# Meeting Agenda

| | |
|---|---|
| **Meeting Title:** | Cost Allocation Review Working Group (**CARWG**) |
| **Meeting Number:** | 2022_08_30 |
| **Date:** | Tuesday 30 August 2022 |
| **Time:** | 12:30 PM to 2:30 PM |
| **Location:** | Online, via TEAMS. |

| Item | Item | Responsibility | Type | Duration |
|---|---|---|---|---|
| **1** | Welcome and Agenda | Chair | Noting | 2 min |
| **2** | Meeting Apologies/Attendance | Chair | Noting | 2 min |
| **3** | Minutes of Meeting 2022_06_07 | Chair | Noting | 2 min |
| **4** | Action Items | Chair | Discussion | 2 min |
| **5** | Assessment of Cost Recovery Options (Step 2 – Practicality Assessment)<br>• allocation of Market Fees<br>• allocation of Frequency Regulation costs<br>• allocation of Contingency Reserve Raise costs | Marsden Jacob | Discussion | 1 hour 45 min |
| **7** | Next Steps | Chair | Noting | 2 min |
| **8** | General Business | Chair | Discussion | 5 min |
| | Next Meeting: 27 September 2022 | | | |

Please note this meeting will be recorded.

Government of **Western Australia**
**Energy Policy WA**

# Minutes

| | |
|---|---|
| **Meeting Title:** | Cost Allocation Review Working Group (**CARWG**) |
| **Date:** | 7 June 2022 |
| **Time:** | 1:00pm – 3:00pm |
| **Location:** | Microsoft TEAMS |

| Attendees | Company | Comment |
|---|---|---|
| Dora Guzeleva | Chair | |
| Oscar Carlberg | Alinta Energy | |
| Tom Frood | Bright Energy | |
| Rebecca White | Collgar Wind Farm | |
| Noel Schubert | Small-Use Consumer Representative | |
| Mark McKinnon | Western Power | |
| Genevieve Teo | Synergy | |
| Paul Arias | Bluewaters Power | |
| Edwin Ong | AEMO | |
| Cameron Parrotte | Woodside | |
| Grant Draper | Marsden Jacob Associates (**MJA**) | |
| Andrew Campbell | MJA | |
| Stephen Eliot | Energy Policy WA (**EPWA**) | |
| Shelley Worthington | EPWA | |

| Apologies | From | Comment |
|---|---|---|
| Jason Froud | Synergy | |
| Hana Ramli | MJA | |

| Item | Subject | Action |
|---|---|---|
| 1 | **Welcome and Agenda**<br>The Chair opened the meeting at 1:00pm.<br>The Chair provided feedback from the MAC meeting on 17 May 2022, noting that the MAC:<br>• reaffirmed the scope of the Cost Allocation Review; | |

| Item | Subject | Action |
|---|---|---|
| | • asked the CARWG to assess the causes and beneficiaries on a more granular level; and<br>• steered the CARWG to focus on the existing product suite. | |
| 2 | **Meeting Apologies/Attendance**<br>The Chair noted the attendance as listed above. | |
| 3 | **Minutes of CARWG Meeting 2022_05_09**<br>Draft minutes of the CARWG meeting held on 9 May 2022 were distributed in the meeting papers on 2 June 2022. The CARWG accepted the minutes as a true and accurate record of the meeting. | |
| | **Action: CARWG Secretariat to publish the minutes of the 5 May 2022 CARWG meeting on the CARWG web page as final.** | **CARWG Secretariat (07/06/2022)** |
| 4 | **Action Items**<br>The paper was taken as read. | |
| 5 | **Jurisdictional Review – Step 1(a)**<br>Mr Draper restated the objectives and guiding principles for the review and noted that the policy assessment will consider the beneficiary-pays principle in addition to the causer-pays principle.<br>Mr Draper noted that the causer-pays and beneficiary-pays principles sometimes align but this is not always the case.<br>Mr Draper outlined the proposed Cost Allocation Hierarchy (Slide 7) and noted that:<br>• costs should first be allocated to causers of the costs because incentivising the causers to minimize the overall cost of delivering a service will create the greatest opportunity for efficiencies;<br>• beneficiaries should be allocated costs where causers cannot be identified or where causers cannot react to the price signal that is provided; and<br>• direct beneficiaries should be allocated costs before indirect beneficiaries.<br>Mr Draper noted that the review will be limited to cost allocation approaches that can be implemented through the WEM Rules and will not consider options like government levies.<br>Mr Draper recapped the jurisdictional review and indicated what services are provided in each jurisdiction, how they are defined, and how costs are recovered in each jurisdiction (slides 10-15). | |

| Item | Subject | Action |
|---|---|---|
| | • Mr Draper noted that MJA did not find an equivalent to Rate of Change of Frequency (**RoCoF**) control services in the other jurisdictions.<br>• Mr Draper provided a qualitative assessment of the adherence of the current methods to allocate Market Fees and Essential System Services (**ESS**) in the Wholesale Electricity Market (**WEM**) to the causer-pays principle (slide 12).<br>o Regarding Contingency Raise services, Mr Arias noted that AEMO procures more spinning reserve amounts due to PV penetration and the flow on effects of inverter failures, and that there was a difference between who is causing the need for these additional reserves and who is paying for them.<br>▪ Mr Draper agreed there was a divergence between the two.<br>▪ Mr Campbell asked about the size of the deviations from the inverter trips.<br>▪ The Chair noted that AEMO procured 70-100 MW of additional spinning reserve on a temporary basis to address tripping of DER caused by disturbances from another contingency event.<br>▪ Mr Carlberg asked whether this is a network design issue rather than the generators on those networks causing the problem.<br>o Mr Draper suggested that the approach to allocate RoCoF services has low adherence to the causer-pays principle because the costs are allocated to those that cannot ride through events, not to those that cause the need for the service.<br>▪ The Chair suggested that the current RoCoF allocation method may not have low adherence to the causer-pays principle in comparison to other services because it allocates costs to loads, network operators and generators, and enables the parties that can demonstrate they can ride through events to avoid paying costs.<br>▪ Mr Draper asked whether loads, network operators and generators were the actual causer.<br>▪ The Chair suggested that that network operators may be a causer of the need for RoCoF services because they can introduce | |

| Item | Subject | Action |
|---|---|---|
| | measures to ride through an event and not cause additional problems, thereby reducing the amount of service that AEMO needs to procure. The Chair noted that all three groups could cause AEMO to procure a particular RoCoF service to ensure system security and that the current approach goes some way to recognize that all three groups contribute.<br>▪ Mr Schubert noted that increasing ride through capability is a solution and suggested that we might be mixing causers and beneficiaries.<br>▪ Ms White noted that EPWA's previous work with Mertz Consulting led to allocating the cost to the three groups on the basis that all three were causers, so it may be worth reviewing the Mertz study.<br>▪ Mr Parrotte noted that inertia is only needed if a generator trips, which is the cause. Inertia could also be required to counter a large load tripping.<br>▪ The Chair noted that there is evidence that the size of what AEMO procures, and the overall cost can be reduced by loads, generation and networks introducing measures to make sure they can ride through events.<br>▪ Mr Parrotte noted that a frequency movement occurs if a large generator or load trips and that inertia can help counter the effects. The amount of the inertia service needed will be reduced if equipment is designed to be able to ride through the event, but inertia is only required due to loss of a big generator or load.<br>▪ Mr Schubert asked whether intermittent generators could be viewed as the cause of the need for inertia because the increase in intermittents is pushing inertia out of the system.<br>o Mr Ong noted that there are methods in the National Energy Market (**NEM**) to allocate System Restart and Network Support Ancillary Services cost to the benefiting region through a Regional Benefit Factor calculation.<br>• The Chair noted the Cost Allocation Review is to focus first on the cost allocations that the Taskforce did not fully consider. | |

| Item | Subject | Action |
|---|---|---|
| 6 | **WEM Alignment with the Causer Pays Principle – Step 1(b)**<br>Mr Draper asked for feedback on nine observations about whether the allocation of costs for Market Fees and each ESS should be aligned with causer- or beneficiary-pays principles.<br>Mr Draper noted that the WEM is at forefront on provision of some of these services because of its high renewable penetration, so MJA was often unable to take learnings from other jurisdictions, in which case MJA reverted to determining the merit of using the causer-pays or beneficiary-pays principle for each service.<br>**Observation 1 – Market Services – allocating costs to Market Customers based on connection costs is consistent with the causer-pays principle** (Slide 19)<br>• Mr Draper noted that AEMO's cost are largely fixed, so Market Fees are not a function MWh, so charging Market Fees on a per MWh basis is not consistent with the causer-pays principle. As a result, the NEM now splits AEMO's costs equally between per MWh and per connection (NMI) charges. However, the NEM did not fully adopt per NMI charges due to equity concerns about the impact of such an approach on smaller retailers.<br>• Mr Draper noted that the UK has moved to charging fees on a gross MWh basis, but that this may not be practical in the WEM because metering is not available to provide the necessary data.<br>• Mr Draper suggested that moving more to a per NMI basis for Market Fees would be closer to the causer-pays principle.<br>• Ms White indicated that she does not think it would be fair or equitable to charge Market Fees on a per NMI basis. Mr Carlberg agreed with Ms White.<br>• Mr Parrotte noted that the Distributed Energy Resources (**DER**) Register could be used to determine gross MWh. The Chair noted that this would be an approximation because gross MWh would also depend on how those installations behave. Mr Carlberg indicated that he did not mind the suggestion of using the DER Register as an approximation.<br>• Mr Schubert commented that a combination of per NMI and MWh Market Fees seems reasonable.<br>• The Chair noted that there is a need to justify all of recommendations in accordance with the guiding | |

| Item | Subject | Action |
|---|---|---|
| | principles, first on the basis of whether the recommended approach reflects the causer-pays principle, and second, whether it sends an effective signal for Market Participants to behave in a certain way.<br>**Observation 2 – Market Services – AEMO's market and system fees are set to recover total budgeted costs of services provided** (Slide 20)<br>• Mr Draper noted that allocation of AEMO's costs is not based on efficient pricing principles (i.e. not based on the marginal cost of supply) because Market Participants cannot react to price signals to consume more or less of AEMO's services. Instead, Market Fees are a cost recovery mechanism, so it makes more sense to pass these costs directly to loads on either a per NMI basis, or on a split between per MWh and per NMI. Mr Draper asked if there is any point of levying Market Fees on generators.<br>• Mr Draper noted that the suggestion is to charge Market Fees to market customers, retailers or aggregators based on the on their number of NMIs or based on a combination of NMIs and grid MWh.<br>• The Chair noted that the ERA sets AMEO's revenue requirement in WA and that generators are better able to participate in the regulatory process, whereas retailers would simply pass these costs on to their customers.<br>• The Chair noted that the suggestion is to simplify Market Fees by only charging them to customers, but then to complicate the fee structure by charging on a per MWh and per NMI basis and asked why there should be a per NMI charge.<br>• Mr Campbell commented that a per NMI charge may fail the fairness test because AEMO's workload increases with the size of the market. Mr Campbell noted there may be a case for using both of these factors because size is important for fairness.<br>• Mr Parrotte noted that some of AEMO's work relates to the number of NMIs but that AEMO does not even know about some of the NMIs.<br>• Mr Campbell noted that he prefers the per MWh approach.<br>• Mr Draper noted Ofgem's argument that, since market participants cannot ration their use of the market operator's services in response to price signals, it is more efficient to charge the costs to beneficiaries, so | |

| Item | Subject | Action |
|---|---|---|
| | the fees should be charged to consumers. How to charge consumers – on a per MWh and/or per NMI basis – is another issue.<br>• The Chair noted the simplest approach would be to maintain the current allocation method because AEMO would not incur costs to change its systems and market participants would not need to change their contracts.<br>• Ms White noted that it is important to think about transitional arrangements – first around equity, and second around the impact of policy changes on PPAs. Mr Arias agreed with Ms White on the importance of considering the contractual arrangements, which can distort how costs are passed to customers.<br>• Mr Arias noted that fees allocated to generators are then passed on through three or four different hands before they reach the final customer, who are the ultimate beneficiaries of the market. Charging these fees to customers on a per MWh basis properly allocates these costs.<br>• Mr Ong asked for a table that outlines the allocation options and the advantages and disadvantages of each option in comparison to the current arrangements. Mr Draper indicated that this would be part of the practicality assessment in the next step of the review.<br>• The Chair noted that generation would need to be curtailed or plant would need to be cycled if DER is not integrated with the WEM and asked who the beneficiary is from such integration. The Chair suggested it is generation and not DER that benefits from the integration.<br>• Mr Campbell noted the benefit from integrating DER into the market is meant to be lower costs and improved security and reliability.<br>• Mr Arias noted that consumers benefit from DER, or they would not invest in PV, and it is this investment that causes costs to the market, so DER should bear burden of these costs.<br>• The Chair agreed that consumers are benefiting from the installing PV, but they are not benefiting from AEMO integrating DER into the market. The Chair noted that DER integration into the market benefits a number of parties because it maintains security of supply and reduces impact on the rest of the market participants. | |

| Item | Subject | Action |
|---|---|---|
| | • Ms White commented that she did not think the issue is opposing the integration of DER into the market, but that DER is a beneficiary because the integration enables its participation in more markets, ~~and everyone should pay for the infrastructure.~~ and hence it ought to be paying for the cost of that integration (e.g. system build).<br>• Mr Carlberg suggested that DER are excluded from the current fees allocation because they avoid the current per MWh charges.<br>• Mr Draper noted that customers with DER reduce their consumption and are therefore charged a lower percentage of AEMO costs than a customer without DER, and that this is the source of the inequity.<br>o This is why the UK is moving to charge market fees based on gross MWh rather than grid MWh.<br>o Mr Draper indicated that a per NMI charge partially addresses this inequity because DER customers would make a larger contribution under such an approach than if fees are only charged on a per MWh basis using grid MWh.<br>o Mr Draper suggested that:<br>▪ the fairest approach would be to allocate Market Fees using a per MWh charge based on gross MWh;<br>▪ the next fairest approach is a combination of a per NMI charge and a per MWh charge based on grid MWh; and<br>▪ the least fair approach is a per MWh charge using grid MWh.<br>• The Chair noted that the NEM is moving to allocate AEMO fees to wholesale market participants. Mr Draper acknowledged this but indicated that there does not appear to be efficiency reasons to do this.<br>• Mr Schubert noted WACOSS' view is that not charging costs to DER will 'socialise' the costs to all customers, which is not fair for vulnerable customers who cannot afford PV.<br>• Mr Parrotte noted that there is an argument that a DER customer using the same kWh as a non-DER customers is causing more costs for AEMO.<br>**Observation 3 – Regulation Service** (Slide 21)<br>• Mr Draper noted that:<br>o as demonstrated by the causer-pays methodology in the NEM, it is possible to measure the | |

| Item | Subject | Action |
|---|---|---|
| | contribution of causers' frequency deviations and to set charges in the WEM to incentivise causers to minimise such deviations; and<br>o the current method to allocate Regulation services in the WEM is based on grid MWhs, which does not provide the correct price signals and may incentivise customers to use energy in a way that imposes more Regulation costs.<br>• Mr Draper indicated that consideration should be given to applying a causer-pays methodology in the WEM. This could be adopting the approach in the NEM or a new approach that AEMO is currently investigating.<br>• Mr Ong provided some commentary:<br>o the NEM methodology is based on dispatch targets in comparison to the four second SCADA data;<br>o the AEMC has recognised that the NEM methodology is backwards looking over a month, so it is considering a new method that could look at generators' inaccuracies at a closer time frame; and<br>o a conceptual 'tolerance' method is being investigated based on the tolerance formula that AEMO distributed to CARWG members, via the CARWG secretariat, by email on 3 June 2022.<br>• The Chair indicated that MJA should develop the options, along with the pros and cons for each option, for consideration by the CARWG before MJA models the options.<br>• Mr Schubert noted the NEM methods seem very complicated.<br>• Mr Frood sought to clarify whether we should use deviation from the ideal or from GPS.<br>o Ms White noted that, given the decision to have a 'grandfathered' GPS framework, the comparison needs to be against the registered GPS, not ideal.<br>**Observation 4 – Contingency Reserve Raise** (Slide 22)<br>• Mr Draper noted that the proposed runway method appears to be a good methodology in terms of allocating costs. Mr Draper asked whether this is to be further considered.<br>• The Chair noted that consideration will need to be given at some point to the equity issues for aggregated sites where, depending on whether they | |

| Item | Subject | Action |
|---|---|---|
| | are connected to the network at one point or more points, they will suffer larger consequence. The Chair asked MJA to only look at isolated issues that have been determined to be a problem.<br>**Observation 5 – Contingency Reserve Lower** (Slide 23)<br>• Mr Draper noted that this service is a function of the size of the load and that a runway allocation method could be developed to apply to loads, analogous to the approach for Contingency Reserve Raise. Mr Draper sought guidance on whether to pursue this option.<br>• Ms White noted that:<br>o one of the benefits of applying the runway method for Contingency Reserve Raise is that it creates a locational signal for generators to avoid creating bigger contingencies, but that there will be less of a locational signal for loads; and<br>o it may be very complex to create a runway method for Contingency Reserve Lower given the number of loads and hence the cost of implementation likely outweighs any benefits.<br>• Mr Campbell noted smelters are the large loads and are really not dispatchable, so it would be sensible to use a simpler approach.<br>• Mr Draper agreed that MJA should focus on a simpler approach.<br>• Mr Parrotte noted the market for Contingency Reserve Lower is about 1/10 of the size of the market for Contingency Reserve Raise.<br>• The Chair noted there are already very strong incentives for loads to avoid tripping.<br>• Mr Carlberg commented that he doubted this service would drive behavioral change.<br>• Ms White questioned if a runway approach would only apply to dispatchable loads.<br>• Mr Schubert noted there more solutions to the problem will become available in future and that batteries could be part of the solution and part of the problem.<br>• Mr Frood noted that a trip could be a grid issue.<br>• The Chair suggested that Contingency Reserve Lower should be a lower priority issue that can be considered later if there is time.<br>**Observation 6 – RoCoF (Inertia)** (Slide 24) | |

| Item | Subject | Action |
|---|---|---|
| | • Mr Draper noted that the current methodology is to allocate 1/3 of costs to each of loads, network operators and generators, and to enable parties that can ride through events to avoid payment of cost, and that this method is consistent with the beneficiary-pays principle.<br>• The Chair suggested RoCoF has been recently addressed by the Taskforce and should be a lower priority.<br>• Mr Carlberg asked how the ride through of loads is assessed and if AEMO can provide a forecast of how often and how much it thinks this RoCoF service is going to be triggered/paid.<br>• The Chair noted AEMO has a procedure for parties to apply to AEMO and for AEMO to assess whether they have ride through capability.<br>• Ms White observed that Western Power and most (if not all) generators will have ride through capability, so loads will be allocated most RoCoF costs in practice.<br>• The Chair noted that the quantum of the service is unknown. The Chair asked AEMO to advise if it can assess how much RoCoF service it will procure at the start of the market, and if so, to provide an assessment.<br>• Ms White noted that the Taskforce's technical study suggested that Contingency Reserve Raise volumes are expected to decrease over time and to be substituted by RoCoF.<br>**Observation 7 – Black Start Services** (Slide 25)<br>• Mr Draper noted that the requirement for black start is not driven by the actions of Market Participants, so allocating black start costs is about recovering costs from beneficiaries. The options are to allocate these costs based on the number of NMIs or based on a combination of NMIs and grid MWh.<br>**Observation 8 – Non-Co-optimized Essential System Services –Voltage Control and Transient and Oscillatory Stability** (Slide 26)<br>• Mr Campbell noted that voltage control tends to be local, and that transient and oscillatory stability are related to transmission and are not caused by loads. The causer-pays principle indicates that these costs should be paid by network operators. | |

| Item | Subject | Action |
|---|---|---|
| | • The Chair noted that these costs are recovered through network charges and Mr Draper agreed that this was the appropriate.<br>**Observation 9 – Non-Co-optimized Essential System Services – Fast Frequency Response** (Slide 27)<br>• Mr Draper noted that the principles that would apply to this service are the same as would apply to Regulation.<br>• Mr Campbell noted that this is going to be an ongoing co-optimised service in the NEM and the Chair noted that it is a transitional service in the WEM that is unlikely to continue.<br>• Mr Draper noted that, if it were an ongoing service in the WEM, it would be appropriate for its costs to be charged in the same way as Regulation.<br>• The Chair noted that how an NCESS service, more generally, should be charged in the future should be discussed as part of the review because it has never previously been discussed, apart from network support services. It would be beneficial to discuss principles for how AEMO might procure and recover these costs for these services.<br>• Ms White noted that these are non-network solutions and that we need to be careful not to create incentives for Western Power to underinvest.<br>• Mr Parrotte noted that Fast Frequency Response sits between inertia and Contingency Raise (it is faster than Contingency Raise but slower than inertia) and suggested looking at the cost recovery of inertia and Contingency Raise as a guide.<br>• The Chair advised not look at the interim service, and instead to think about the longer term Non-Co-optimised ESS and whether we need principles for how these costs are recovered. | |
| | **ACTION: AEMO is to advise whether it can assess how much RoCoF service it will procure at the start of the market, and if so, to provide an assessment.** | **AEMO (22/08/2022)** |
| 7 | **Next Steps**<br>A table will be prepared as part of step 2 of the review with the options for allocating each cost and assessing the pros and cons for each option.<br>Outcomes from 7 June 2022 CAR Meeting will be presented at the MAC meeting on 28 June 2022. | |

| Item | Subject | Action |
|---|---|---|
| | • Any CARWG members that wish to provide additional comments regarding the discussions at the CARWG meeting on 7 June 2022 are to do so by COB Friday 10 June 2022 so that the advice can be provided to the MAC.<br>Mr Draper indicated that the CARWG will move to step 2 of the review (the practicality assessment) at its next meeting, including:<br>• options that can be practically and efficiently applied in the WEM to allocate Market Fees and ESS costs;<br>• assessing each option against the guiding principles; and<br>• modelling the impact of each option. | |
| **8** | **General Business**<br>No general business was discussed.<br>The next CARWG meeting is scheduled for 30 August 2022. | |

**The meeting closed at 2:50pm.**

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

# Agenda Item 4: CARWG Action Items

Cost Allocation Review Working Group (**RCMRWG**) Meeting 2022_08_30

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

| Item | Action | Responsibility | Meeting Arising | Status |
|---|---|---|---|---|
| 1 | CARWG members are to advise EPWA by email of any examples where the Market Fees or ESS cost allocations are not sending the appropriate signals and where the causer pays principle should apply. | CARWG members | 2022_05_09 | **Closed**<br>EPWA received comments from Rebecca White (Collgar) on 27 May 2022 and forwarded these comments to CARWG members on the same day.<br>EPWA has not received any other responses from CARWG members as of 23 August 2022. |
| 3 | CARWG members are to review the tables in slides 18-21 (from CARWG_2022_05_09) and provide comments on whether anything is incorrect or missing. | CARWG members | 2022_05_09 | **Closed**<br>EPWA has not received any responses from CARWG members as of 23 August 2022. |
| 4 | CARWG Secretariat to publish the minutes of the 5 May 2022 CARWG meeting on the CARWG web page as final. | CAR Secretariat | 2022_06_07 | **Closed**<br>The minutes were published on the Coordinator's Website on 7 June 2022. |

| Item | Action | Responsibility | Meeting Arising | Status |
| --- | --- | --- | --- | --- |
| 5 | AEMO is to advise whether it can assess how much RoCoF service it will procure at the start of the market, and if so, to provide an assessment. | AEMO | 2022_06_07 | **Open**<br>AEMO has not yet provided a response on this action item. |

Agenda Item 5

Government of **Western Australia**
**Energy Policy WA**

# Cost Allocation Review

## Assessment of Cost Recovery Options

**30 August 2022**

**Presenter: Grant Draper, Marsden Jacob Associates**

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

# Agenda

# Timeline and Purpose

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

# Recap of Assessment of Cost Recovery Methods

# Guiding Principles

1. Meet the Wholesale Market Objectives (economic efficiency, safe and reliable, technology neutral, encourage competition, minimise long term costs, and encourage energy efficiency)
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
4. Use the causer-pays principle, where practicable and efficient
5. Use the beneficiary-pays principle where appropriate (extended to scope)

# Assessment of Priority – Summary

| Service | Causers | Is Allocation Practice aligned with Guiding Principles? | Consequence of Misalignment | Assessment Priority | Rationale | Next Steps |
|---|---|---|---|---|---|---|
| Market Services | • Market Participants (generators/retailers)<br>• Network Operators<br>• DER / final customers | Partially aligned with causer pays principle | Low impact on market outcomes (economic efficiency and cost burden) | High | Has not been previously Reviewed | Development and assessment of two alternative options against current practice |
| Frequency Regulation | • Scheduled Generators<br>• Semi-Scheduled Generators<br>• Loads (including DER) | Not aligned | Not driving reduction in level and cost of providing regulation services | High | Has not been previously reviewed | Development and assessment of two alternative options against current practice |
| Contingency Reserve Raise | • Scheduled Generators<br>• Semi-Scheduled Generators | Aligned with causer pays principle | Aligned | Medium | Runway method was reviewed by Energy Transformation Taskforce | Refinement of proposed method to address equity issues |
| Contingency Reserve Lower | • Small and Large Loads<br>• Energy Storage (recharge) | Partially aligned with causer pays principle | Not providing incentives for large loads / energy storage to minimise load reduction | Medium | Emerging issue with storage systems entering the SWIS | Modified runway method to be considered (no precedent for this, outcome uncertain) |

# Assessment of Priority – Summary

| Service | Causers | Is Allocation Practice aligned with Guiding Principles? | Consequence of Misalignment | Assessment Priority | Rationale | Next Steps |
|---|---|---|---|---|---|---|
| RoCoF | • Scheduled Generators<br>• Semi-Scheduled Generators<br>• Loads (including DER) | Partial alignment with causer and beneficiary pays principles | Unknown | TBD | Has been reviewed by Energy Transformation Taskforce | Development of new method to split costs between causers and beneficiaries |
| Black Start | • No specific causer | Aligned | Aligned | Low | No major benefit of further assessment | No further assessment required |
| Non-co-optimised ESS | • Network Operator | Aligned | Aligned | Low | No major benefit of further assessment | No further assessment required |
| Fast Frequency Response | • Scheduled Generators<br>• Semi-Scheduled Generators<br>• Loads (including DER) | NA | NA | Low | Temporary service in WEM, review when it becomes a permanent service | No further assessment required |

# Assessment of Allocation of Market Fees

# Market Fees Cost Allocation

**MAC supported:**

- High priority for assessment of alternative methods to allocate Market Fees
- Two options to be developed and compared with the current allocation method in the WEM
  - Current NEM Practice
  - Hybrid Option

# Options for Allocation of Market Fees

**Current WEM Method:**

- Each Market Participant is charged fees based on their Metered Schedule for all their Registered Facilities and Non-Dispatchable Loads for all Trading Intervals for the day

**NEM Method:**

- Split between generators, market customers and TNSPs (based on directly attributable costs, un-attributable costs are allocated to market customers)
- For market generators
  - o 50% charged on capacity (MW)
  - o 50% on grid generation (MWh)
- For market customers:
  - o 50% based on grid demand (MWh)
  - o 50% based on number of connections

**Hybrid Method:**

- 50% split between Market Participants selling and buying WEM services
- For Market Participants selling WEM services
  - o 50% charged on capacity (MW)
  - o 50% on generation output (MWh)
- For Market Participants buying WEM services
  - o 50% based on grid demand (MWh)
  - o 50% based on IRCR (MW)

# AEMO WEM Fees 2022/23

| WEM Fees | Budget | Notes |
|---|---|---|
| Revenue Requirement ($m) | 41.9 | |
| Consumption (GWh) | 17,950 | |
| WEM Market Operator Fee ($/MWh) | 0.4913 | |
| WEM System Management Fee ($/MWh) | 0.6646 | |
| WEM Fee ($/MWh) | 1.1559 | Paid by generators and loads |
| WEM fee benchmark ($/MWh) | 2.3118 | Impact on loads |
| Derived Annual Revenue ($m) | 41.9 | Cost recovery |
| Market Participant Buying WEM Services – Annual Revenue ($m) | 20.95 | 50% |
| Market Participant Selling WEM Services - Annual Revenue ($m) | 20.95 | 50% |

# Cost Recovery by Method

| Allocation of AEMO Market Fees Only - 2022-23 | | | |
|---|---|---|---|
| | Current WEM Fees ($ per annum) | NEM Fee Approach ($ per annum) | Hybrid Method ($ per annum) |
| Cost Allocations by Participant Type | | | |
| Market Participant | 20,950,000 | 16,395,587 | 20,950,149 |
| Market Customers | 20,950,000 | 20,371,780 | 20,950,000 |
| Western Power | 0 | 5,132,750 | 0 |
| Total | 41,900,000 | 41,900,117 | 41,900,149 |
| Cost Allocations to Wholesale Participant [(a)] | | | |
| Synergy | 8,095,450 | 6,713,114 | 8,577,963 |
| Alinta | 3,496,248 | 2,855,362 | 3,648,559 |
| Other | 9,358,303 | 6,827,110 | 8,723,627 |
| Total | 20,950,000 | 16,395,587 | 20,950,149 |
| Cost Allocations to Customer Type | | | |
| Residential (no BTM DER) | 9.40 | 13.40 | 12.92 |
| Residential (3 kW Rooftop PV) | 7.00 | 12.23 | 11.71 |
| Residential (5 kW Rooftop PV) | 3.81 | 10.66 | 10.09 |
| Small Business (no BTM DER) | 25.32 | 21.22 | 32.04 |
| Small Business (10 kW Rooftop PV) | 12.72 | 15.03 | 25.68 |
| Large Commercial (no BTM DER) | 6,160.25 | 3,033.00 | 5,993.00 |
| Large Commercial (250 kW Rooftop PV) | 6,006.90 | 2,957.72 | 5,843.82 |

Note: (a) Based on public SCADA generation data (not loss adjusted)

# Allocation to Market Generators in the WEM

| Participant | Plant_ID | Annual GWh | Maximum Capacity (MW) | Capacity Factor | Current WEM Fee ($ per annum) | NEM Fee / WEM Hybrid Approach ($ per annum) |
|---|---|---|---|---|---|---|
| ALBGRAS | ALBANY_WF1 | 57.5 | 21.6 | 30% | 67,127 | 70,902 |
| ALBGRAS | GRASMERE_WF1 | 43.2 | 13.8 | 36% | 50,462 | 49,122 |
| ALINTA | ALINTA_PNJ_U1 | 667.2 | 143.0 | 53% | 778,728 | 638,140 |
| ALINTA | ALINTA_PNJ_U2 | 545.3 | 143.0 | 44% | 636,422 | 566,315 |
| ALINTA | ALINTA_WGP_GT | 32.8 | 196.0 | 2% | 38,309 | 355,273 |
| ALINTA | ALINTA_WGP_U2 | 26.7 | 196.0 | 2% | 31,134 | 351,651 |
| ALINTA | ALINTA_WWF | 304.6 | 89.1 | 39% | 355,528 | 332,158 |
| ALINTA | BADGINGARRA_WF1 | 582.3 | 130.0 | 51% | 679,673 | 565,862 |
| ALINTA | YANDIN_WF1 | 808.6 | 211.7 | 44% | 943,780 | 839,161 |
| COLLGAR | INVESTEC_COLLGAR_WF1 | 663.2 | 218.5 | 35% | 774,051 | 765,183 |
| MERREDIN | NAMKKN_MERR_SG1 | 0.4 | 92.6 | 0% | 473 | 158,952 |
| MERSOLAR | MERSOLAR_PV1 | 263.6 | 100.0 | 30% | 307,691 | 326,696 |
| MPOWER | AMBRISOLAR_PV1 | 2.1 | 1.0 | 25% | 2,478 | 2,896 |
| MUMBIDA | MWF_MUMBIDA_WF1 | 205.2 | 55.0 | 43% | 239,494 | 215,146 |
| NEWGEN | NEWGEN_KWINANA_CCG1 | 1,886.2 | 335.0 | 64% | 2,201,488 | 1,685,322 |
| NGENEERP | NEWGEN_NEERABUP_GT1 | 226.4 | 342.0 | 8% | 264,217 | 719,533 |
| SYNERGY | MUJA_G5 | 744.3 | 195.8 | 43% | 868,645 | 774,020 |
| SYNERGY | MUJA_G6 | 731.3 | 193.6 | 43% | 853,511 | 762,611 |
| SYNERGY | MUJA_G7 | 1,142.6 | 212.6 | 61% | 1,333,592 | 1,037,485 |
| SYNERGY | MUJA_G8 | 1,232.0 | 212.6 | 66% | 1,437,901 | 1,090,132 |
| SYNERGY | PINJAR_GT1 | 10.6 | 38.5 | 3% | 12,322 | 72,207 |
| SYNERGY | PINJAR_GT10 | 52.0 | 118.2 | 5% | 60,735 | 233,160 |
| SYNERGY | PINJAR_GT11 | 178.2 | 130.0 | 16% | 208,009 | 327,803 |
| SYNERGY | PINJAR_GT2 | 6.0 | 38.5 | 2% | 6,970 | 69,506 |

- Using maximum capacity for 50% of AEMO fee allocation increases cost recovery from generators with low capacity factors
- Baseload generators and high capacity factor wind generators benefit from this change

Note: Based on public SCADA generation data (not loss adjusted) and public Facility data

# Cost Recovery by Method - Retailers

- IRCR and metered scheduled data by electricity retailer is confidential, so can only comment on results by Method
- 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
- Retailers with a higher proportion of business customers will pay less under WEM Hybrid Method because their IRCR is proportionately lower when compared to residential customers

# Overall Impact on Major Market Participants

- Overall, Synergy incurs higher charges by moving to the WEM Hybrid approach mainly due to use of IRCR to allocate market fees to loads and use of Maximum Capacity to allocate market fees to generators (i.e. recover higher fees from low capacity generation)
- Alinta Energy's fee allocation remains similar
- Perth Energy has a reduction due to a decrease in costs allocated to customers on basis of IRCR
- Overall reduction in AEMO fees for most other Market Participants

# Advantages of the Hybrid Method

- Charging generators based on capacity (50%) ensures that low capacity factor generators make an adequate contribution to Market Service costs, no free riding on base-load generators
- AEMO costs not driven by sent out generation, but on basis of number of participants and number of assets
  - New assets, such as OCGT-aero, pumped hydro and BESS all likely to have capacity factors below 20%, but AEMO will spend time and resources on planning, certification, testing and market rule changes to facilitate entry of flexible generation and storage
- Charging Market Customers on basis of IRCR ensures the recovery of costs from retailers that have a higher portfolio of customers with rooftop PV. This reduces the inequity that results in recovering AEMO costs on metered consumption, which customers with rooftop PV can minimise.

**Recommendation:** Adopt the Hybrid Method to allocate Market Fees (AEMO, ERA and EPWA costs)

# Allocation of Frequency Regulation Costs

# Frequency Regulation Cost Allocation

**MAC supported assessing:**

- Current NEM practice (Causer Pays Methodology)
- A new causer pays methodology potentially based on Tolerances

# Methods to Recovery Frequency Regulation Costs

**Current WEM method**

- Costs allocated to Market Participants in proportion to their Regulation Contributing Quantity
- Regulation Contributing Quantity is the absolute value of the sum of:
  - Semi-Scheduled Facilities
  - Non-Scheduled Facilities
  - Non-Dispatchable Loads
- Scheduled Facilities are not allocated costs

**NEM Causer Pays method**

- Measure generator performance using 4 second SCADA data for both Scheduled and Semi-Scheduled Generation
- Split between generation and load is dependent upon NEM demand forecast accuracy and can vary
- Generation cost are split between participants based on raise and lower 'not' enable factors
- Sum of factors is normalised over a 28 day settlement period

**Tolerance Method**

- Provides additional incentives for generators to improve forecasting and control at 4 second intervals
- Better performance of generators reduces generation share of causer pay costs

# Approach to Assessing Allocation Methods

**NEM Causer Pays method**

- Use historic NEM aggregation reports to produced a distribution for each generator (Scheduled and Semi Scheduled) performance of:
    - o Lower – enable factor and not enable factor
    - o Raise – enable factor not enable factor
- Normalise the performance of NEM generators based on Generation/Installed Capacity to produce a probability distribution of performance by fuel type
- For each NEM region produce a similar performance distribution for both:
    - o within 5 minute demand error
    - o forecast demand error
- Demand performance is then normalised by total region demand (GWh) for the matching 28 days
- Using the four distributions calculated above, produce a Monte Carlo model with existing WEM parameters

**Tolerance Methodology**

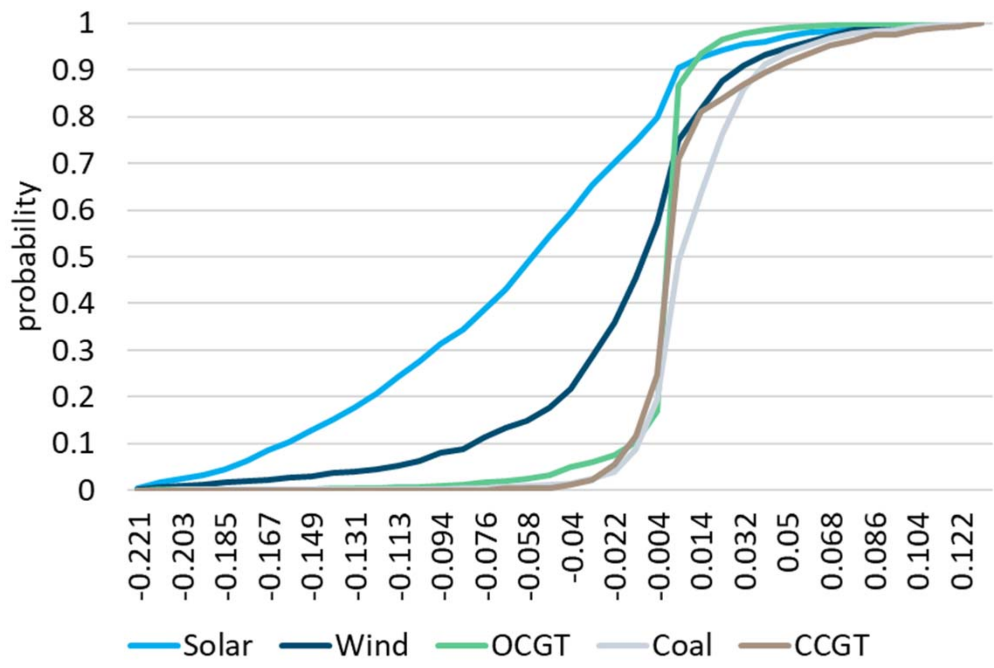
- Analysis of 4 second SCADA data between NEM and WEM
- Use the SCADA analysis to scale the current fuel type distributions in Monte Carlo model and compare improvement in total causer pay factor

# NEM Causer Pays Method

# NEM Causer Pays Results – Lower Not Enable Factor

## Distribution of Lower Not Enable Factor (LNEF) from 21 June 2020 – 22 May 2022

- A wide distribution indicates that there is more variation in Not Enable Factor for each installed MW of capacity
- The higher the negative value the worse the plant performance at meeting the target
- Solar PV was the worst performer with a 50% chance of the LNEF being < -0.06/MW



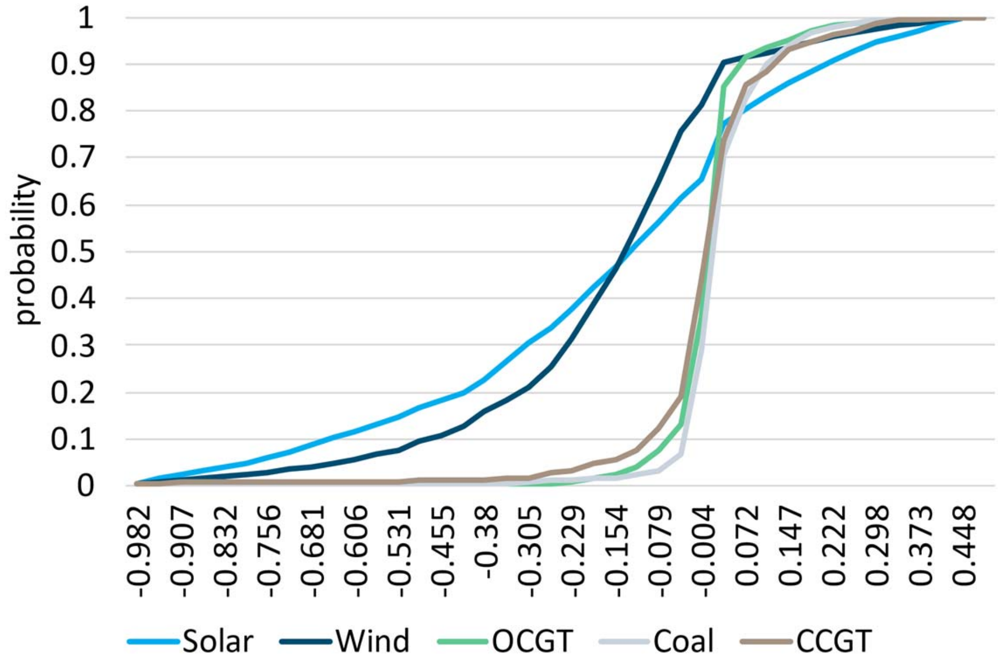



Working together for a **brighter** energy future.

# Causer Pays – Raise Not Enable Factor

## Distribution of Raise Not Enable Factor (RNEF) from 21 June 2020 – 22 May 2022

- The x-axis for RNEF covers a wider range than LNEF (-.982 compared to -.221)
- The wider range indicates that RNEF is a bigger component in deviation from the 5-minute target
- Solar is still the worst performer by technology type
- The median value for wind RNEF distribution is -0.154 compared to -0.012 for LNEF



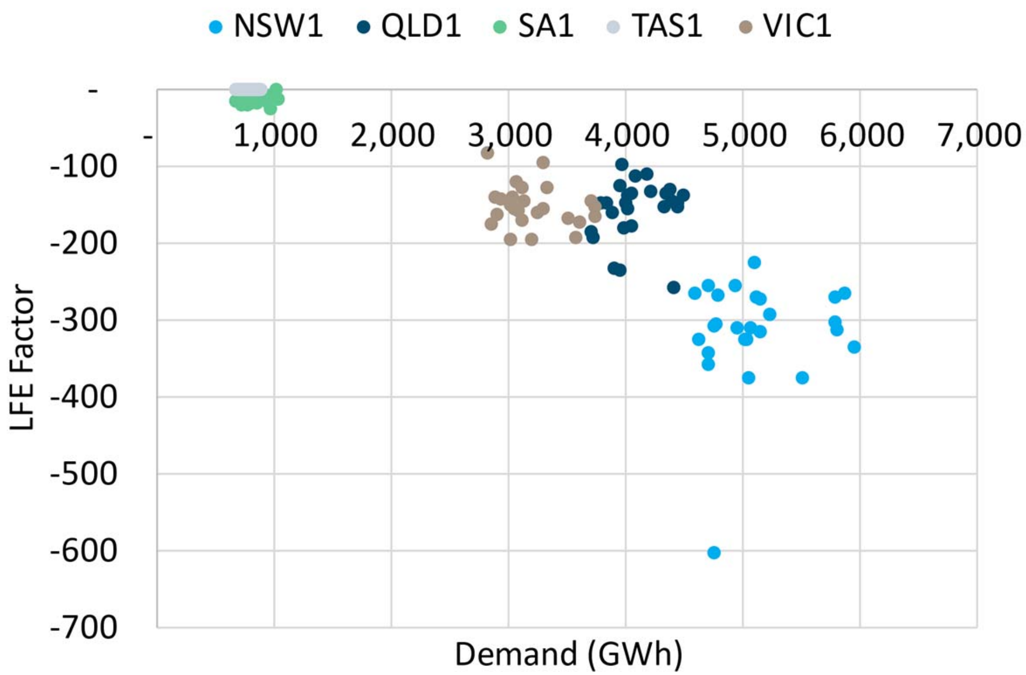



Working together for a **brighter** energy future.

# Causer Pays – Within 5 Minute Error

## Within 5-minute error LFE Factor vs NEM Region Demand (GWh) - 21 June 2020 – 22 May 2022

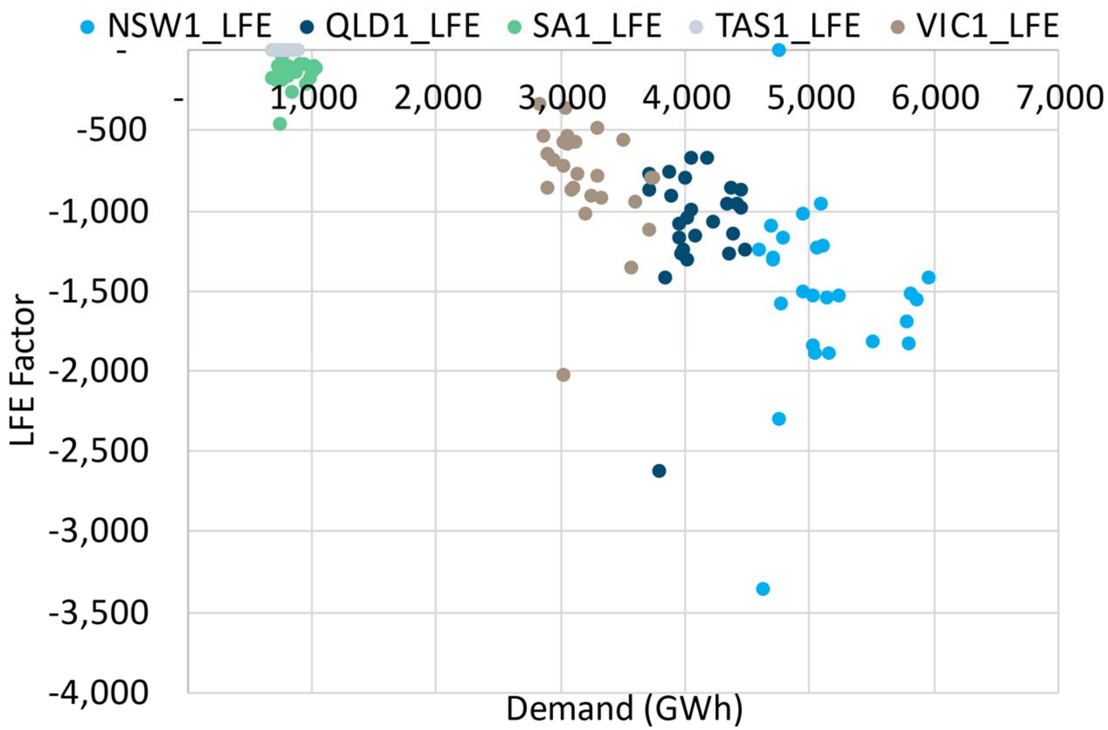
- Tasmania Load Forecasting Error was excluded from the distribution as it has no errors
- There is a general trend of increasing error with increasing region demand, which is expected, as the absolute error value would increase with a similar % error



# Causer Pays – Load Forecast Error

## Load Forecast Error LFE Factor vs NEM Region Demand (GWh) - 21 June 2020 – 22 May 2022

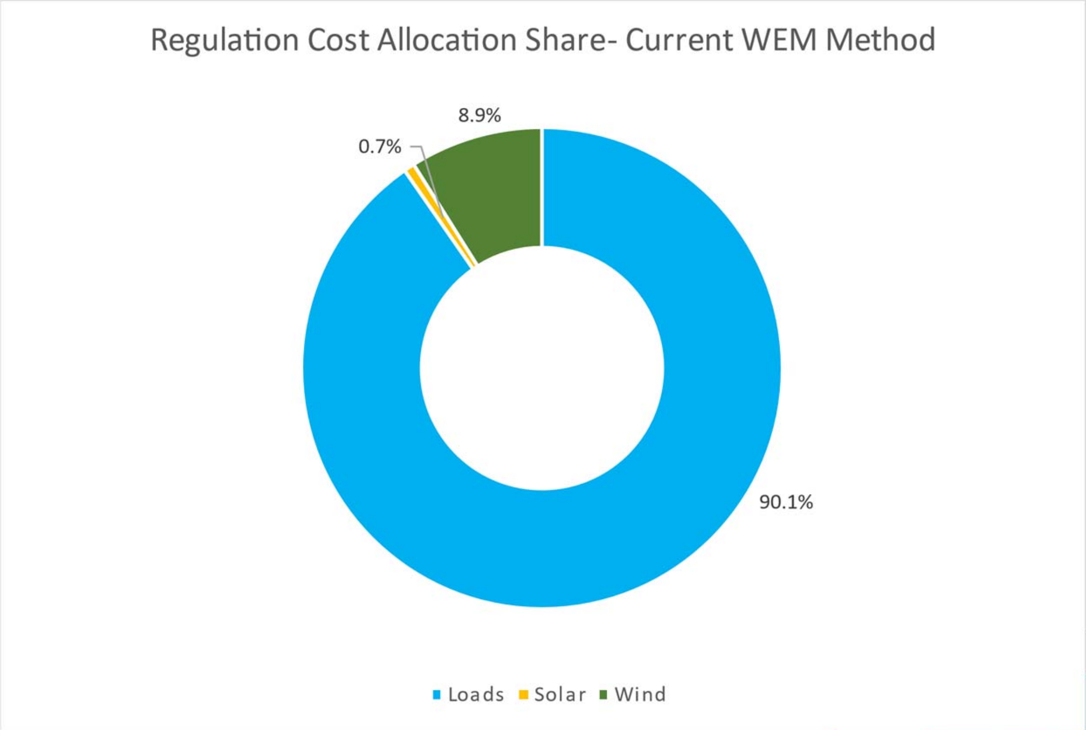
- The Load Forecast Error (LFE) factor was much higher than the within 5-minute error, accounting for around 80% of the total



# Causer Pays – Current WEM methodology

## Frequency Cost Allocation example 27/7/2021 to 28/8/2021

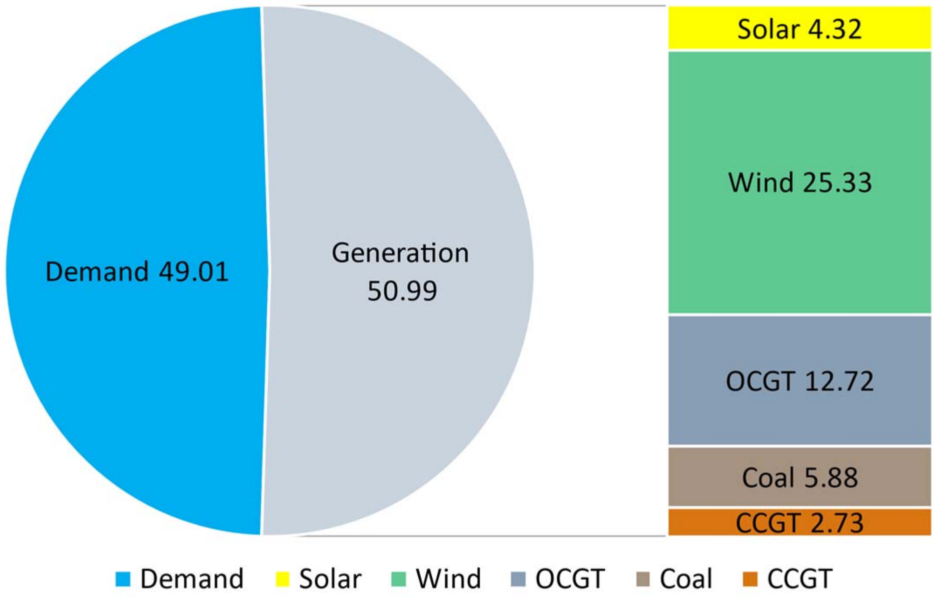
- More than 90% of allocation using the current WEM method goes to Loads



# Causer Pays – WEM Monte Carlo – 100 simulations

## Results of 100 simulations of applying the distributions to WEM generators with Average WEM 28-day load (1376GWh)

- Units were calculated with individual seed numbers
- For the current capacity in the WEM the split is about even between generation and demand
- Wind accounts for the biggest pro-ration of generator costs driven by:
  - o BADGINGARRA_WF1
  - o YANDIN_WF1
  - o WARRADARGE_WF1




Note: numbers are % of total allocated costs for frequency regulation

# Implications of Causer Pays Analysis

- Current WEM methodology over recovers costs from loads and under recovers costs from intermittent generators
  - This is not consistent with causer pays principle, whereby intermittent generators should pay for the additional regulation services costs that they impose
- Adoption of the NEM Causer Pays Methodology would ensure that intermittent generators consider the following to minimise variations between target (or cap) and generation levels:
  - Improve forecasting of generation
  - Install a battery to ensure solar / wind generation is less variable and can achieve targets
  - Solar and wind generators deliberately constrain generation levels below maximum potential and provide offers to provide Frequency Regulation Raise (may be expensive given value of LGCs)

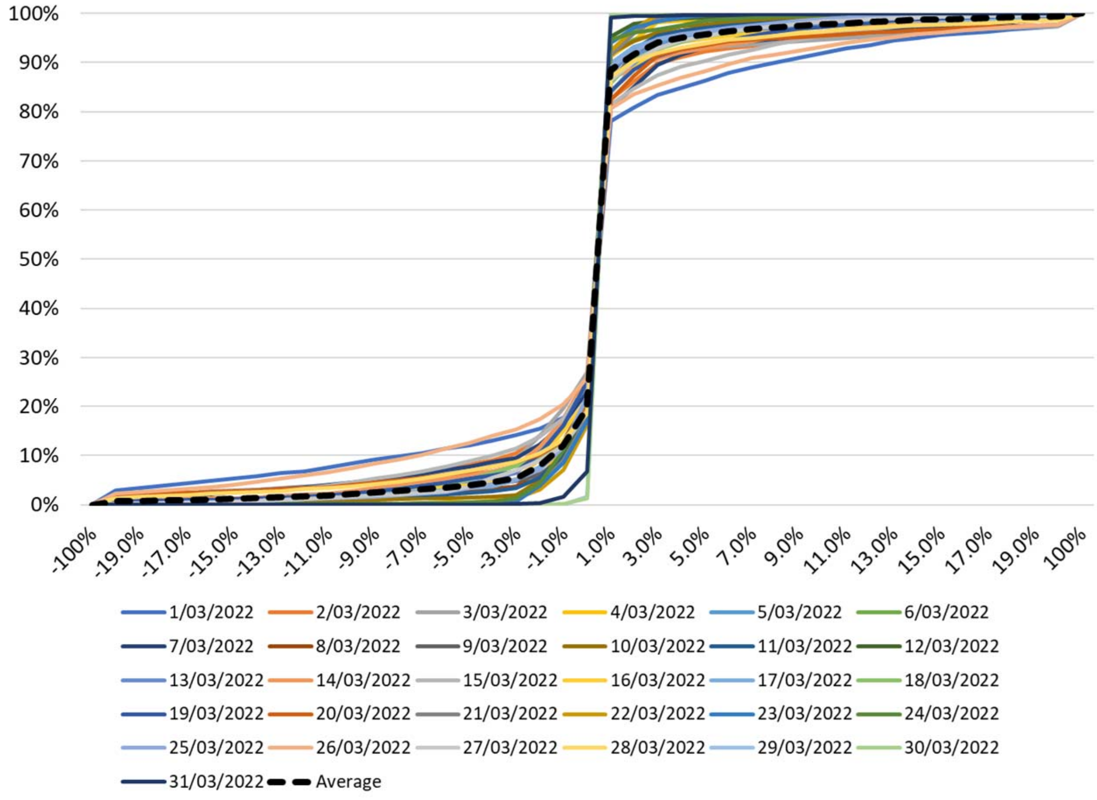
# Tolerance Method

# Percentage of Time with Large Deviations

## Extend analysis to include all 31 days in March 2022 (Greenough PV shown)

- Histogram results look similar to a normal curve on first glance
- For Greenough solar PV the single standard deviation range was ~0.4MW with a normal distribution. The 95% range produces a value of 3.2MW to 4 MW.

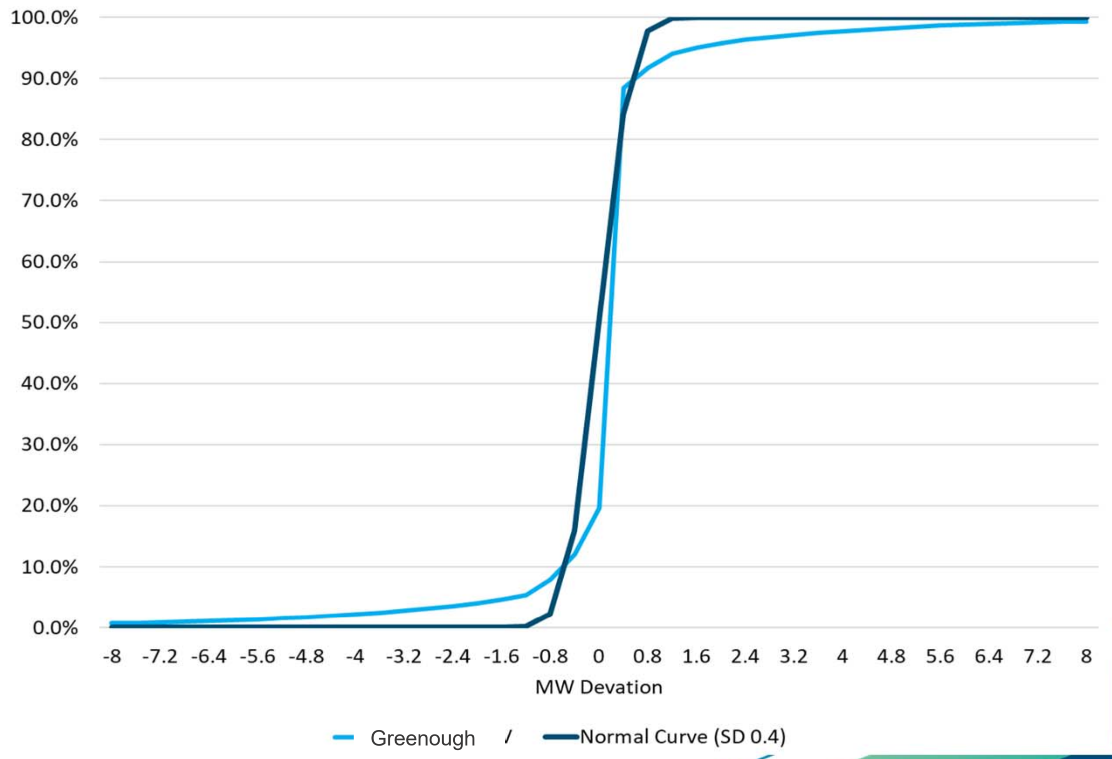
| | GREENOUGH_RIVER_PV1 | 100MW plant |
|---|---|---|
| **95% Range (1.96 SD)** | | |
| **Up MW** | -3.2 | -8 |
| **Down MW** | 4 | 10 |
| **90% Range (1.645SD)** | | |
| **Up MW** | -1.2 | -3 |
| **Down MW** | 1.6 | 4 |
| **1 SD Range** | | |
| **Up MW** | -0.40 | -1.00 |
| **Down MW** | 0.40 | 1.00 |



# Comparison with a Normal Distribution

## Extend out analysis to include all 31 days in March 2022 (Greenough PV shown) Continued

- Using a normal distribution greatly under-estimates the extreme values of the distribution
- The 97.5% and 2.5% points were chosen as the range of the distribution covering 95% of values






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

# Comparison with Current WEM Tolerance Band and 95% Confidence Interval (SCADA)

## Note existing OCGT grouped into heaving frame category (existing WEM plant only)

| WEM Plant Tolerance Ranges | | | | |
|---|---|---|---|---|
| **Plant Type** | **Tolerance Up MW** | **Tolerance Down MW** | **Average Unit Size (MW)** | **Number of Units** |
| OCGT - Aero - Small | 6 | 6 | 0 | 0 |
| OCGT - Aero - Large | 6 | 6 | 0 | 0 |
| CCGT | 7 | 7 | 208.9 | 3 |
| OCGT - Heaving Frame Unit | 6 | 6 | 74.8 | 34 |
| Coal | 10 | 10 | 223.8 | 7 |
| Solar | 6 | 0 | 47 | 3 |
| Wind | 6 | 0 | 60.9 | 17 |

| Calculated based on SCADA 95% range | | | | |
|---|---|---|---|---|
| **Plant Type** | **Tolerance Up MW** | **Tolerance Down MW** | **Average Unit Size (MW)** | **Number of Units** |
| OCGT - Aero - Small | 0 | 0 | 0 | 0 |
| OCGT - Aero - Large | 0 | 0 | 0 | 0 |
| CCGT | 4.2 | 6.3 | 208.9 | 3 |
| OCGT - Heaving Frame Unit | 1.5 | 2.2 | 74.8 | 34 |
| Coal | 4.5 | 6.7 | 223.8 | 7 |
| Solar | 3.8 | 4.7 | 47 | 3 |
| Wind | 3.7 | 4.3 | 60.9 | 17 |

# Total Tolerance MW

- Below is a sum of (tolerance x number of units).
  - Assumes 100% of tolerance usage by all plant during a single point in time, which is extremely unlikely as the WEM has over 60 plants
  - The majority of these plants are not correlated under normal operation as each unit runs independently.
  - Wind and solar may show correlation due to location clustering and wind/solar conditions
- The biggest reduction in the sum is from OCGT due to a larger number of units

| WEM Plant Tolerance Ranges | | |
|---|---|---|
| Plant Type | Tolerance Up MW Sum | Tolerance Down MW Sum |
| OCGT - Aero - Small | 0 | 0 |
| OCGT - Aero - Large | 0 | 0 |
| CCGT | 21 | 21 |
| OCGT - Heaving Frame Unit | 204 | 204 |
| Coal | 70 | 70 |
| Solar | 18 | 0 |
| Wind | 102 | 0 |
| Total | 415 | 295 |

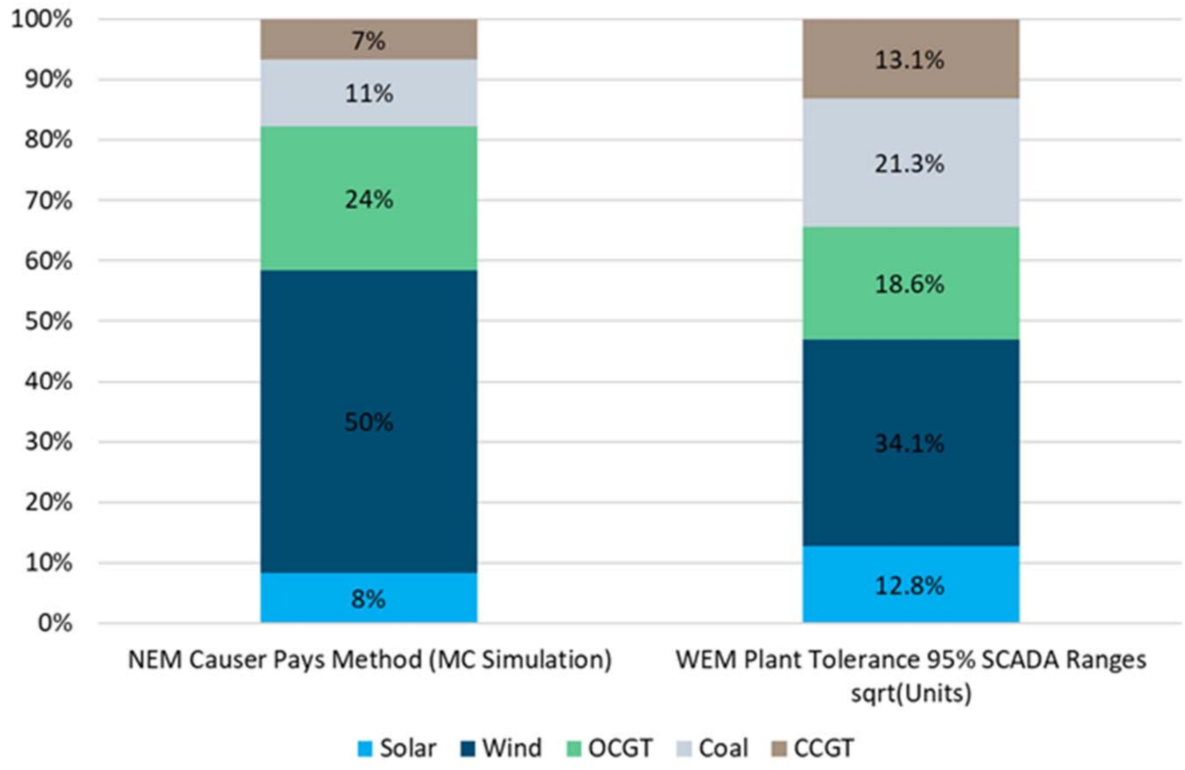
| Calculated based on SCADA 95% range | | |
|---|---|---|
| Plant Type | Tolerance Up MW Sum | Tolerance Down MW Sum |
| OCGT - Aero - Small | 0 | 0 |
| OCGT - Aero - Large | 0 | 0 |
| CCGT | 12.6 | 18.9 |
| OCGT - Heaving Frame Unit | 51 | 74.8 |
| Coal | 31.5 | 46.9 |
| Solar | 11.4 | 14.1 |
| Wind | 62.9 | 73.1 |
| Total | 169.4 | 227.8 |

# Method for Applying Tolerance Ranges to Determine Cost Recovery

- Using the Tolerance Ranges established from the 95% Confidence Interval for SCADA data, apportion Frequency Regulation cost recovery and compare with NEM Causer Pays method applied to the WEM

# Results of Applying Tolerance Ranges to Determine Frequency Regulation Cost Recovery Percentages

- The Tolerance method results in higher cost recovery from solar plant and lower cost recovery from wind plant compared to the NEM Causer Pays method
- The reduction in wind and increase in solar is caused by the small number of solar PV currently in the WEM
- Less units in a technology type leads to large variance relative to installed MW




Note: sample restricted to generators ≥ 30 MW

# Recommendation on Allocation of Frequency Regulation Costs

# Recommendation on Allocation of Frequency Regulation Costs

- Both the NEM Causer Pays, and Tolerance methods attempt to attribute costs to the facilities/loads that impose risks and cause costs to be incurred for the provision of Frequency Regulation services
- Both methods will provide incentives for participants to take actions to reduce the incidence of Frequency Regulation costs (i.e., better forecasting, installation of storage facilities, intermittent generators providing ESS raise services, etc.)
- However, the NEM Causer Pays method may be preferred because:
  - benefits from a common approach for participants operating in both the NEM and WEM
  - cost savings for AEMO to developing and maintaining processes and systems across the NEM and WEM

Recommendation: Adopt NEM Causer Pays method to allocate Frequency Regulations costs generators and Loads in the WEM

# Assessment of Allocation of Contingency Reserve Raise Costs

# Contingency Reserve Raise

- Contingency Reserve Raise costs are recovered from Registered Facilities injecting above 10 MW based on their cleared generation and ESS in the relevant Dispatch Interval, using a runway method
- The runway method allocates Contingency Reserve costs to causers of contingencies, commensurate with the extent to which they have contributed to the additional procurement Contingency Reserve Raise Requirement
- The risks for the system is the loss of an individual dispatchable generating unit, and/or specific network asset that has dispatchable generating units connected to that asset
  - This becomes complicated when we have Aggregated Facilities with multiple generators and multiple connection points
- If we have two generating units that can be dispatched separately and two connection points, and both are regarded as Aggregated Facilities, the current application of the runway method would allocate costs to the combined total of their sent-out generation
  - This overestimates the costs (and risks) of Contingency Reserve Raise services to that Aggregated Facility (the risk is associated with each independent dispatchable generating unit, not the aggregate), which is not consistent with the causer pays principle

# Contingency Reserve Raise (continued)

- To align with causer pays principles, ensure that the runway method is only applied to individual dispatchable generating units – this will require changes to the definition of a Facility and Aggregated Facility
- Aggregation of Facilities by AEMO will only be approved in certain circumstances (i.e. it does not adversely impact on provision of ESS) – a requirement could be added to require the ability to accurately allocate Contingency Reserve Raise costs

# Next Steps

# Next Steps

- Develop cost allocation methodologies, accounting for feedback from today's presentation
  - Send to CARWG on 20 September 2022 for discussion at CARWG meeting on 27 September 2022
  - Update and send to MAC 8 November 2022 for discussion at MAC meeting 15 November 2022
- Cost Allocation draft submission to MAC on 8 November (for MAC meeting on 15 November 2022).
- Draft consultation paper
  - Paper to CARWG on 15 November 2022 for discussion at CARWG meeting on 22 November 2022
  - Updated paper to MAC on 6 December 2022 for discussion at MAC meeting on 13 December 2022

We're working for
Western Australia.