current cost allocation methods used in the WEM are aligned with the above guiding principles. Where there is not good alignment, options were developed (modification of current methods or adoption of new methods) that may be more consistent with the guiding principles.

2.2 Approach to Quantitative Assessment – Modelling

Having identified options for cost allocation methods from the qualitative assessment, quantitative modelling was undertaken, where necessary, of the status quo and the identified options to assess the impacts of the options on Market Participants. Based on alignment with the guiding principles and quantitative analysis, this paper recommends preferred options for modifying or changing the relevant cost allocation methods.

---

[2] The Wholesale Market Objectives are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

3. Market Fees

3.1 Description of the Market Fees

Fees are levied to recover costs for a range of market services, as follows:

5. Market Fees to recover costs for AEMO's market operations, system planning and market administration services;
6. System Operation Fees to recover AEMO's costs for its system operation services;
7. Regulator Fees to recover the ERA's costs for its monitoring, compliance, enforcement, and regulation services; and
8. Coordinator Fees to recover the Coordinator's costs for its functions under the WEM Rules, including the costs and expenses for the Chair of the MAC.

Each Market Participant is charged a fee based on the Market Fee, System Operation Fee, Regulator Fee and Coordinator Fee rates and their sent out generation and/or load for all of its Registered Facilities and Non-Dispatchable Loads for all relevant Trading Intervals.

Table 1 shows the budget and fees for 2021/22 and 2022/23. Total fees are $1.4/MWh in 2022/23, which represents 0.5% of the annual bill of a residential customer in the South West Interconnected System (**SWIS**).[3]

Table 1: Market Fees

	Budget 2021-22	Budget 2022/23
Market Fee ($/MWh)	0.3800	0.4913
System Operation Fee ($/MWh)	0.5140	0.6646
Regulator Fee ($/MWh)	0.1951	0.1727
Coordinator Fee ($/MWh)	0.0750	0.0718
Total WEM fee ($/MWh)	1.1641	1.4004

Source: AEMO, Western Australia Wholesale Electricity Market 2022/23, AEMO Budget and Fees, June 2022

AEMO's revenue requirement has increased from $30.8 million in 2021/22 to $41.9 million in 2022/23, which reflects the recovery of a revenue deficit in 2021/22 ($5 million) and additional operating expenditure to accommodate the WEM Reform program ($6.0 million) in 2022/23.[4]

3 Calculated by Marsden Jacob 2022.

4 AEMO, Western Australia Wholesale Electricity Market 2022-23, AEMO Budget and Fees, June 2022.

3.2 Qualitative Assessment

3.2.1 Who should pay Market Fees?

The cost of market services does not vary significantly with sent out generation and/or load, or the number of Market Participants. Many of these costs are fixed and are determined by factors outside of the control of retailers and generators. As indicated in the international review,[5] costs for market services are primarily a function of the initial market design (i.e., number of participants, market complexity and market maturity).

These costs may increase due to energy reforms that are necessary to permit more Variable Renewable Energy (**VRE**) pant, storage facilities, and Distributed Energy Resources (**DER**) to participate in the WEM (e.g., the reserve capacity mechanism and the energy and ESS markets).

Market Participants can be regarded as “causers” of the requirement for services provided by AEMO, the Coordinator and the ERA. Market Participants interact with AEMO via formal participation in market mechanisms, as well as making inquiries and participating in market reviews and rule change processes.

The direct costs associated with managing an additional Market Participant’s market interactions and inquiries is relatively low given that the majority of AEMO costs are associated with building and maintaining market systems, and refining and updating processes and procedures.

Market Participants can also be regarded as “beneficiaries” of services provided by AEMO, the Coordinator and the ERA, as their participation in the market mechanisms allows them to earn revenue and provides them with the potential to make commercial returns.

The ultimate beneficiary of the services provided by AEMO, the Coordinator and the ERA are end customers, who are provided with affordable and reliable electricity. End customers are not Market Participants, but represented in the WEM by Market Customers.

Given that Market Participants can be regarded as both a “causer” and “beneficiary” of market services, most international jurisdictions levy fees and charges on Market Participants to recover of market service costs (e.g., WEM, PJM, NEM and I-SEM). In the NEM, this will also include Transmission Network Service Providers (**TNSP**s). In some markets, charges are only levied on Market Customers (or load servicing entities) and are not levied on Market Generators or TNSPs (e.g., CAISO, ERCOT, and Great Britain).

Some guidance on who should pay Market Fees can be obtained by considering the purpose of allocating Market Fees.

- If efficiency is the primary concern for the allocating Market Fees, then the fees should send an effective signal for a Market Participant to optimise their use of the market services provided by AEMO, the Coordinator and the ERA. This approach is unlikely to change the use of the market services given that these fees are significantly lower than other costs, and that Market Participants often have no choice but to use the services of AEMO, the Coordinator and the ERA.

[5] Marsden Jacob Associates Pty Ltd, Cost Allocation Review, International Review of Cost Allocation Methodologies, December 2022, p.63.

- If efficiency is not the primary concern, then the primary purpose of the fees is cost recovery. Ofgem (UK) makes the following observation:

  "it is not feasible to charge any of the components of balancing services in a more cost-reflective and forward-looking manner that would effectively influence user behaviour that would help the system and/or lower costs to customers. Therefore, the costs included within balancing services charges should all be treated on a cost-recovery basis."[6]

This led the First Taskforce on Balancing Service Use of System (**BSUoS**) Charges (UK)[7] to conclude that the purpose of BSUoS is cost-recovery and, as such, it should be paid by final consumers based on gross MWh.[8]

The Second BSUoS Taskforce provided further rationale for this decision:

> *"Given BSUoS charges are cost recovery charges, it is not efficient to recover part of it via generation, because doing so means the costs are passed through into wholesale costs, which includes unnecessary risk premium and transaction costs."*[9]

While this mainly related to the level of system services prices (e.g., frequency regulation) and not National Grid costs, the point is relevant.

A merchant generator with no bilateral Power Purchase Agreement (**PPA**) with other Market Participants would need to include Market Fees in its Balancing Market/Short Term Energy Market (**STEM**) offers. The merchant generator can then avoid the charges by not generating.

Other generators may recover Market Fees via their PPAs. If Market Fees are not explicitly passed through via the PPAs, then the generator will need to incorporate Market Fees in its Balancing Market/STEM offer in the same way as a merchant generator.

It could be argued that it is not appropriate to levy fees on generators and network operators if these costs will be passed through to retailers by generators via PPAs, and by Western Power via regulated network access tariffs. The basis for this argument is that retailers would ultimately bear this cost, but the fees would be imposed across multiple Market Participants, which may be inefficient. It may be simpler to allocate all Market Fees to Market Customers, who would then include them in the end customers' electricity bill.

3.2.2 Is allocating Market Fees based on Grid MWh Equitable?

Market Fees in the WEM are recovered based on metered generation or loads ("Grid MWh"). Therefore, the level of cost recovery is proportional to energy generated or consumed. In effect, larger Market Participants pay more than smaller Market Participants. Charging on this basis may create several potential inequities in cost allocation:

- A Market Generator with a portfolio of peaking and mid-merit plant with relatively low capacity factors (<30%) will pay less than a Market Generator with base load generation (capacity factor ≥ 50%). However, it is unlikely that the costs of AEMO, the Coordinator or the ERA will vary with the type of generator installed or the capacity factor of each generation type. To overcome this inequity, the NEM uses a combination of Grid MWh and Sent Out Capacity (MW) to recover costs from Market Generators.

6 http://www.chargingfutures.com/media/1330/balancing-services-charges-task-force-draft-report.pdf

7 BSUoS charges includes ancillary services and Market Fees.

8 Gross MWh includes energy consumed or supplied from the grid and behind the meter (i.e., includes rooftop PV generation).

9 http://www.chargingfutures.com/media/1477/second-balancing-services-charges-task-force-final-report.pdf

- Market Customers are allocated Market Fees on a Grid MWh basis which, if passed on to final customers, may add to an incentive for energy efficiency or the installation of DER. This may create an inequity between Market Customers depending on whether their final consumers have DER. To overcome this inequity, the NEM uses a combination of Grid MWh and the number of connection points (or NMIs) to ensure a more equitable level of cost recovery across different types of final customers.

To address the inequity between large and small end customers, and end customers that have low grid consumption due to DER, some jurisdictions have considered using gross MWh (or MW) as the billing determinant for Market Customers. Gross MWh would include energy generated behind-the-meter (**BTM**) plus grid imports. This was considered for the NEM and is being implemented in Great Britain by the National Grid. However, the current metering in the SWIS does not allow Western Power or AEMO to measure BTM generation, so this cannot be used to allocate Market Fees. Alternative or approximate measures could be used, such as installed capacity of DER or the IRCR of customers. This is discussed further in Section 3.3.

3.2.3 Assessment of the Current Market Fee Allocation Method

The current mechanism for allocating Market Fees is assessed against the guiding principles as follows:

- The current Market Fee allocation method is consistent with the principles of cost effectiveness, simplicity and practicality, but may have fairness concerns (see section 3.1.2).
- It is unlikely that levying Market Fees on Market Generators or Market Customers would cause any substantial efficiency loss or gain. Market Fees are low relative to other costs incurred by generators and retailers and the method for allocating Market Fees is unlikely to deter market entry, reduce generation output or encourage customers to reduce consumption.
- To some extent, levying Market Fees on both Market Generators and Market Customers is consistent with the causer-pays and beneficiary-pays principles, in that AEMO, the Coordinator and the ERA will incur costs from their interactions with both types of Market Participants. However, the direct costs associated with interacting with Market Participants is likely to be relatively low compared to the fixed costs (labour, management and systems) of AEMO, the Coordinator and the ERA.
- The current method favours particular Market Customers (retailers with a higher proportion of customers with DER) and Market Generators (generators that do not have high capacity factors based on technology type) over others and this may have little to do with cost attribution.

These shortcomings with of the Market Fee recovery method suggest that alternative allocation methods should be considered to aim at achieving a more equitable allocation of costs.

3.2.4 Options for Cost Recovery

Table 2 lists three Market Fee allocation options that were developed, aimed at overcoming the shortcomings of the current allocation method. Table 2 also assesses the consistency of each option with the causer-pays principle and indicates the potential advantages and disadvantages of each option.

Table 2: Assessment of Market Fee Options

Option	Billing Determinants	Consistency with Causer-Pays	Advantages / Disadvantages
Current WEM Method	Metered Schedule for all of the Market Participants' Registered Facilities and Non-Dispatchable Loads for all Trading Intervals for the day. Effectively a 50% split between Market Generators and Market Customers.	**Medium** Both Market Generators and Market Customers use the services provided by AEMO, the Coordinator and the ERA. Cost allocation is based on Market Participants' generation and consumption, which may not be a driver of market services costs.	• By charging on the basis of MWh generated or consumed, Market Customers that have a higher proportion of BTM generation and storage (lower Grid MWh consumption), and/or generators with lower capacity generators, are effectively able to avoid some Market Fees (fairness considerations). • Zero additional implementation costs.
Proposed NEM Method	70% of directly attributable costs are split between Market Generators, Market Customers and TNSPs based on directly attributable costs, and unattributable costs are allocated to Market Customers. For Market Generators: • 50% charged on capacity (MW); and • 50% on Grid MWh. For Market Customers: • 50% based on Grid Demand MWh; and • 50% based on number of Connections.	**High** Attempts to attribute costs to Market Participants based on their use of market services.[10]	• Addresses under-recovery of costs from low-capacity generators and Market Customers with a high proportion of BTM generation and storage through application of capacity charges (on generators) and connection charges (on Market Customers). • Implementation costs are unknown.

10 To assist in the allocation of core NEM costs to participants, AEMO undertook a survey of its Senior Managers who were tasked with allocating their Division's costs to participant classes on the basis of time of interaction and involvement with specific participant classes.

Option	Billing Determinants	Consistency with Causer-Pays	Advantages / Disadvantages
WEM Hybrid Method (new)	50% split between generators and loads For Market Generators: • 50% charged on Maximum Sent Out Capacity (MW); and • 50% on Grid MWh. For Market Customers: • 50% based on Grid Demand MWh; and • 50% on IRCR (MW).	**High** Attempts to attribute costs to Market Participants based on their use of market services.	• Addresses under-recovery of costs from low capacity generators and Market Customers with a high proportion of BTM generation and storage through application of capacity charges (on generators) and IRCR charges (on Market Customers). • Potentially significant implementation costs.[11]
Market Customer Only Method	All fees allocated to Market Customers with: • 50% based on Grid Demand MWh and 50% on IRCR (MW).	**Low**	• Based on the premise that there are few efficiency gains in levying fees on generators, who will pass these costs onto retailers and major customers via wholesale contracts (see section 3.2.1). • Some small administrative efficiencies with only placing burden on retailers rather than all Market Participants. • Potentially significant implementation costs.[12]

Source: Marsden Jacob 2022

Data is available to AEMO to apply each cost allocation option.

3.3 Impact of Fee Allocation Options on Market Participants

Table 3 provides an assessment of the impact of each of the Market Fee allocation options on Market Generators, Market Customers and Western Power for 2022/23, including the impact of levying fees only on Market Customers who then pass the fees through to final customers.[13]

11 A Market Participant indicated at the MAC meeting on 11 October 2022 that its costs to implement the WEM Hybrid Method would be around $100,000, which included billing changes, reconciliation tools and legal costs for amending contracts. If each major gentailer (Alinta, Synergy, Perth Energy, Bluewaters and ERM) incurred costs of this magnitude and all small retailers and independent generators incurred costs of about $15,000, then costs for market participants would be in the order of $900,000. Costs for AEMO to develop and implement the WEM Hybrid Method would likely result in total costs to implement the WEM Hybrid Method in excess of $1 million.

12 Costs to implement the Market Customer Only Method would likely be similar to the costs to implement the WEM Hybrid Method.

13 Final customers will ultimately bear the majority of Market Fees levied on Market Generators and Market Customers, as retailers will pass on these costs to customers via electricity bills. Table 3 only considers the

Table 3: Indicative Impact of AEMO Market Fees on Market Participants by Type

	Current WEM Method	Proposed NEM Method	WEM Hybrid Method	Market Customer Only Method
Cost Allocations by Participant Type				
Wholesale Participants	$20,950,298	$16,395,587	$20,950,149	$0
Market Customers	$20,950,298	$20,371,780	$20,950,000	$41,900,000
Western Power	$0	$5,132,750	$0	$0
Total	$41,900,596	$41,900,117	$41,900,149	$41,900,000
Cost Allocations to Market Generators				
Synergy	$8,095,565	$6,713,114	$8,577,963	$0
Alinta	$3,496,297	$2,855,362	$3,648,559	$0
Other	$9,358,436	$6,827,110	$8,723,627	$0
Total	$20,950,298	$16,395,587	$20,950,149	$0
Cost Allocations to Customer Type[14]				
Residential (no BTM DER)	$9.58	$13.40	$12.92	$25.84
Residential (3 kW Rooftop PV)	$7.14	$12.23	$11.71	$23.42
Residential (5 kW Rooftop PV)	$3.88	$10.66	$10.09	$20.19
Small Business (no BTM DER)	$25.81	$21.22	$32.04	$64.08
Small Business (10 kW Rooftop PV)	$12.96	$15.03	$25.68	$51.35
Large Commercial (no BTM DER)	$6,278.87	$3,033.00	$5,993.00	$11,986.01
Large Commercial (250 kW Rooftop PV)	$6,122.57	$2,957.72	$5,843.82	$11,687.64

Table 4 presents the indicative impact of the alternative cost allocation options for a selection of generators.

Table 4: Cost Allocation by Cost Recovery Method and Generator

Participant	Plant_ID	Annual GWh	Maximum Capacity (MW)	Capacity Factor	Current WEM Method	NEM / WEM Hybrid Method
ALBGRAS	ALBANY_WF1	57.51	21.60	0.30	67,762	$70,902
ALBGRAS	GRASMERE_WF1	43.23	13.80	0.36	50,939	$49,122
ALINTA	ALINTA_PNJ_U1	667.22	143.00	0.54	786,085	$638,140
ALINTA	ALINTA_PNJ_U2	545.29	143.00	0.44	642,435	$566,315
ALINTA	ALINTA_WGP_GT	32.82	196.00	0.02	38,671	$355,273
ALINTA	ALINTA_WGP_U2	26.68	196.00	0.02	$31,429	$351,651
ALINTA	ALINTA_WF1	304.62	89.10	0.39	$358,887	$332,158
ALINTA	BADGINGARRA_WF1	582.34	130.00	0.51	$686,094	$565,862
ALINTA	YANDIN_WF1	808.63	211.68	0.44	$952,697	$839,161

allocation of Market Fees to Market Customers (first round impact), since Market Fees allocated to Market Generators may be included in wholesale prices with no transparent charge on customer bills.

14 Only considers the impact of Market Fees allocated to Market Customers and not the impact of charges on Market Generators and Network Businesses.

Participant	Plant_ID	Annual GWh	Maximum Capacity (MW)	Capacity Factor	Current WEM Method	NEM / WEM Hybrid Method
COLLGAR	INVESTEC_COLLGAR_WF1	663.21	218.50	0.35	$781,364	$765,183
GRIFFIN2	BW2_BLUEWATERS_G1	1,352.60	217.00	0.71	$1,592,576	$1,168,720
GRIFFINP	BW1_BLUEWATERS_G2	1,482.45	217.00	0.78	$1,747,734	$1,245,797
MERREDIN	NAMKKN_MERR_SG1	0.40	92.60	0.00	$477	$158,952
MERSOLAR	MERSOLAR_PV1	263.63	100.00	0.30	$310,598	$326,696
MPOWER	AMBRISOLAR_PV1	2.12	0.96	0.25	$2,502	$2,896
MUMBIDA	NWF_MUMBIDA_WF1	205.20	55.00	0.43	$241,757	$215,146
NEWGEN	NEWGEN_KWINANA_CCG1	1,886.24	335.00	0.64	$2,222,288	$1,685,322
NGENEERP	NEWGEN_NEERABUP_GT1	226.38	342.00	0.08	$266,713	$719,533
SYNERGY	MUJA_G5	744.26	195.80	0.43	$876,851	$774,020
SYNERGY	MUJA_G6	731.29	193.60	0.43	$861,575	$762,611
SYNERGY	MUJA_G7	1,142.62	212.60	0.61	$1,346,191	$1,037,485
SYNERGY	MUJA_G8	1,232.00	212.60	0.66	$1,451,486	$1,090,132
SYNERGY	PINJAR_GT1	10.56	38.50	0.03	$12,438	$72,207
SYNERGY	PINJAR_GT10	52.04	118.15	0.05	$61,309	$233,160
SYNERGY	PINJAR_GT11	178.22	130.00	0.16	$209,974	$327,803
SYNERGY	PINJAR_GT2	5.97	38.50	0.02	$7,036	$69,506

Source: Marsden Jacob 2022

The impact of these Market Fee allocation methods on Market Generators is:

- the NEM Method and the WEM Hybrid Method would result in significant increases in the fees for peaking generators (NAMKKN_MERR_SG1, NEWGEN_NEERABUP_GT1, PINJAR units), and a slight reduction in fees for base load units (MUJA and the BLUEWATERS units);
- fees from intermittent generators would vary based on their capacity factor; and
- wind farms with relatively high capacity factors (>40%) would pay less under the WEM Hybrid Method, whereas those with lower capacity factors (between 25% and 37%) would pay more under the WEM Hybrid Method.

The impact of these Market Fee allocation methods on Market Customers is:

- Synergy will pay more with WEM Hybrid Method because its IRCR remains fairly constant despite a high solar penetration amongst residential customers, which reduces metered consumption; and
- retailers with a higher proportion of business customers will pay less under WEM Hybrid Method because their IRCR is proportionately lower than residential customers.

3.4 Treatment of Energy Storage Facilities

There was no discussion of cost recovery from storage facilities in AEMO's review of Market Fees in the NEM.[15] Energy storage facilities act as generators (discharge) and as loads (recharge). At the time of AEMO's review of Market Fees in the NEM, energy storage facilities had to register as Market Generators and as Market Customers, implying that energy storage facilities will effectively

15 AEMO, Electricity Fee Structures, Draft Report and Determination, A draft report and determination on electricity fee structures to apply to Participant fees from 1 July 2021, November 2020.

be charged twice for Market Fees. Such a practice is inconsistent with Wholesale Market Objectives, especially the principle of avoiding discrimination against particular energy options and technologies.

If open cycle gas turbines (**OCGT**) (fixed frame units) and battery energy storage systems (**BESS**) are regarded as highly substitutable, then it would be fair for each technology with the same capacity (MW) and the same capacity factor (%) to pay the same amount of Market Fees. However, under the NEM cost allocation method (2022/23 interim pricing), BESS would pay 154% more for market services compared to an OCGT plant with the same capacity and capacity factor, because the BESS would also incur Market Fees on its recharge (based on MWh withdrawal).

Storage and hybrid facilities will no longer need to register and participate in the NEM under two separate categories (Market Generator and Market Customer) under a Rule Change proposed by AEMO and endorsed by the Australian Energy Market Commission (**AEMC**).[16] AEMO indicated that there was an inequity in the treatment of large-scale storage facilities, with charges based on gross energy flows (recharge and discharge), while small storage facilities would only be charged on the basis of net energy flows. Instead, storage facilities will register in a new class (Integrated Resource Provider or IRP).

To avoid "double counting" of Market Fees, storage facilities should simply be treated as a Market Generator (now termed a Market Participant in the WEM) and its recharge energy ignored for the purposes of Market Fee allocation.

3.5 Costs and Priority of Implementing the WEM Hybrid Method

The CARWG gave close consideration to the WEM Hybrid Method and found that this method may have some equity benefits but that there could be substantial costs associated with implementing this method.

AEMO will have to develop new systems, policies and procedures to implement the new cost allocation method. In addition, Market Participants will have to implement changes to their settlement systems and change their wholesale contracts. Total costs for AEMO and Market Participants to implement the WEM Hybrid Method are likely in excess of $1 million.[11]

There is also a concern that amending Market Fee allocations are a low priority issue relative to the WEM reforms that are progressing to decarbonise the SWIS and maintain supply reliability. Implementing a new Market Fees allocation method does not increase the affordability, reliability or sustainability of electricity supply.

In conclusion, while adopting the Hybrid Method may provide for a more equitable allocation of Market Fees, no material benefit have been identified that would result from its implementation.

3.6 Views of the CARWG and MAC

CARWG and MAC members expressed a range of views on which approach should be adopted to allocate Market Fees. A number of Market Participants argued for retention of the existing cost

16 AEMC, Rule Determination, National Electricity Amendment (Integrating Energy Storage Systems into the NEM) Rule 2021, Proponent AEMO, 2 December 2021.

allocation method on the basis that costs would be incurred to implement new methods while the benefits of the methods have not been identified.

Other organisations (i.e., those representing consumers) had a preference for the WEM Hybrid Method, but some noted that "it might be difficult to support a change from the current method" unless there are demonstrated benefits.[17]

Some Market Generators indicated that generation is required to meet load requirements and, on this basis, "the causer-pays and beneficiary-pays principles suggest the Customer Only Method [is preferred], but the WEM Hybrid Method is the next best option because it reflects the changing nature of the system".[18]

3.7 Recommendation

While there was general agreement that the WEM Hybrid Method improved equity outcomes, these equity benefits will be a modest improvement given that Market Fees only make up 0.5% of a retail customer's electricity bill, and no efficiency benefits have been identified that offset the costs of implementation.

On the basis of the above analysis and views expressed at the CARWG and the MAC, it is recommended to retain the existing method for allocating market services costs and to ignore recharge energy when allocating Market Fees to storage facilities.

Conceptual Design Proposal 1:

- Retain the current method for allocating market services costs to Market Participants.
- Ignore recharge energy when allocating Market Fees to storage facilities.

Consultation Question 1:

Do stakeholders support:

(a) retaining the current method for allocating Market Fees to Market Participants; and

(b) ignoring recharge energy when allocating Market Fees to storage facilities?

17 Minutes from the CARWG meeting on 27 September 2022.

18 Ibid.

4. Essential System Services

4.1 Description of Services

ESS (previously known as Ancillary Services) are required to ensure a secure and reliable electricity supply. ESS are required to maintain system frequency due to a sudden large change in generation or load, as well as providing load following services to balance demand and supply within each 30-minute trading interval. The current Ancillary Services will be replaced by Frequency Control ESS (**FCESS**), and will include:

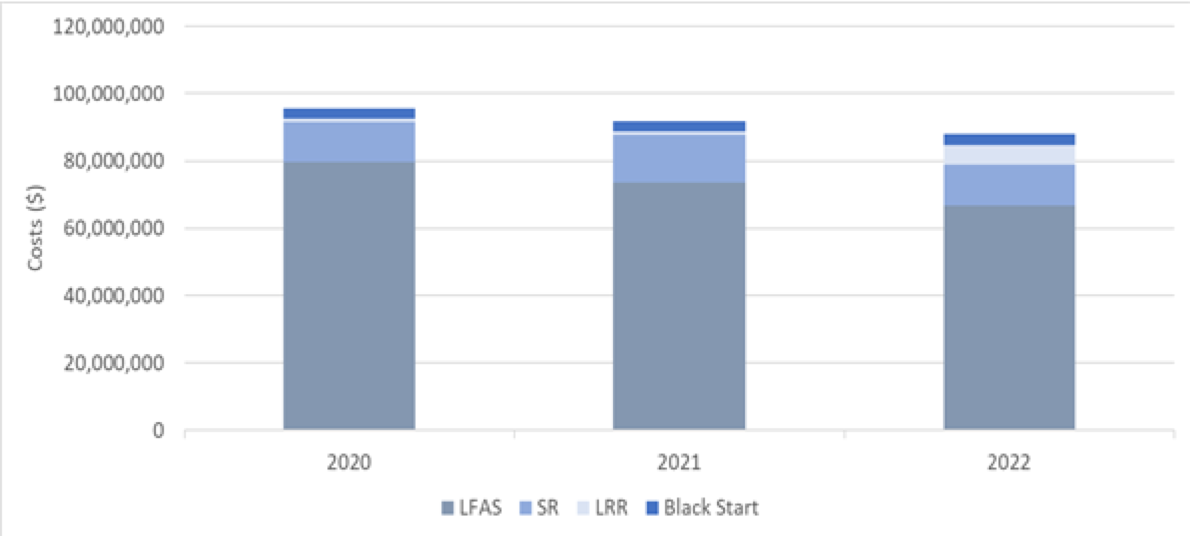
- Regulation Raise (currently referred to as Load Following Ancillary Services (**LFAS**) Up);
- Regulation Lower (currently referred to as LFAS Down);
- Contingency Reserve Raise (currently referred to as Spinning Reserve Ancillary Service or SRAS);
- Contingency Reserve Lower (currently referred to as Load Rejection Reserve (**LRR**)); and
- Rate of Change of Frequency (**RoCoF**) Control service (there is no current equivalent service).

Non-Co-optimised ESS includes:

- System Restart Service (or Black Start Service) is used to restart the system following a major blackout of the SWIS; and
- services that replaced the Dispatch Support Service and the Network Control Service.

Figure 1 indicates the Ancillary Service costs in the WEM for 2020 to 2022. These costs are currently around $90 million/year (or 5% of overall wholesale market revenues), with LFAS making up 80% and Spinning Reserve 14% of total ESS costs. LRR and Black Start services each make up 3% of total ESS costs.

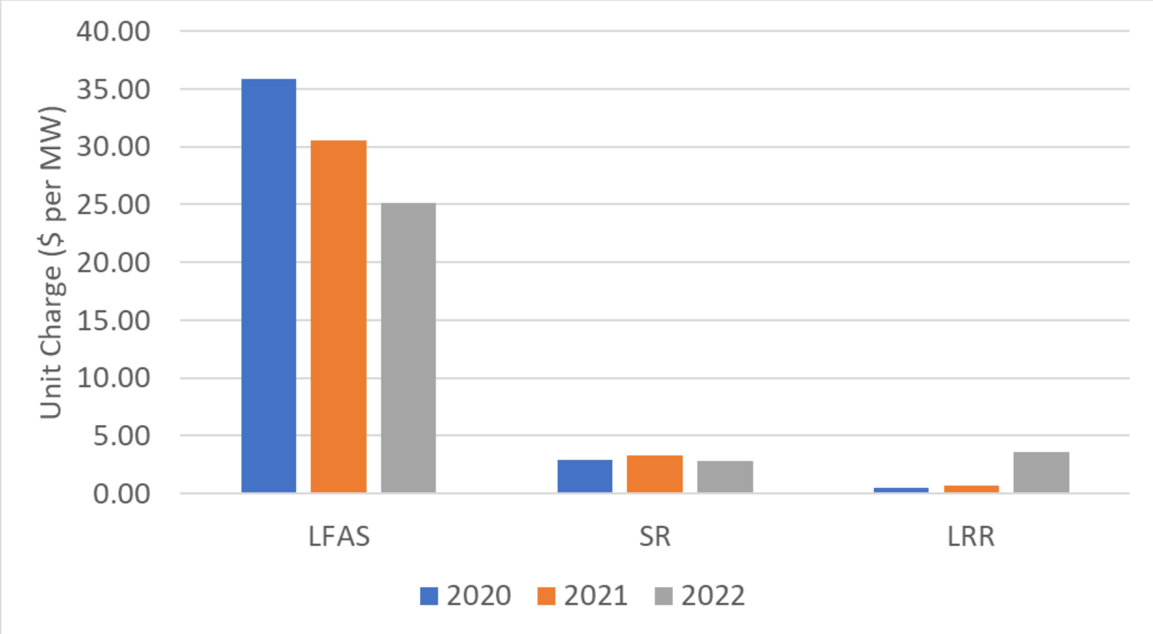
Figure 1: Ancillary Service Costs in the WEM



Source: System Management (AEMO), Ancillary Services Report for the WEM, June 2021 and June 2022, and MJA Analysis 2022

Figure 2 shows the unit costs for Ancillary Services. LFAS unit costs have fallen over time, while SRAS costs have remained stable and LRR costs increased appreciably in 2021/22.

Figure 2: ESS Costs by Service Type ($ per MW per trading interval)



Source: AEMO, Ancillary Services Report for the WEM, June 2021 and June 2022, and MJA Analysis 2022

4.2 Future Frequency Regulation and Contingency Reserve Raise and Lower Requirements

The section provides modelling of potential ESS requirements and costs to provide an indication of magnitude of the potential impact of any changes to the ESS cost allocation methods. This section presents only one possible scenario – the analysis is for illustration only and should not be relied on for any other purpose.

Using its PROPHET simulation model for the WEM, Marsden Jacob has estimated indicative future requirements for Frequency Regulation and Contingency Reserve Raise and Lower in the SWIS for 2022/23 to 2031/32, for a scenario that is consistent with the Expected Scenario in the AEMO Wholesale Electricity Market Electricity Statement of Opportunities 2022.[19]

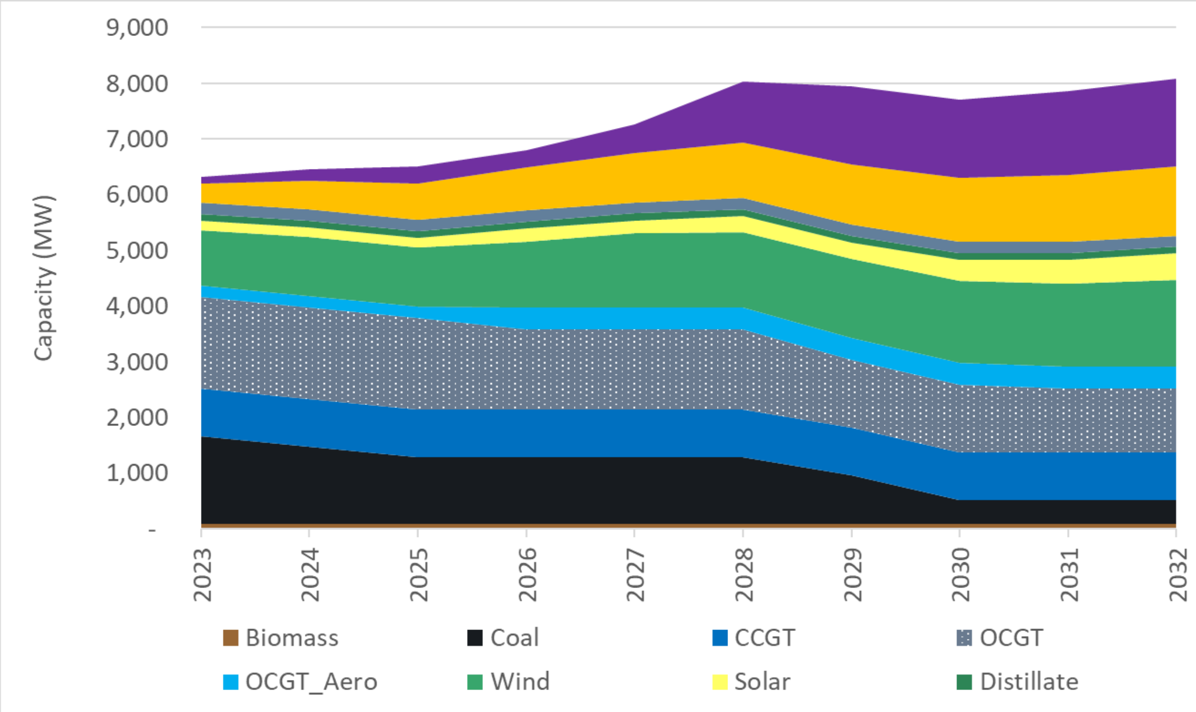
The key features of Marsden Jacob's scenario are:

- peak demand 10% probability of exceedance increases from 4,049 MW in 2022/23 to 4,376 MW in 2031/32;
- operational consumption is flat over the 10-year study period: 16,569 GWh in 2022/23 to 16,149 GWh by 2031/32 due to continued increases in rooftop PV in the SWIS from 3,867 MW in 2022/23 to 6,931 MW in 2031/32; and
- the net zero emissions by 2050 policy requires renewable energy penetration in the SWIS to increase to 60% by 2031/32, including rooftop PV and grid connected renewables – a doubling of renewable energy generation in the SWIS from 2022/23.

19 AEMO, 2022 Wholesale Electricity Market Electricity Statement of Opportunities, June 2022

Figure 3 shows the future capacity mix for one indicative scenario that was developed assuming that the WEM reliability criteria is met while the generation fleet is decarbonised.

Figure 3: Capacity in the SWIS Scenario



Source: Marsden Jacob 2022

The key changes in the capacity mix in this scenario are:

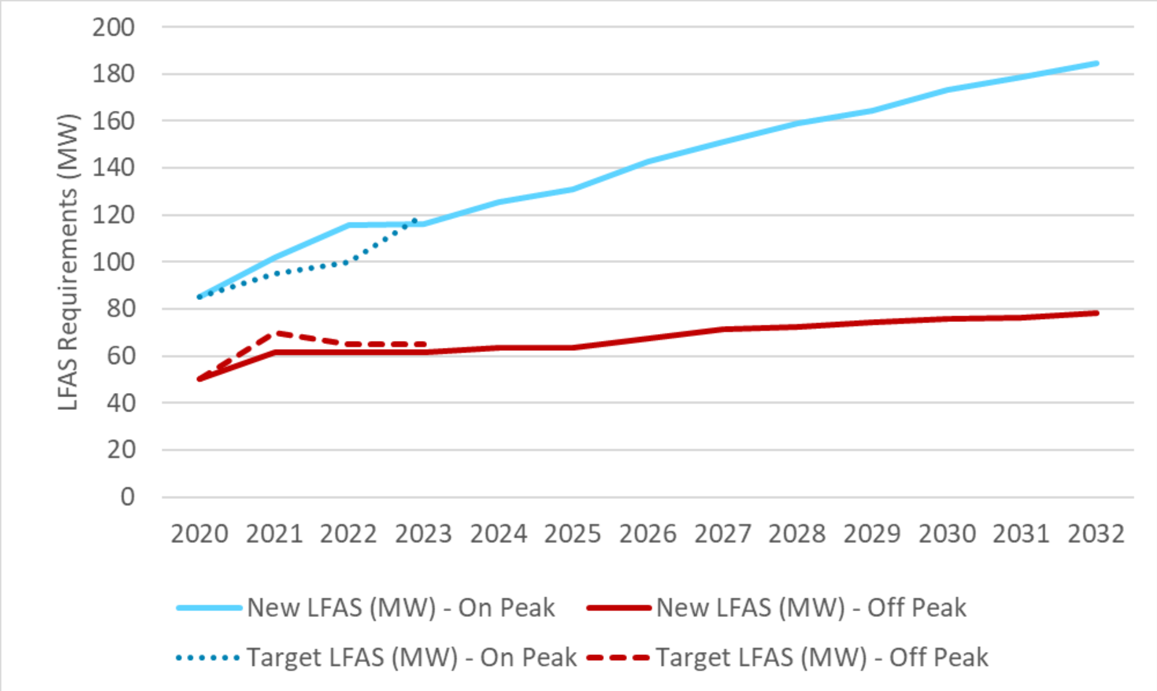
- grid connected storage increases from 110 MW in 2022/23 to 1,575 MW in 2031/32;
- wind generation increases from 997 MW to 1558 MW; and
- large-scale solar increases from 168 MW to 471 MW.

Under this scenario:

- LFAS requirements have already increased from 85 MW (daytime) and 50 MW (night time) in 2019/20 to 110 MW (daytime) and 80 MW (night time) in 2021/22 due to increased frequency excursions caused by the increasing penetration of intermittent resources on the system;[20] and
- Frequency Regulation requirements increase from 110 MW (on peak) and 80 MW (off peak) in 2021/22 to 185 MW (on peak) and 79 MW (off peak) in 2031/32, due to declining dispatchable generation and the continued increase in intermittent resources on the system, particularly solar generation (see Figure 4).

20 In 2021-22, LFAS Upwards/Downwards up to 110 MW between 5:30 AM and 8:30 PM, and 65 MW between 8:30 PM and 5:30 AM.

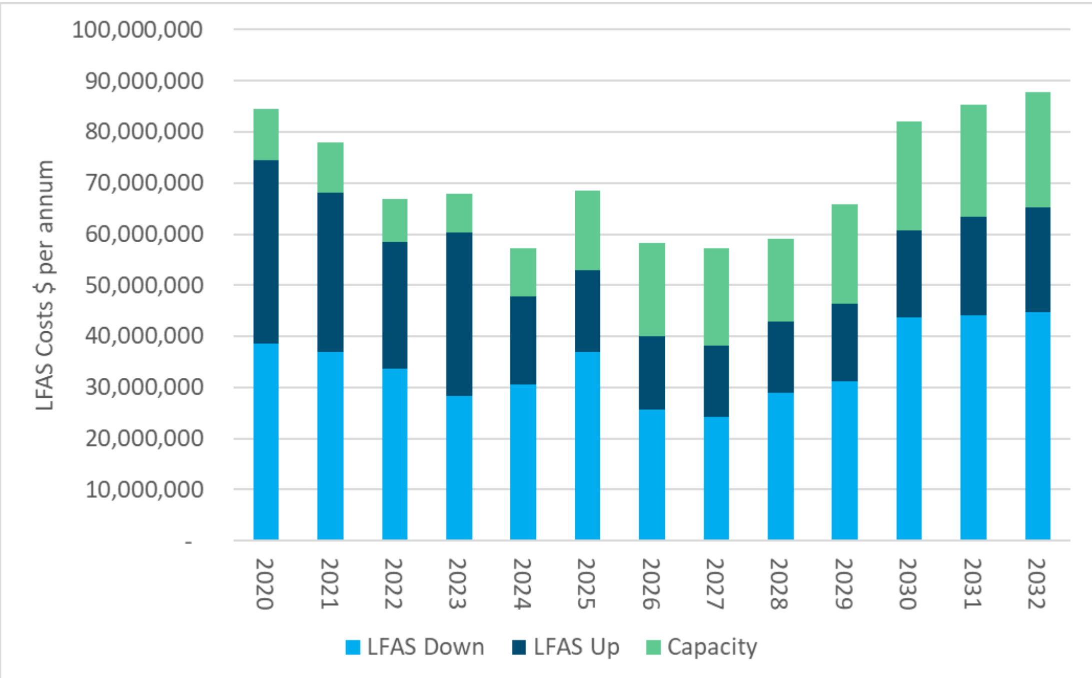
Figure 4: Frequency Regulation Requirements (MW)



Source: Marsden Jacob 2022

While the requirements for Frequency Regulation are increased under this scenario, overall costs may not increase because of the entry of storage in the LFAS market. Under this scenario, LFAS costs initially reduce with the entry of large scale batteries, but with the retirement of coal units (assumed to participate in future LFAS market), LFAS prices begin to increase towards the end of the late 2020s and early 2030s (see Figure 5).

Figure 5: Annual LFAS Costs (June 2022 dollars)



Source: Marsden Jacob 2022

Contingency Reserve Raise is set dynamically and is typically based on 70% of the largest operating generating unit, which will be 70% of the Collie Power Station in most trading intervals, at 223 MW. At other times Contingency Reserve Raise will be set on the basis of the Mid-West Area Reinforcement Network (**MARNET**) contingency (300 MW[21]) or on the basis of the required ramp rate for 15 minutes (240 MW).

Contingency Reserve Raise requirements for many periods could fall with the retirement of Collie (318 MW) and proposals for battery units of 250 to 300 MW.

The largest load in the SWIS is currently 120 MW at the Boddington Gold Mine and, with the introduction of a battery that is around 250 MW, the largest load on the SWIS will likely effectively double and Contingency Reserve Lower services could the increase from 90 to 230 MW.

21 Combination of simultaneous generation and load trips north of Northern Terminal following the loss of the 330 kilovolt (kV) line from Neerabup Terminal through to Three Springs Terminal, coupled with associated disconnection of rooftop distributed PV (10%).

5. Regulation Raise and Lower

5.1 Description of the Service

The need for Frequency Regulation can arise due to:

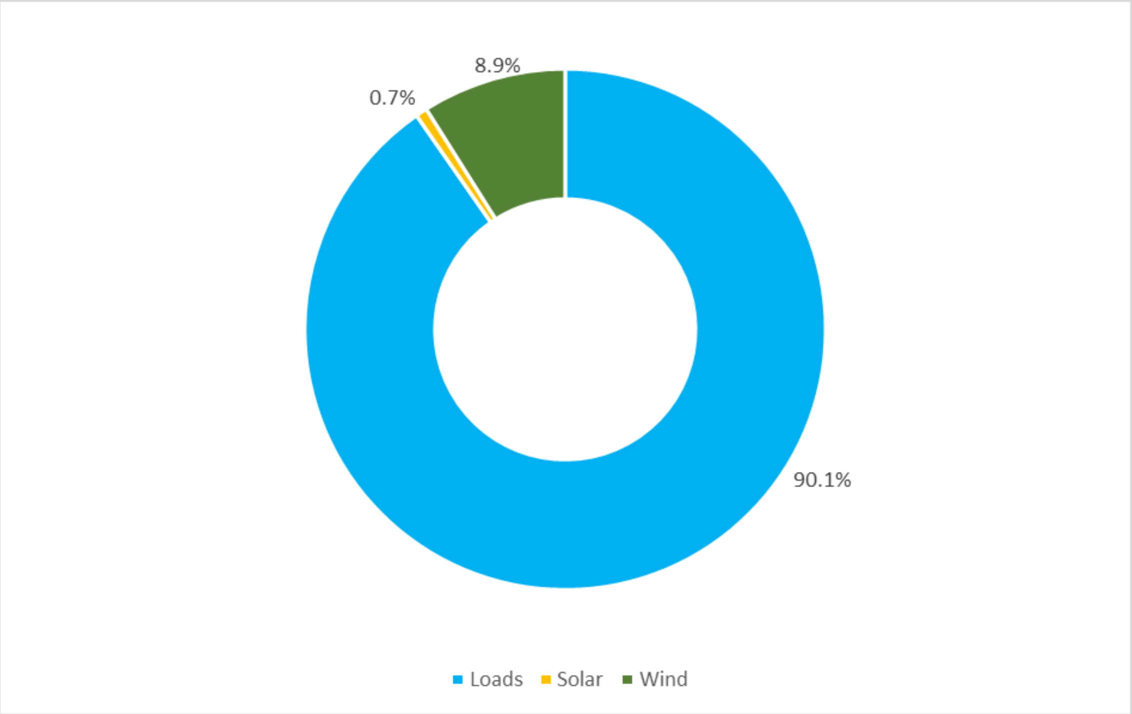
- deviations between actual and forecast generation from intermittent generation sources;
- scheduled generators and scheduled loads deviating from dispatch targets, other than in response to a frequency deviation;
- differences between aggregated customer load profiles and generator ramping profiles within a dispatch interval; and
- load forecast errors, which can include unexpected variations in the output of DER.

Currently, Frequency Regulation services (i.e., LFAS) in the WEM is procured every 30 minutes to enable “regulating” generators to respond to frequency deviations to maintain frequency within tolerance throughout the 30-minute period. Enablement prices are reflective of the net costs of generators, typically combined cycle gas turbine or OCGT plant having to operate out of the Balancing Market merit order to provide the service.

The costs of Frequency Regulation are recovered from Non-Dispatchable Loads, Semi-Scheduled Facilities (i.e., VRE plant), and Non-Scheduled Facilities in proportion to the absolute values of their metered generation or consumption in the relevant Trading Interval.

Figure 6 shows the current allocation of Frequency Regulation costs in the WEM. Given the penetration of VRE plant in the SWIS, 90% of the cost of Frequency Regulation is recovered from loads, but the level of cost recovery from loads will decrease as VRE plant penetration increases.

Figure 6: Frequency Regulation Cost Allocation Share – Current WEM Method



Source: Marsden Jacob 2022

The current WEM cost recovery mechanism does not provide any price signal to loads, VRE plant or scheduled generators to minimise the requirement for Frequency Regulation, which is contrary to the causer-pays pricing principle. The lack of meaningful price signals to Market Participants to minimise “causes” of frequency excursions in the WEM will not minimise the long-term cost of electricity supplied (inconsistent with the Wholesale Market Objectives and guiding principle 1) or provide effective incentives to Market Participants to operate efficiently to minimise the overall cost to consumers (guiding principle 3).

5.2 Options Identified

Four alternative methods for allocating frequency control costs in the WEM have been identified based on a better alignment with the causer-pays principle and more consistency with Wholesale Market Objectives. This includes the ability of the cost allocation method to provide price signals to Market Participants to minimise variations in generation/load, and reduce the future requirement for the service and the associated costs of providing the service.

5.2.1 The Current NEM Causer-Pays Method

In the NEM, AEMO enables Regulation FCAS to either raise or lower frequency to counteract small changes in power system frequency. Once enabled by Automatic Governor Control (**AGC**), Regulation FCAS is deployed as needed, based on the detected system frequency and accumulated time error of the system.

Contribution Factors are determined to apportion the costs of Regulation FCAS to Market Participants (i.e., Market Generators, Market Customers and Small Generation Aggregators) based on the assessed contribution of the plant/load at its connection point to variations in system frequency that cause the need for Regulation FCAS.

The calculations of Contribution Factors assess deviations from a reference trajectory, which is derived from expected dispatch or expected MW consumption. The deviations are calculated every four seconds and averaged over a dispatch trading interval (5 minutes).

The Contribution Factors are calculated for a region and are then normalised to produce NEM Contribution Factors for individual Market Generators based on their net performance, with residual demand Contribution Factors then calculated for Market Customers.

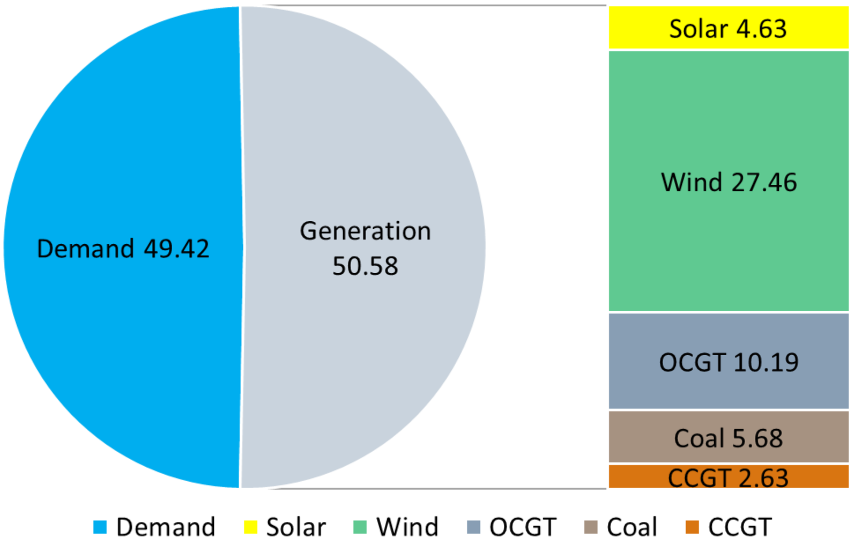
The purpose of these Contribution Factors is to attribute costs to parties that are responsible for frequency deviations and to provide incentives for them to change their behaviour to reduce Regulation FCAS costs. Such changes could include investment in better forecasting systems, co-locating storage facilities to smooth out variations in renewable plant output, or the use of storage to manage variations in loads.

FCAS market prices and Contribution Factors provide a strong signal for Market Participants (i.e., those responsible for generation and loads) to reduce frequency deviations and, in doing so, delivers potential efficiency benefits for the market.

Quantitative Assessment of the Current NEM Causer-Pays Method

Marsden Jacob applied the NEM Causer-Pays Method to WEM loads and generators for 1,000 simulations (using Monte Carlo analysis) to derive an average of frequency control cost recovery percentages for a 28 day period, as indicated in Figure 7.

Figure 7: Frequency Control Cost Recovery in the WEM using Current NEM Causer-Pays Contribution Factors



Source: Marsden Jacob 2022

Based on Marsden Jacob's analysis, frequency regulation costs would be split almost evenly between loads and generators if the current NEM Causer-Pays Method were used in the WEM. This is very different to the current allocation of frequency control costs in the WEM, which is 90% on loads and 10% on large-scale VRE generators.

When calculating frequency regulation cost recovery for each generation type, Marsden Jacob removed generation plant that is currently used to provide LFAS.

While solar farms demonstrate the highest variation between actual and target generation, given the relatively low penetration of large-scale solar farms in the WEM (140 MW), solar farms would only be allocated 4.63% of regulation costs in the 28 day period. However, this level of cost recovery is still significantly higher than their current frequency control cost recovery level in the WEM (0.7%).

Wind farms have more volatility than coal and gas plants and, given their high amount of installed capacity (1,034 MW), 27.5% of the costs would be allocated to wind farms. This is substantially higher than current regulation control cost recovery for wind farms (8.9%). Some of the most significant contributors to generation deviations were wind farms located in the North Country region (i.e., Badgingarra, Yandin and Warradarge).

Scheduled generators were also responsible for generation deviations and would be allocated around 18.5% of frequency control costs compared to none currently.

Marsden Jacob's analysis indicates that the current WEM method for Frequency Regulation cost recovery in the WEM over-recovers costs from loads and under-recovers costs from both intermittent and scheduled generators. This is inconsistent with the causer-pays principle, under which intermittent and scheduled generators should pay for the regulation services costs that they impose.

5.2.2 The Forecast Range Method

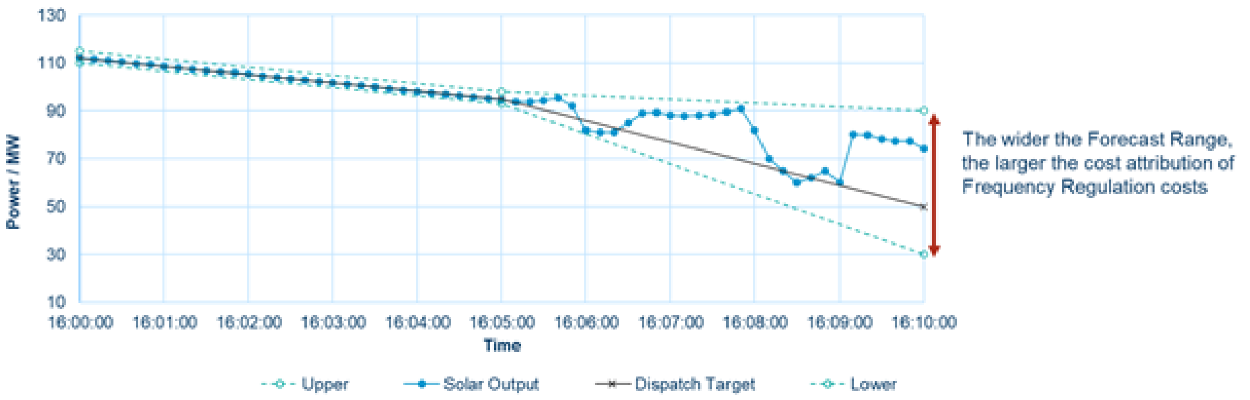
AEMO has suggested that ex-ante forecast ranges provided by Market Participants could be used to set the requirement for Regulation services and to allocate Regulation costs to Market Participants as an alternative to applying NEM Causer Pay factors.

AEMO suggested that the advantage of using ex-ante forecast ranges is that it would:

1. provide additional input to AEMO for establishing the Regulation quantity that needs to be procured in a trading interval. This would help align Regulation quantities with forecasted uncertainty;
2. provides input to a causer-pays method for recovering Regulation costs:
   - causers would be those setting the requirement ex-ante based on their projected forecast ranges (rather than ex-post by actual performance);
   - payment would be calculated as a proportion of total forecast ranges (see Figure 8);
3. help identify the "firm" capability of Intermittent Facilities to calculate reserves available for FCESS:
   - the lower bound of the range may be used as the upper limit for any FCESS reserves that may be made available by curtailing beneath that lower forecast range value (see Figure 9); and
   - if the WEM includes a ramping/reserve market in the future, generators providing forecast ranges can help identify the potential ramping availability of their Facility (e.g., if a wind generator is constrained down to provide FCESS, it has potential to ramp up quickly to meet future ramping or reserve requirements).

Figure 8 shows how the forecast range would be used to calculate the frequency regulation cost recovery factor for a solar plant. The forecast range in this example is small between 16:00 and 16:05 but increases after this due to uncertainty caused by weather patterns. Frequency Regulation cost recovery from the solar farm is lower when the solar farm is confident about its output but increases when its output is more uncertain.

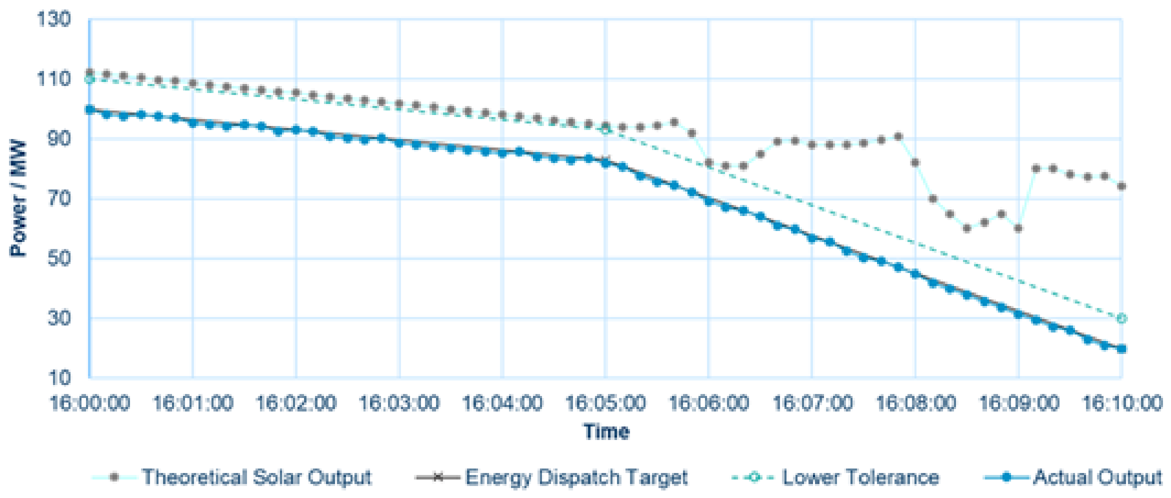
Figure 8: Using Forecast Range for Frequency Regulation Cost Recovery



Source: AEMO 2022

Figure 9 illustrates an example of a solar generator constraining its output below its theoretical output. As a result, it can potentially provide a Regulation Raise service up to the level that it is confident that it can produce in each period.

Figure 9: Solar Farm Providing Regulation Raise

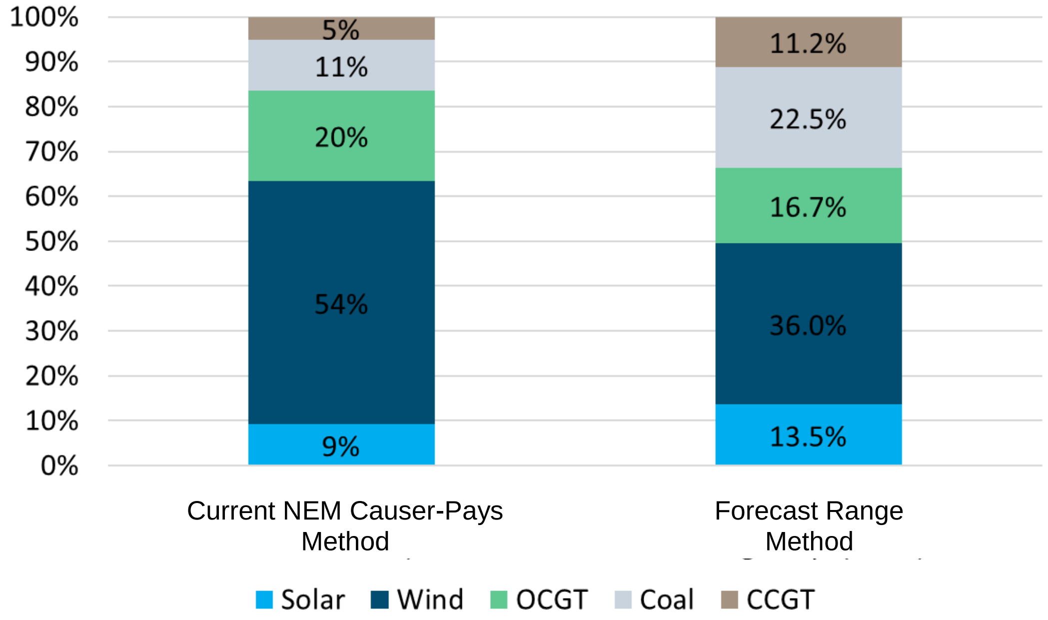


Source: AEMO 2022

Quantitative Assessment of the Forecast Range Method

Marsden Jacob determined the Contribution Factor for each technology type and compared the result with the WEM Contribution Factors calculated under the current NEM Causer-Pays Method (see Figure 10).

Figure 10: Frequency Regulation Cost Recovery Factors (%) for WEM under the Current NEM Causer-Pays and Forecast Range Method



Source: Marsden Jacob 2022

Under the Forecast Range Method, solar farms would make a higher contribution to the recovery of Frequency Regulation costs than under the current NEM Causer-Pays Method, while wind farms would make a smaller contribution (36%). This compares to 54% of total Frequency Regulation costs recovered from wind generators in the SWIS under the current NEM Causer-Pays Method. On the other hand, scheduled plant would make a higher contribution to Frequency Regulation costs under the Forecast Range Method compared to the current NEM Causer-Pays Method.

5.2.3 The New NEM Causer-Pays Method

The AEMC has approved a rule change to amend the current NEM Causer-Pays Method for FCAS cost recovery in the NEM to provide performance payments to Facilities that make positive contributions to improving system frequency during a trading interval, and AEMO is currently working on designing the implementation of the rule change.

The key elements of the new NEM Causer-Pays Method include:[22]

- Payments to support frequency performance will be made to Market Participants who obtain positive contribution factors in a trading interval. Contribution factors reflect the impact of generation and load on system frequency:
  - a positive contribution factor represents behaviour that helps to control system frequency and reduce a frequency deviation (from 50Hz); and
  - a negative contribution factor represents behaviour that contributes to the deviation of system frequency.

  The costs of frequency performance payments will be allocated to Market Participants who obtain negative contribution factors for that trading interval.
- The timeframes for the allocation of costs for the enablement of regulation services will be modified to better reflect the real-time use of regulation services (i.e., 7 day billing period replaces current 28 days billing period).

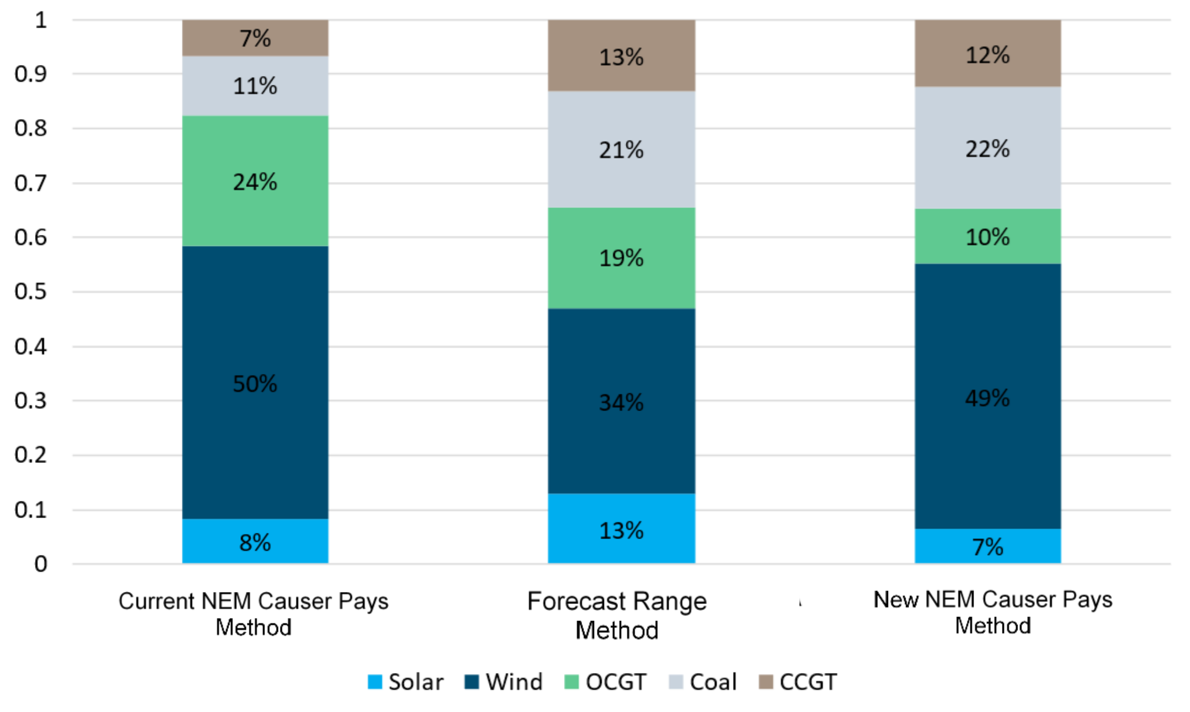
AEMO is continuing to develop the approach to implementing the New Causer-Pays Method in the NEM for commencement on 8 June 2025.

Quantitative Assessment of New NEM Causer-Pays Method

Figure 11 shows the contribution factors for the current NEM Causer-Pays Method, the Forecast Range Method and the new NEM Causer-Pays Method. The new NEM Causer-Pays Method is based on a sample day, so it has more variation than the other methods (both based on 28 days). In essence, the two NEM Causer-Pays Methods have similar outcomes, with higher costs recovered from wind farms and lower costs recovered from solar farms, compared to the Forecast Range Method.

[22] AEMC, National Electricity Amendment, Primary Frequency Response Incentive Arrangements, Proponent AEMO, 8 September 2022, p. iv.

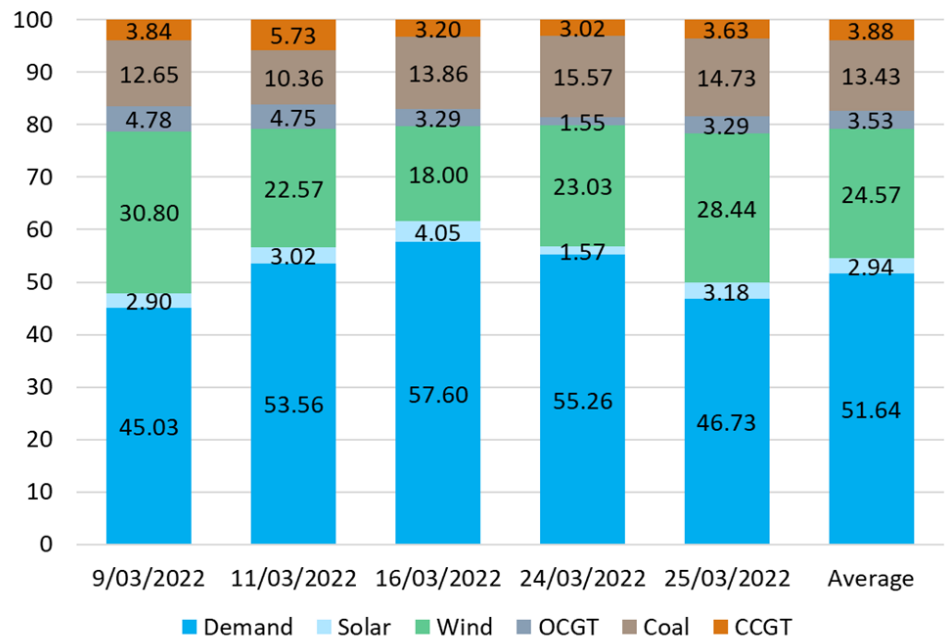
Figure 11: Frequency Regulation Cost Recovery Factors for the WEM under the NEM Causer-Pays (Existing and New) and Forecast Range Methods



Source: Marsden Jacob 2022

Figure 12 shows the results using the new NEM Causer-Pays Method for 5. There are significant variations in the contribution factors for solar farms (1.67-4.1%) and wind farms (18.0-30.8%) on various days in March 2022. Demand (or loads) have much more stable contribution factors (45.0%-57.6%) compared to intermittent plant in the SWIS.

Figure 12: Frequency Regulation Cost Recovery Factors (%) for the WEM under the New NEM Causer-Pays Method



Source: Marsden Jacob 2022

5.3 Benefits of the Alternative Approaches

Adoption of any of the three alternative methods discussed in section 5.2 for allocating Frequency Regulation costs in the WEM should incentivise intermittent and scheduled generators to consider at least the following strategies to minimise variations between their dispatch targets (or dispatch caps) and actual generation levels:

- improve forecasting of generation;
- installation of storage to ensure solar/wind generation is less variable; and/or
- for solar and wind generators, deliberately constraining generation levels below maximum potential and provide offers to provide Regulation Raise, noting that this will be considered in the context of the current price and the forward price curve for Large-Scale Generation Certificates (**LGCs**).

Adoption of these strategies could be an efficient response by generators to the imposition of cost-reflective frequency control pricing. Over time, as generators reduce variations between target/forecast and actual generation levels, loads will be likely to incur a higher proportion of frequency control costs because they will cause most of the frequency deviations. This may provide incentives for retailers and aggregators to encourage customers to install BTM batteries, thereby reducing the requirement for Regulation Raise services in the future.

However, the implementation of these methods raises a number of concerns for the WEM.

5.4 Concerns with Alternative Approaches

Discussion on the concerns with the alternative approaches to allocate Frequency Regulation costs in this section is limited to the new NEM Causer-Pays and Forecast Range Methods because the current NEM Causer-Pays Method is highly complex and is being replaced by the new NEM Causer-Pays Method in 2025.

5.4.1 The New NEM Causer-Pays Method

Under the new NEM Causer-Pays Method, Market Participants that provide Primary Frequency Response (**PFR**) are compensated for the costs of providing this service. In the WEM, the provision of PFR is a mandatory requirement under the WEM Rules and there are no plans to compensate Market Participants for meeting this requirement.

In addition, Market Participants are required to remain within their Tolerance Ranges (defined in WEM Rules) when generating and penalties apply if generation occurs outside those ranges.

In effect, the WEM already has a number of mechanisms to limit generation using imposed standards rather than market mechanisms.

The new NEM Causer-Pays Method provides payments to Market Participants that help contribute to frequency corrections, further incentivising participants to minimise generation and load deviations. This may result in a risk that Market Participants will ‘over-correct’ for potential frequency deviations and cause ‘actual’ frequency deviations that will need to be managed via further dispatch of Frequency Regulation services.

Further, the WEM is a small, highly concentrated market and the market-based new NEM Causer-Pays Method may create incentives for Market Participants to exploit their position to maximise financial returns. This could require additional market power mitigation arrangements to be implemented, which would add to the cost and complexity of the method, and may impact on the effectiveness of the incentives of the method to reduce Frequency Regulation costs.

5.4.2 The Forecast Range Method

Under this method, it is proposed that both regulation requirements and cost recovery will be influenced by ex-ante forecast ranges provided by Market Participants. Market Participants may be incentivised to under-forecast ranges to minimise their exposure to Frequency Regulation costs.

This will require implementing penalties if actual output exceeds the Forecast Range.

- If penalty payments are high, then Market Participants will be incentivised to over-forecast ranges, which has the potential to increase regulation requirements, resulting in higher costs to the market. To address this, AEMO would set Regulation requirements based on a variety of inputs (including the forecast ranges) and, if the forecast ranges are being over-estimated, would take this into account when setting the Regulation requirement.
- If penalty payments are low, then Market Participants will be incentivised to under-forecast ranges to reduce their exposure. AEMO would then be required to dispatch additional plant to manage frequency excursions because deviations in actual output are likely to be higher than forecast. Again, to avoid this, AEMO would have to consider the under-estimation of forecast ranges when setting Regulation requirements.

In effect, this method could result in incentives for Market Participants to influence market outcomes in their favour. As a result, AEMO may not get reliable forecast ranges from participants and will most likely have to rely on its own forecasts when establishing Regulation requirements.

The Forecast Ranges Method may not result in accurate attribution of Frequency Regulation costs if forecast ranges are under- or over-estimated by Market Participants.

EPWA is of the view that AEMO’s forecasting capabilities will need to improve in the future (through investment in better forecasting systems and methods) to help decrease future Regulation requirements.

5.4.3 Multiple Objectives of Alternative Methods

The above mentioned Frequency Regulation cost-recovery options have objectives in addition to the allocation of Frequency Regulation costs:

- the new NEM Causer-Pays Method – provides financial compensation for providing PFR and incentives for the operation of plant or loads that help correct frequency deviations; and
- the Forecast Ranges Method – provides incentives for better forecasting by Market Participants to minimise Regulation requirements and for intermittent plant to provide FCESS Raise Service.

However, there are existing market mechanisms in the WEM to ensure the provision of PFR (under the Generator Performance Standards) and to correct frequency deviations (through ESS Frequency Regulation, ESS Contingency Reserve and RoCoF).

Adding incentives to improve performance (minimising generation or load deviations) adds complexity, which may not be warranted in a cost allocation method.

A cost allocation mechanism for Frequency Regulation in the WEM only needs to:

- provide incentives for participants to minimise generation (or load) deviations;[23] and

[23] This is problematic for intermittent generators given variations in generation are caused by weather and only expensive options are typically available for intermittent generators to decrease the ‘natural variations’ in output (curtailing generation and foregoing energy and LGC revenue, or installing BESS).

- ensure that Market Participants that deviate from generation (or load) targets and add to the requirement for regulation services make an adequate contribution to Frequency Regulation costs.

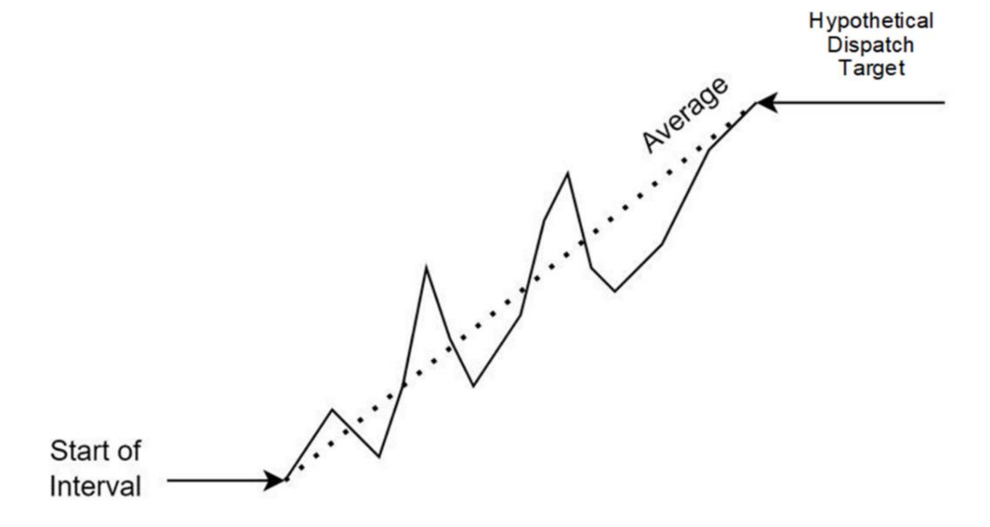
5.5 The WEM Deviation Method (Simplified Causer-Pays)

A simplified method for recovery of Frequency Regulation costs is to base cost recovery on deviations from average generation (or load) over a 5-minute dispatch interval in the WEM. This can be based on 4-second SCADA data and measuring actual deviations from a hypothetical linear dispatch target[24] that is calculated ex-post (i.e., average generation over a 5 minute dispatch period).

This would involve:

- estimating a hypothetical dispatch target for the plant in every 5-minute dispatch period based on 4-second SCADA data for a 5-minute dispatch interval (see Figure 13);
- calculating a linear ramp between dispatch targets matching 4-second SCADA data;
- estimating a standard deviation from the ramping target (or load) across a 30-minute trading interval (over 6 dispatch intervals);
- calculating and aggregating coefficients of variation (i.e., standard deviation divided by the average) for plant and loads and calculating the contribution factor (normalised) for each 30-minute trading period (must add up to 100%); and
- calculating the average contribution factor for a trading interval and apportioning the frequency regulation costs to the generator/load (note that use of a linear dispatch target takes into account different generation levels at the commencement of each dispatch period).

Figure 13: WEM Deviation Method Calculation



24 Intermittent generators in the WEM do not have dispatch targets and it is not intend to introduce dispatch targets in the WEM for this type of generation.

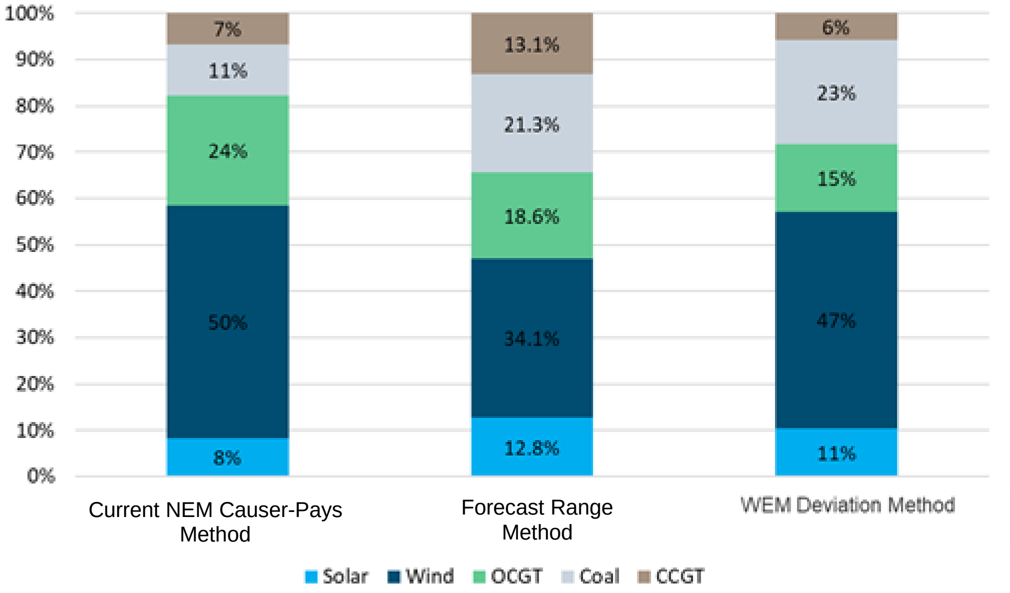
5.5.1 Assessment of the WEM Deviation Method

Marsden Jacob determined the Contribution Factor for each technology type using the WEM Deviation Method and compared the result with the Contribution Factors calculated for the current NEM Causer-Pays Method and the Forecast Range Method.

The WEM Deviation Method shows a similar trend to the current NEM Causer-Pays and Forecast Range Methods, with wind being the largest contributor to Regulation Raise cost recovery.

The split between loads and generation would be very similar to the current NEM Causer-Pays Method, as both use aggregation of errors (around 50% split between loads and generators under the WEM Deviation Method).

Figure 14: Contribution Factors for the WEM Deviation Method and Other Methods



Source: Marsden Jacob 2022

Table 5 outlines the pros and cons of the proposed WEM Deviation Method. In summary, the method is:

- simpler to implement;
- provides incentives for Market Participants to minimise deviations in generation and loads;
- minimises potential for gaming; and
- is more consistent with existing WEM frameworks (i.e., PFR and Tolerance Ranges).

While the WEM Deviation Method does not have the same level of accuracy as the new NEM Causer-Pays Method, which may result in less accurate cost attribution, it will result in significantly better cost attribution than the current WEM method.

Table 5: Pros and Cons of Proposed WEM Deviation Method

Pros	Cons
• Provides incentives for Market Participants to minimise generation and load deviations, acknowledging that loads and intermittent generators will not be able to correct deviations in many instances.	• Generation and load deviations may not always result in frequency excursions and costs being incurred to manage/correct frequency deviations.

Pros	Cons
• Loads and intermittent generators are likely to pay the most under this method. However, this has also been the result under the application of all other methods based on the causer-pays principle.	• Loads' and intermittent generators' response to price signals provided by the method could be limited by the high cost of better controlling load or intermittent generation, which implies that the overall efficiency benefits may be modest, even if cost attribution is consistent with 'causer-pays' principles.
• Relatively simple to implement and administer.	
• Provides little incentives for 'gaming' by Market Participants to avoid charges.	
• Avoids Market Participants nominating forecasting ranges or expected generation or load levels over a dispatch interval.	
• Is consistent with existing WEM frameworks (i.e., Tolerance Ranges, Generator Performance Standards, including requirements for PFR, etc.).	

5.6 Proposed Allocation Method

The alternative methods to allocate Frequency Regulation services costs attempt to attribute costs to the facilities/loads that impose risks and cause costs to be incurred in the WEM. These methods will provide incentives for participants to take action to reduce the incidence of Frequency Regulation costs via means such as better forecasting, installation of storage facilities, and intermittent generators providing ESS Raise services.

The WEM Deviation Method is preferred because:

- it is simpler to implement, especially compared to the new NEM Causer-Pays Method, which attempts to calculate contribution factors in real time;
- provides incentives for Market Participants to minimise deviations in generation and loads (similar to the other methods);
- does not provide incentives for 'gaming' by Market Participants to avoid charges, which may arise under the Forecast Range Method; and
- is more consistent with existing WEM frameworks (i.e., PFR, Tolerance Bands and FCESS).

Adoption of the new NEM Causers Pays Method would provide incentives to reduce Frequency Control requirements and costs, and would:

- create benefits for participants operating in both the WEM and NEM from having a common approach across the two jurisdictions;
- create cost savings for AEMO in developing and maintaining systems across both the WEM and NEM; and

- provide more frequent price signals (7-day settlement) to Market Participants, which allow them to adjust their forecasts or operations to minimise their net liability for Frequency Regulation costs.

In the longer term, the new NEM Causer-Pays Method could be considered after it is introduced in in the NEM in 2025 and has operated for a period (e.g., an assessment in 2027 with a possible implementation in the WEM in 2028/29).

Conceptual Design Proposal 2:

- Implement the WEM Deviation Method to allocate Frequency Regulation costs in 2024/25, following the implementation of the new WEM arrangements on 1 October 2023, subject to a cost/benefit assessment.
- Reassess adoption of the new NEM Causer-Pays Method to allocate Frequency Regulation costs in 2027, for potential implementation in 2028/29.

Consultation Question 2:

Do stakeholders support:

(a) adoption of the WEM Deviation Method in 2024/25 to allocate Frequency Regulation costs, subject to a cost/benefit analysis; and

(a) reassessment of the New NEM Causer-Pays Method to allocate Frequency Regulation Costs in 2027, for potential implementation in 2028/29?

6. Contingency Reserve Raise

Contingency Reserve Raise is required to cover the risk of a material decrease in power system frequency due to a generation facility tripping or loss of network assets (excluding an unexpected increase in load).

The Energy Transformation Taskforce initially recommended adopting the full runway method to allocate Contingency Reserve Raise costs to generators but later recommended the continued use of a modified runway method – the method currently used to allocate Spinning Reserve Costs.

Under this method, the costs of contingency raise services are allocated based on the degree to which a Market Participant's plant contributes to the size of the largest credible risk and, therefore, the overall need for contingency raise services. Costs will be allocated on a five-minute basis using the MW quantity of energy and frequency control ESS (Regulation and Contingency Reserve) cleared by the dispatch engine, for all generation facilities above 10 MW.

Changes to the runway method are out of scope for this study, apart from any known issues.

In applying the runway method, charges are levied on Facilities that have a single network connection point, although they may have one or more generation units behind the network connection.

Core to application of the runway method is determining the Facility Risk value for a Registered Facility.[25] The Facility Risk value measures the likelihood that the Facility will not be operational in a trading interval and is a function of Facility capacity (FacilityMW). Facilities with the highest FacilityMW in a trading period will be allocated the highest amount of Contingency Reserve Raise costs in that trading interval.

Facilities are typically single dispatchable (or controllable) units with a separate network connection point.

However, a power station may comprise a number of facilities, whereby each facility is separately dispatchable and has a separate network connection point. For example, the Bluewaters Power Station comprises of two separate dispatchable units. For the purposes of Contingency Reserve Raise cost recovery, each unit would be regarded as an Applicable Facility and the maximum FacilityMW in a trading interval is 217 MW for each unit.

In other cases, despite the power station having multiple units, the maximum FacilityMW could be the sum of the capacity of the multiple units. For example, the NewGen Neerabup power station is comprised of two 173MW OCGTs. The Facility is registered as a single Facility of 342 MW. Despite the plant having two dispatchable units for the purposes of WEM participation, the plant is treated as a single dispatchable unit. This implies that the maximum FacilityMW in a trading interval will be 342 MW.

25 A Registered Facility becomes an Applicable Facility for the purposes of Contingency Reserve Raise cost recovery if it exceeds 10 MW. A Facility in the WEM can be:

- transmission or distribution connected;
- a combination of technology types at a network connection point (e.g., wind, solar, battery and a gas generator);
- one or more loads at a network connection point; or
- a small aggregation of DERs at a single Electrical Location.

The Electrical Location of a Facility denotes the transmission zone substation at which the Facility's Transmission Loss Factor is defined. Hence, Facilities with the same Electrical Location would have the same Transmission Loss Factor.

All intermittent Non-Scheduled Facilities are currently regarded as a single Facility. While a solar farm may have several groups of inverters that are separately controlled (separate control board) behind a network connection point, they may have only one network connection point that all sets of independently controlled inverters may use. Hence, despite there being separate units behind the connection point, the maximum FacilityMW will be the sum of the maximum capacity of the separate groups of inverters.

Other configurations are possible, such as in the case of the Collgar Wind Farm. The total installed capacity of the wind farm is 218.5 MW, but it comprises two sets of controllable inverters (109 MW), each with their own separate network connection. Because the Facility is currently registered as a single Facility, its maximum FacilityMW will be 218.5 MW. However, the largest credible supply contingency for this Facility is only likely to be 109 MW (i.e., electrical failure for a single set of inverters, or failure at the network connection). For the purposes of applying the runway method for Contingency Reserve Raise cost allocation, basing the maximum FacilityMW on the capacity of the independently controlled set of inverters each with their own separate network connection may be a more appropriate way to define FacilityMW for the Collgar Wind Farm.

Currently, all separately dispatchable units with their own network connection point, are classified as a single Facility. However, participants can apply to AEMO to have their multiple dispatchable units registered as an Aggregated Facility. An Aggregated Facility can comprise of separate dispatchable unis with separate network connections connected to the same transmission zone substation (regarded as having the same Electrical Location). In this case, the participant may want to participate in various markets (i.e., STEM, Balancing Market etc.) based on the Aggregated FacilityMW. This can be problematic for the procurement and cost recovery of Contingency Reserve Raise service.

For example, if the Bluewaters Power Station wanted to be classified as an Aggregated Facility, then Contingency Reserve Raise services may have to increase to 434MW when this plant is operating at maximum FacilityMW. However, the maximum credible risk for the electricity system remains at 217MW if the generation units are separately controlled and have separate network connections. Hence, permitting a party to aggregate a facility may result in the over-procurement of Contingency Reserve Raise services and higher costs to the market than are necessary. Typically, Contingency Reserve Raise requirements are 200-250 MW, so permitting Market Participants to aggregate facilities and, as a result, increasing Contingency Reserve Raise services to 417 MW, in this example, would be a significant increase in requirements.

Under the current WEM Rules, AEMO cannot approve an aggregation:

- that would result in the over-procurement of Contingency Reserve Raise services; or
- where the Aggregated Facility would provide ESS, and the ESS capability cannot be accurately depicted for the Aggregated Facility in its entirety.

It should be noted that the Facility capable of providing ESS must offer its ESS quantity at its connection points for the whole Facility, not at the Facility's sub-component level.

For the purposes of the runway method, the maximum FacilityMW that is used to determine a Facility's Risk Value should be based only on the maximum capacity of the largest dispatchable unit with a separate network connection point – this is the credible risk to the power system:

- for a single Facility with a single dispatchable generation unit, the maximum FacilityMW of the Facility should be equal to the maximum capacity of the single dispatchable generation unit;
- for a single Facility with multiple dispatchable generation units with separate network connections, each unit should be treated separately in the runway method with its maximum

FacilityMW (e.g. the Collgar Wind Farm should be treated as two 109 MW units under the runway method rather than a single unit); and

- in the case of Aggregated Facilities (two or more dispatchable generation units with separate network connections), the FacilityMW should be defined for separate dispatchable generation units.

Conceptual Design Proposal 3:

Application of the runway method should be adjusted to cater for situations where a Facility has multiple dispatchable units with separate network connections. In this situation, each separate dispatchable unit should be treated separately in the runway method (i.e., they should have separate FacilityMW for the purposes of Contingency Reserve Raises cost recovery).

Consultation Question 3:

Do stakeholders support treating separately the units in a Facility for the purpose of calculating the Facility's Contingency Reserve Raise costs, where the units are separately dispatchable and have separate network connections?

7. Contingency Reserve Lower

7.1 Current Cost Recovery Approach

Contingency Reserve Lower is required to cover the risk of a material increase in system frequency due to a loss of a single large load, or multiple loads as a result of the loss of a single network element.

Contingency Reserve Lower costs are currently proposed to be recovered from Loads based on their share of consumption in a trading interval, consistent with the current allocation method for LRR costs.

From 1 October 2023 to 30 September 2025, Contingency Reserve Lower costs will be allocated on a 30-minute basis, based on the load's 30-minute metered consumption quantity.

It is proposed that 5 minute market settlement will be introduced on 1 October 2025. Cost allocation on a five-minute basis is relatively more difficult to implement due to the absence of five-minute metering for loads and a method would need to be developed to profile 30-minute consumption quantities, using SCADA data (where available), to five-minute values. This may involve complex implementation, and SCADA equipment may not be available at all load sites, so costs will be allocated to loads on a 30-minute basis until five-minute metering and five-minute settlement is implemented.

7.2 Contingency Reserve Lower Service Requirements

The requirement for Contingency Reserve Lower is based on the loss of a significant load (i.e., industrial customer) or a network asset that has a number of loads connected to it. The largest credible load rejection event is approximately 120MW[26] and is typically the loss of a transmission line. This may be a radial line feeding the Eastern Goldfields region under specific conditions, or a single line supplying a particular customer.

Currently, the Contingency Reserve Lower service for 2021/22 remains at up to a maximum of 90 MW, which is 120 MW (the largest contingency event) minus 30MW for Load Relief.[27]

LRR is currently provided by generation Facilities in the Balancing Portfolio (by Synergy) that are capable of doing so. These generators are not specifically enabled to provide LRR because it is a by-product of being online and operating.

The potential introduction of a battery that is around 250 MW (with a single network connection) would effectively more than double the largest load in the SWIS. If a large 250 MW battery is brought into the SWIS, then Contingency Reserve Lower services would be increased from 90 MW to 220 MW (i.e., 250MW less 30MW Load Relief).

26 This is based on loss of the Eastern Goldfields region or the Boddington Gold Mine, which are connected to the SWIS by a single transmission line.

27 Load Relief is an assumed change in load that occurs when power system frequency changes. Load Relief relates to how particular types of load (particularly traditional motors, pumps, and fans) draw less power when frequency is low, and more power when frequency is high. When the frequency is high due to the loss of a major load or network element in the WEM, it is assumed that loads will draw 30 MW of additional capacity from the grid.

7.3 Cost Recovery Scenarios with BESS entry in the SWIS

7.3.1 Load Cost Allocation with Runway Method

This section considers whether the current cost recovery approach would be cost-reflective with the entry of large new loads (e.g., a major industrial customer or BESS) and what alternative approach could be considered for the recovery of Contingency Reserve Lower costs.

Assume that a 250 MW BESS enters the SWIS, which increases the Contingency Reserve Lower service requirement to 220 MW. Based on the current LRR price of $3.61/MW per trading interval, the cost for the service would be $795 per trading interval, with the majority of the costs allocated to small loads (loads less than 120MW). Table 6 shows a hypothetical example of the allocation of Contingency Reserve Lower costs using the current cost allocation method (pro-rata) for three loads.

Table 6: Example of Current Cost Recovery Method for Contingency Reserve Lower Costs

Load Description	Aggregate Capacity	Interval Cost[28]	Allocation
BESS (Load A)	250 MW	$91.58	11.5%
Large Load (Load B)	120 MW	$43.96	5.5%
Small Loads (Load C)[29]	1,800 MW	$659.37	82.9%
Total	2,170 MW	$794.91	100.0%

Source: Marsden Jacob 2022

When the BESS (Load A) is not operating, the Contingency Reserve Lower requirement is only 90 MW, which would have a cost of $325 per interval, so the recharging by the BESS (Load A) causes an increase in:

- Contingency Reserve Lower requirements to 220 MW; and
- interval costs to $795.

The Large Load (Load B) and Small Loads (Load C) pay for 88.4% of the Contingency Reserve Lower costs, even though the 250% increase in Contingency Reserve Lower costs is caused by the recharging of the BESS (Load A).

Given that the BESS is responsible for the higher Contingency Reserve Lower requirements and costs, a cost-reflective allocation of the Contingency Reserve Lower costs would be for the BESS (Load A) to cover all or most of the incremental costs associated with the new requirement that it created.

28 Interval cost is based on $3.61 per MW multiplied by the Aggregate Capacity of the Load.

29 Many small loads make up 1,800 MW in aggregate. Individual facility size is less than 120 MW.

A fairer allocation of costs could be achieved by using a modified runway method, as follows:

- apply a runway method to allocate Contingency Reserve Lower costs to Loads, treating all Loads with capacity less than or equal to 120 MW as if they were a single load, consuming 120 MWh; and
- apply the existing method to allocate Contingency Reserve Lower costs (pro-rata based on energy) to Loads with capacity less than or equal to 120 MW.

The proposal is to apply a modified runway method only to loads in excess of 120 MW because the current requirement for Load Rejection Reserve is based on this (i.e., largest current load in the SWIS minus 30 MW for Load Relief). Applying a runway method to loads smaller than 120 MW would require applying it to potentially thousands of loads, and interval meter data is likely to only be available for larger loads. Costs for LRR are currently very modest (only 3% of ancillary service costs) and the focus should be on limiting the increase in the Contingency Reserve Lower costs if large-scale loads (such as BESS) are planning to enter the SWIS.

Table 7 illustrates this modified runway method, using the hypothetical example from Table 6, in comparison to the current method.

Table 7: Modified Runway Method for Allocating Contingency Reserve Lower Costs – Single Battery Case

Load Description	Individual Load Size	Aggregate Capacity	Modified Runway Method			Current Method
			Top Tranche	Small Load Tranche	Total Share	
BESS (Load A)	250 MW	250 MW	52.0%	2.8%	54.8%	11.5%
Large Load (Load B)	120 MW	120 MW	0%	2.8%	2.8%	5.5%
Small Loads (Load C)	<120 MW	1,800 MW	0%	42.4%	42.4%	82.9%
Total		2,170 MW	52.0%	48.0%	100.0%	100.0%

Source: Marsden Jacob 2022

This modified runway method results in cost shares that are more consistent with the causer-pays principle, whereby the facility that causes the higher Contingency Reserve Lower service, the BESS (Load A), covers the extra costs that it causes (i.e., the costs associated with the increase in the Contingency Reserve Lower requirement from 90 MW to 220 MW).

Table 8 presents another hypothetical example, with two BESS entering the market – a large 250 MW unit and smaller 150 MW unit and provides a comparison with the current method.

Table 8: Modified Runway Method for Allocating Contingency Reserve Lower Costs – Two Battery Case

Load Description	Individual Load Size	Aggregate Capacity	Allocation Share				Current Method
			First Tranche	Second Tranche	Small Load Tranche	Total	
BESS (Load A)	250 MW	250 MW	40.0%	6.0%	2.7%	48.7%	10.8%
BESS (Load B)	150 MW	150 MW	0.0%	6.0%	2.7%	8.7%	6.5%
Large Load (Load C)	120 MW	120 MW	0.0%	0.0%	2.7%	2.7%	5.2%
Small Loads (Load D)	<120 MW	1,800 MW	0.0%	0.0%	40.0%	40.0%	77.6%
Total		2,320 MW	40.0%	12.0%	48.0%	100.0%	100.0%

Source: Marsden Jacob 2022

Table 7 and Table 8 show that adopting a modified runway method for the recovery of Contingency Reserve Raise costs would:

- ensure that new large loads exceeding 120 MW would pay for the higher Contingency Reserve Lower requirement that they cause when operating; and
- provides BESS developers with an incentive to reduce the size of their largest dispatchable unit to reduce their liability for Contingency Reserve Lower costs, which would be a more efficient outcome.

7.3.2 Adjusting Load Cost Allocation with Runway Method for Network Contingencies

Loss of a network component can cause the loss of a large industrial customer or BESS and other loads on the network, so consideration needs to be given to network outages in the allocation Contingency Reserve Lower costs.

As a comparison, there are two components to the runway method used for Contingency Reserve Raise:

- Facilities are allocated Contingency Reserve Raise costs using a runway method; and
- Facilities that are on a network that has a Largest Network Risk are allocated Contingency Reserve Raise costs using a separate runway method.

In effect, a Facility or Facilities that are located in a part of the SWIS that has Largest Network Risk will pay for both components.

It could be argued that the increased requirement for Contingency Reserve Raise due to network outages should be attributable to the network operator (Western Power) and not generators. However, the Energy Transformation Taskforce determined that Western Power does not make decisions on where generators wish to connect on their network and hence the network component of Contingency Reserve Raise should be borne by generators.[30]

[30] Energy Transformation Taskforce, Market Settlement, Implementation of five-minute settlement, uplift payments and Essential System Services settlement, 1 December 2019, p.15.

Based on the Energy Transformation Taskforce's decision, loads should also be allocated Contingency Reserve Lower costs for the network risk. The proposal is to:

- allocate Contingency Reserve Lower costs to Loads, as indicated in section 7.3.1; and
- allocate Contingency Reserve Lower costs caused by network contingencies using a separate runway method that applies only to relevant loads above the 120 MW limit.

Consider a hypothetical example:

- for a network component on which the average load is 120 MW (an aggregation of smaller loads with all individual facility sizes less than 120 MW),[31] the Contingency Reserve Lower requirement is 90MW (120 MW less 30 MW for Load Relief), and under the runway method proposed in Section 7.3.1, all existing loads would be allocated Contingency Reserve Lower costs (pro-rata);
- the Largest Network Risk on the network is a single 220 kV line and the average load on the line is 120 MW, with peak demand of up to 190 MW;
- the 220 kV line carry can carry around 300 MW, which implies that a 180 MW BESS could locate on the line and draw a maximum of 180 MW, since local load requirements in the region are 120 MW on average;
- if a 180 MW BESS locates on the 220 kV line:
    - the total Contingency Reserve Lower requirement is 270 MW (the 300 MW contingency for the 220 kV line less 30 MW Load Relief); and
    - the Contingency Reserve Lower requirement for the Loads would be 150 MW (the 180 MW contingency for the BESS less 30 MW for Load Relief); and
    - the Contingency Reserve Lower requirement for network risk due to the BESS locating on the 220 kV line is 120 MW (270 MW less 150 MW).

Table 9 presents the proposed Contingency Reserve Lower cost allocations for this hypothetical example method compared to the current cost allocation method.

[31] The average load on the network component is set at 120 MW, which coincides with the Eastern Goldfields average load. Currently, the LRR service is based on the loss of the 220 kV line supplying the Eastern Goldfields (network risk) or the loss of the largest single load (facility risk) in the SWIS (Boddington Goldmine). The highest network risk in the SWIS is consistent with current LRR service requirements.

Table 9: Modified Runway Method for Allocating Contingency Reserve Costs – Single Battery Case with Highest Network Risk

Load Description	Individual Facility Load Size	Aggregate Capacity	Modified Runway Method[32]			Current Method Cost Recovery
			Top Tranche	Small Load Tranche	Total Share	
Cost Allocation to loads that caused the LRR to be 150 MW						
BESS (Load A)	180 MW	180 MW	33.3%	3.9%	37.3%	
Large Load (Load B)	120 MW	120 MW	0.0%	3.9%	3.9%	
Small Loads (Load C)	<120 MW	1,800 MW	0.0%	58.8%	58.8%	
Total		2,095 MW	33.3%	66.7%	100.0%	
Cost allocation to loads that located on a transmission system with Highest Network Risk and caused the LRR to increase to 270 MW (120 MW increase)						
BESS (Load A)			100.0%	0.0%	100.0%	
Large Load (Load B)			0.0%	0.0%	0.0%	
Small Loads (Load C)			0.0%	0.0%	0.0%	
Total			0.0%	0.0%	0.0%	
Total Allocation (270 MW)						
BESS (Load A)					65.1%	8.6%
Large Load (Load B)					2.2%	5.7%
Small Loads (Load C)					32.7%	85.7%
Total					100.0%	100.0%

Source: Marsden Jacob 2022

In summary:

- if the 180 MW BESS (Load A) chooses to locate on the 220 kV line and thereby create a Largest Network Risk, it will be allocated 65.1% of the total Contingency Reserve Lower requirement (270 MW), the Large Load (Load B) would be allocated 2.2% and the Small Loads (Load C) would be allocated 32.7%; and
- if the 180 MW BESS (Load A) chooses to locate in a low network risk region, then it would only be allocated 37.3% of the lower Facility Contingency Reserve Lower requirement (150 MW), the Large Load (Load B) would be allocated 3.9% and the Small Loads (Load C) would be allocated 58.8%.

32 Cost shares may not add up to 100% due to rounding.

7.3.3 Recommendation for Cost Allocation for Contingency Reserve Lower Service Requirements

Conceptual Design Proposal 4:

Apply a modified runway method to allocate Contingency Reserve Lower costs.

If a Network Contingency sets the Contingency Reserve Lower requirement in a trading interval, the costs of procuring contingency reserves are proposed to be split into two components (Load Contingency Reserve Lower and Network Contingency Reserve Lower) and costs are proposed to be allocated as follows:

(1) Load Contingency Reserve Lower cost allocation:

- apply a runway method to allocate the individual load component of Contingency Reserve Lower costs, treating all loads with capacity less than or equal to 120 MW as if they were a single 120 MW load; and
- apply the existing allocation method to allocate load Contingency Reserve Lower costs (pro-rata based on energy consumption) to loads with capacity less than or equal to 120 MW.

(2) Network Contingency Reserve Lower cost allocation as follows:

- apply a runway method to allocate the network component of Contingency Reserve Lower costs to loads in excess of 120 MW (if there is only one large load in excess of 120 MW, that load sets the Network Contingency and will bear 100% of Network Contingency Reserve Lower costs).

If a Load Contingency sets the Contingency Reserve Requirement in a trading interval, only the Load Contingency Reserve Lower cost allocation (1) process will be used.

Consultation Question 4:

Do stakeholders support the proposal to allocate Contingency Reserve Lower costs to loads using the proposed modified runway method?

8. Other Essential System Services

8.1 RoCoF

RoCoF Control is a new service that is required because of the loss of synchronous generation on the power system over time. The intent is that the RoCoF Control services will encourage generators and network operators to improve their ride-through capability, thereby reducing their exposure to the costs of the RoCoF Control service. Large industrial and commercial loads could also potentially benefit from improved ride-through capability.

While generators, network facilities and large-customers are not the causers of low inertia, they will benefit from improved ride-through capability and, if they do so, then smaller loads (i.e., residential and small and medium businesses) may ultimately become the only remaining reason for the RoCoF Control service. Given that smaller loads will ultimately be the beneficiary of the service, it could be argued that they should bear some of the cost of the service.

Under the Amending Rules that will commence at the start of the new market, generators, loads and Western Power will each bear an equal share of the burden of RoCoF Control fees (1/3 each). This cost allocation method is consistent with the causer-pays and beneficiary-pays principles but could be improved if charges were more closely related to the benefits that each participant type would receive by improving their ride-through capability.

The method for RoCoF cost recovery method is out of scope for this review.

8.2 System Restart

System Restart services are required to restore electricity supplies after multiple cascading failures in the electricity system. The pricing of System Restart service is primarily about cost recovery and is not directed at market efficiency. Therefore, the cost of System Restart services should be borne by loads, as there are no efficiency benefits from allocating System Restart service costs to generators or network service providers.

Conceptual Design Proposal 5:

System Restart pricing is primarily focused on achieving cost recovery from beneficiaries, so the cost for System Restart services should be borne by loads, as per the current practice.

Consultation Question 5:

Do stakeholders support retaining the current System Restart cost allocation method?

8.3 NCESS

Non-Co-Optimised ESS (**NCESS**) are either locational services used to substitute for network upgrades or services procured by AEMO.

Where Western Power procures the NCESS, these services are a substitute for network investments, so it is appropriate for Western Power to recover these costs via network access charges

It is difficult, at this early stage, to attribute NCESS costs for services procured by AEMO to individual loads and/or generators and to provide a price signal for customers and/or generators to reduce the requirement for this type of NCESS. As a result, the current objective of NCESS pricing is cost recovery it is appropriate to recover the cost of the NCESS from loads (i.e., there are no obvious efficiency benefits with allocating this cost to generators or network service providers).

Conceptual Design Proposal 6:

Recovery of NCESS should occur as follows:

- where AEMO procures the NCESS, the NCESS costs should be allocated to beneficiaries of the services (Market Customers), given that the current focus of NCESS charges is cost recovery and not market efficiency; and
- where Western Power procures the NCESS, these services are a substitute for network investments, so it is appropriate for Western Power to recover these costs via network access charges.

Consultation Question 6:

Do stakeholders support retaining the current NCESS cost allocation method and to review this once a number of NCESS has been procured?

Energy Policy WA
Level 1, 66 St Georges Terrace, Perth WA 6000
Locked Bag 100, East Perth WA 6892
Telephone: 08 6551 4600
www.energy.wa.gov.au

We're working for Western Australia.

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

Agenda Item 7(a): Overview of Rule Change Proposals (as of 6 December 2022)

Market Advisory Committee (**MAC**) Meeting 2022_12_13

- 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 B will commence on 01/03/2023
2021/212	17/12/2021	Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021	• 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.

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

Agenda Item 8: Review of the Supplementary Reserve Capacity Provisions

Market Advisory Committee (**MAC**) Meeting 2022_12_13

1. Purpose

- To inform the MAC that the Coordinator of Energy (Coordinator's) will commence a review of the Supplementary Reserve Capacity (SRC) provisions in 2023 in accordance with the WEM Rules.

2. Recommendation

The MAC is to note:

- that the SRC Review will be undertaken in 2023 and occur in two stages; and
- the scope of work for the Coordinator's SRC Review (Attachment 1).

Process

- On 23 September 2022, AEMO commenced the SRC process under section 4.24 of the WEM Rules by publishing an invitation for tenders from potential suppliers of supplementary capacity, i.e. "Eligible Services" capable of generation or load reduction[1].
- AEMO provided the following information in its invitation:
  - AEMO is looking to secure 174 MW of Eligible Services for the period between 1 December 2022 and 1 April 2023.
  - The shortfall is due to the early retirement of the Kwinana Cogeneration Plant, an extended Forced Outage of Pinjar unit 10 and increases in AEMO's peak demand forecasts, ongoing fuel supply limitations and project delays.
- Under clause 4.24.19 in the WEM Rules:
  - following each call for tenders for supplementary capacity, the Coordinator must review the Supplementary Reserve Capacity provisions in section 4.24 of the WEM Rules with regard to the Wholesale Market Objectives; and
  - must undertake a public consultation process in respect of the outcome of the review.
- The next Capacity Year for which AEMO may undertake the SRC process is the 2023/24 Capacity Year, commencing on 1 October 2023.
- Under clause 4.24.1 of the WEM Rules, AEMO may commence the SRC process no earlier than six months before the start of a Capacity Year. Therefore, the earliest time

[1] Eligible Services include:
- load reduction excluding Registered Facilities, and Demand Side Programme customers who have not satisfied its Reserve Capacity Obligation for the current cycle;
- generation by facilities not currently registered; and
- generation by Registered Facilities given they don't hold Capacity Credits for the electricity to be provided as SRC and they hold Capacity Credits in a subsequent cycle.

another SRC process could commence is 1 April 2023, which is immediately after the end of the 2022/23 SRC contract period.

- The Coordinator will undertake the SRC Review in two stages, as outlined below and detailed in the scope of work (Attachment 1).

  Stage 1 (commencing in January 2023): Assessment of the AEMO tender process from identification of the capacity shortfall to contract commencement on 1 December 2022.

  Stage 2 (commencing after the end of the SRC contract period on 1 April 2023): Assessment of the performance, overall value and funding of the contracted services.

- At the 11 October 2022 MAC meeting, Mr Geoff Gaston raised concerns that the total cost for the SRC, which could be around $180 million, will have to be borne by consumers. An action item was recorded for EPWA to meet with Mr Gaston to discuss his concerns.
- On 8 November 2022, EPWA met with Mr Gaston. He considered that Capacity Cost Refunds should be distributed to customers and not generators, especially if AEMO had to procure SRC as a result of non-performance of capacity providers.
- The assessment of the funding of the SRC will be part of stage 2 of the SRC Review, as detailed in the proposed scope of work, and the distribution of the capacity refunds will be considered as part of stage two of the RCM Review, which is progressing in parallel.

3. Attachments

(1) Supplementary Reserve Capacity Review – Scope of work

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

Scope of Work for the Review of Supplementary Reserve Capacity Provisions

1. Introduction

The Coordinator of Energy (**Coordinator**) plans to review the supplementary reserve capacity (**SRC**) provisions of section 4.24 of the Wholesale Electricity Market (**WEM**) Rules.

Clause 4.24.19 of the WEM Rules requires that after each call for tenders for supplementary capacity or otherwise acquiring Eligible Services, the Coordinator must:

- review the SRC provisions with regard to the Wholesale Market Objectives; and
- undertake a public consultation process in respect of the outcome of the review.

1.1 Background

1.1.1 2022 Call for Supplementary Reserve Capacity

On 23 September 2022, AEMO commenced the SRC process under section 4.24 of the WEM Rules and published an invitation for tenders from "Eligible Services" capable of generation or load reduction[1].

In its invitation AEMO provided the following information:

- AEMO is looking to secure 174 MW of Eligible Services for the period between 1 December 2022 and 1 April 2023.
- This shortfall is due to the early retirement of the Kwinana Cogeneration Plant, an extended Forced Outage of Pinjar unit 10 and increases in AEMO's peak demand forecasts, ongoing fuel supply limitations and project delays.
- AEMO is progressing the SRC process through an Invitation to Tender within the following timeline:
  - 23 September 2022 - Invitation to Tender opening date;
  - 14 October 2022 - Deadline for questions from Recipients;
  - 19 October 2022 - Deadline for AEMO to answer Recipients' questions;
  - 21 October 2022 - Invitation to Tender closing date;
  - Week commencing 28 November 2022 - Successful Recipients notified of award of Supplementary Capacity Contract; and
  - 1 December 2022 - Anticipated Supplementary Contract start date.

---

[1] Eligible Services include:

- load reduction excluding Registered Facilities, and Demand Side Programme customers who have not satisfied its Reserve Capacity Obligation for the current cycle;
- generation by facilities not currently registered; and
- generation by Registered Facilities given they don't hold Capacity Credits for the electricity to be provided as SRC and they hold Capacity Credits in a subsequent cycle.

1.2 Related Reviews

The Coordinator is currently undertaking a review of the RCM that could affect this review. The Coordinator will ensure any findings from the RCM Review will be accounted for in the SRC Review and vice versa.

2. Project Scope

The objective of this review is to, on the basis of the experience and understanding gained through the current SRS process:

- identify any shortcomings of the SRC provisions;
- identify required improvements to the SRC provisions.

2.1 Guiding Principles

The guiding principles for the review of the SRC provisions are that any proposed revisions to those provisions should:

(1) Enable AEMO to effectively procure required services to ensure system reliability.

(2) Not incentivise strategic withholding of capacity from the Reserve Capacity Mechanism.

(3) Lead to a cost-effective, timely, transparent and flexible process.

(4) Allocate risks to those who can manage them best.

2.2 Project Stages

The intended contract period for the 2022 SRC is 1 December 2022 to 31 March 2023.

The next Capacity Year for which AEMO may undertake the SRC process is the 2023/24 Capacity Year.

Under clause 4.24.1 of the WEM Rules, AEMO may commence the SRC process no earlier than six months before the start of the relevant Capacity Year. Therefore, the earliest time another SRC process could commence is 1 April 2023 which is immediately after the end of the 2022 SRC contract period.

To allow for any changes from the SRC Review to be implemented in time for a SRC process in 2023, should one be required, the Coordinator will undertake the SRC Review in 2 stages.

Stage 1: Review of the SRC provisions related to the procurement of the SRC (the process from 1 September to 1 December 2022)

Stage 2: Review of the operation of the procured SRC services (from 1 December 2022 to 1 April 2023)

Each stage includes:

- assessment of the relevant clauses of the WEM Rules;
- assessment of the actual outcome of the relevant process steps;
- interviews with relevant stakeholders including AEMO;
- consultation paper including any draft Amending Rules; and
- Final Amending Rules, if applicable.

Stage 1: Assessment of the procurement process from identification of the shortfall to contract commencement which would aim to answer the following questions (at minimum):

- Procurement Process:
  - What went well and what did not?
  - Was the invitation to tender document sufficiently clear?
  - Was there sufficient time for AEMO and providers of Eligible Services to effectively participate in and complete the procurement process?
  - Were there any barriers or limitations in the process that may have prevented a better (e.g. price or service specification) outcome?
- Review of the offers received and contracts procured:
  - Is the definition of Eligible Services appropriate?
  - Were any offers received that were not for Eligible Services?
  - Were any capacity providers excluded that should not have been excluded?
  - Is the information described in clause 4.24.8 sufficient to effectively assess offers and contract costs?
  - Are the decision criteria in clause 4.24.8 of the WEM Rules appropriate?
  - Was any actual withholding, or incentive for withholding, of capacity in the RCM identified though the process?
  - Did the offers received meet the service requirements?
  - Were any of the offers rejected and on what basis?
  - Were the offered prices competitive?
  - Was the needed amount of SRC procured and if not, why not?

Stage 2: Assessment of the performance and overall value of the contracted services from contract start to contract end including the following questions:

  - How often and how much of the contracted services were used and in what circumstances?
  - Were some services used in preference to others?
  - Were any issues identified with the actual delivery of the contracted services and what were these issues?
  - Did the overall cost of the services actually result in the lowest cost outcome for consumers?
  - Could any gaming opportunities be identified?
  - Is the current funding regime appropriate, under which the SRC is funded by consumers apart from any amount drawn by AEMO under a Reserve Capacity Security?

Stakeholder Engagement

The SRC Review will include stakeholder consultation through one-to-one meetings with interested parties and parties which were involved in any part of the SRC process. AEMO will be asked to provide all available data relevant to the above questions as well as a qualitative and quantitative assessment relevant to both Stages of the Review.

Energy Policy WA will develop consultation papers, including proposals for any necessary changes, and invite feedback from all stakeholders.

3. Project Schedule

The following is a preliminary high-level project schedule for this.

Tasks/Milestones	Timing
Inform the MAC on the Scope of Work for the SRC Review.	December 2022
Engage a consultant(s) to assist with the review.	January 2023
Stage 1	
Assessment of the process from identifying the shortfall to contracting supplementary capacity	February 2023
Stakeholder interviews	
Consultation paper and TDOWG meeting on any draft Amending Rules	March 2023
Submissions on the consultation paper and any draft Amending Rules	March 2023
Amending Rules for any urgent changes to Minister, if required	April 2023
Step 2	
Assessment of the services from contracting of supplementary capacity to the end of the contracts	April/May 2023
Stakeholder interviews	
Consultation paper including any draft Amending Rules	June 2023
Submissions on the consultation paper and any draft Amending Rules	July 2023
Final Amending Rules, if required	August 2023