Meeting Agenda

Meeting Title:	Cost Allocation Review Working Group (**CARWG**)
Meeting Number:	2022_09_27
Date:	Tuesday 27 September 2022
Time:	1:00 PM to 2.45 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_08_30	Chair	Noting	2 min
4	Action Items	Chair	Discussion	2 min
5	Assessment of Cost Recovery Options: (a) allocation of Market Fees; (b) allocation of Frequency Regulation costs; (c) allocation of Contingency Reserve Raise costs; (d) allocation of Contingency Reserve Lower costs; and (e) allocation of Non-co-optimised Essential System Services costs.	Marsden Jacob	Discussion	1 hour 30 min
7	Next Steps	Chair	Noting	2 min
8	General Business	Chair	Discussion	5 min
	Next Meeting: 22 November 2022			

Please note this meeting will be recorded.

Minutes

Meeting Title:	Cost Allocation Review Working Group (**CARWG**)
Date:	30 August 2022
Time:	12:30pm – 2:23pm
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	
Genevieve Teo	Synergy	
Paul Arias	Shell Energy	
Mena Gilchrist	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 12:30pm.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Minutes of CARWG Meeting 2022_06_07** Draft minutes of the CARWG meeting held on 7 June 2022 were distributed in the meeting papers on 24 August 2022. The CARWG accepted the minutes as a true and accurate record of the meeting.	

Item	Subject	Action
	ATCION: CARWG Secretariat to publish the minutes of the 7 June 2022 CARWG meeting on the CARWG web page as final.	**CARWG Secretariat (31/08/2022)**
4	**Action Items** The papers was taken as read. The Chair noted that Ms Gilchrist has provided a response on action item 5 and that this item is closed.	
5	Mr Draper restated the objectives and guiding principles for the review and the priority for the assessment of services; and noted that the policy assessment will consider the causer-pays and beneficiary-pays principles, where practical and applicable. Mr Draper provided an overview of timeline for the review. **Assessment of the Methods to Allocate Market Fees** Mr Draper noted that MJA has modelled the impact of the following three options on Market Participants: • the current Wholesale Electricity Market (**WEM**) method; • the National Energy Market (**NEM**) method; and • a hybrid method. Mr Draper noted the following regarding the analysis of the hybrid method: • Market Fees were not allocated to network companies because it would be inefficient to charge fees to network companies that would then pass through the costs in their Access Arrangement. • For generators, the fees were allocated 50% on capacity and 50% on generation output, and was based on sent out generation, but could include marginal loss factors and looking at generation to the node. • For market customers, the fees were allocated 50% on grid demand and 50% on Individual Reserve Capacity Requirement (**IRCR**). • For simplicity, the Market Fee analysis only covered AEMO fees, not Coordinator Fees or Economic Regulation Authority (**ERA**) Fees. Mr Arias recalled discussion from a previous meeting that consideration would be given to an option where Market Fees would be allocated directly to customers and asked if this had been progressed. • Mr Draper noted that this idea arose because of an Ofgem (UK) recommendation to allocate Balancing Service Use of System (**BSUoS**) fees directly to customers. However, allocating fees directly to customers was viewed as a significant departure from the current arrangements.	

Item	Subject	Action
	• Ms Guzeleva noted that the causer-pays principle is key, that generators are a large causer of AEMO costs, and that shifting all Market Fees to consumers may reduce the incentive for generators to scrutinize AEMO costs. • Mr Arias noted that consumers will ultimately incur the costs from the Market Fees and contended that putting the fees first through the generators in such a highly contracted market would introduce inefficiencies. • Ms Guzeleva suggested that causer-pays is a more important principle than efficiency and we would not be abiding by that key principle if we allocate costs directly to consumers. • Mr Schubert agreed that causer-pays should be the dominant principle, and that it could be argued that consumers cause all of the costs, but noted that this would remove incentives from upstream providers. • Ms White suggested that there is a competitive neutrality issue because Synergy could not pass Market Fees on to customers via regulated tariffs, but that other retailers would have to pass them on, which would make them less competitive. Ms White suggested there is a greater case for levying Essential System Services (**ESS**) costs on generators because this is more likely to incentivise generators to change their behaviour to minimise costs. • Ms Guzeleva noted that the retail market is outside of the scope of the WEM and that allocating costs to retailers is the only way that costs can be passed to end users. • Ms Guzeleva noted that the majority of AEMO's costs are from market processes that deal with market generators, including; certification, capacity credits, obligations, refunds, dispatch and market development. • Ms White agreed that generators cause most of AEMO's costs, and that causer-pays is a good principle when it can send signals to people to change their behaviour. Ms White suggested that the beneficiary-pays principle is appropriate if the causer-pays approach does not send signals for market participants to change their behaviour. • Mr Arias noted that the bilateral contract market may prevent these costs from being passed through to customers, that allocating Market Fees to generators would not incentivise behavioural change, and that the ERA is responsible for scrutiny of AEMO costs. • Mr Arias noted that the only behaviour that the current allocation mechanism incentivises is behind the meter (**BTM**) investment, which is creating other problems and costs and is caused by customers.	

Item	Subject	Action
	• Ms Guzeleva suggested that the current Market Fee allocation method should be retained if agreement cannot be reached on a causer-pays method. • Mr Carlberg suggested that generators cannot pass through Market Fees, so it is not efficient to levy these costs on generators and suggested that market reform is driving most of AEMO's cost increases. • Ms Guzeleva noted that most of the current market reforms are benefiting generators through moving closer to real time and from having competitive ESS markets, and that the majority of generators have been pushing for those reforms. Ms Guzeleva agreed that MJA could do the analysis for an option to pass costs to consumers on a per MWh basis and present this along with other options at the CARWG meeting in September 2022. Mr Draper indicated that this analysis would not be based on gross MWh because there is no mechanism to measure gross MW hours due to the lack of smart metering. In presenting the results of MJA's analysis on slides 11-13, Mr Draper noted that allocating fees based on capacity leads to bigger changes for units that have low capacity factors, whereas units with higher capacity factors see a fee reduction. Mr Kurz asked why the analysis for Bluewaters was not included. Mr Draper indicated that the analysis had been done for every generator in the system, but that only selected units had been presented, and it that all analysis could be shared. Ms Guzeleva noted the main point was that peaking plant would pick up more fees with allocation based on mix of MW and MWh. Mr Draper noted that the analysis of the impact of the options for allocating Market Fees on retailers (slide 14) was based on confidential information and was therefore not shared. However, using IRCR as part of the allocation method would result in Synergy paying relatively more and other retailers paying relatively less. Mr Kurz noted that the market exists to deliver electricity to end consumers and the goal is to determine the most effective way to allocate costs of that energy to the customer. Mr Draper noted that, if parties cannot react to the price signal from the Market Fees, then the hierarchy suggests that cost allocation should move from the causer-pays principle to the beneficiary-pays principle, and that the market reforms are happening for a variety of reasons, including decarbonisation, and are benefiting a range of parties, not just consumers. Ms Guzeleva noted that residential consumers also cannot react to Market Fees and are not the only beneficiary.	

Item	Subject	Action

Assessment of the Methods to Recover Frequency Regulation Costs

Mr Draper indicated that three methods have been considered to allocate frequency regulation costs:

- the current WEM method;
- the NEM causer-pays method; and
- a proposed new Tolerance Method.

Ms White sought asked if the NEM causer-pays method referred to taking SCADA every four seconds, matching that against the target and then summing the deviation between that target and the SCADA point for every four second interval within a trading interval. Mr Draper replied that was correct.

Mr McKenzie provided an overview of the approach to analyse the NEM causer-pays method:

- For both Lower and Raise, MJA looked back at the deviations at a plant level, using the 28-day monthly reports for about three years, and put together a distribution of the expected deviation based on a per MW of installed capacity for each technology type. This gave an outlook of the performance of each technology type and a variation.
- MJA applied this distribution to the installed capacities in the WEM, used that to produce a Monte Carlo model, and ran a few hundred simulations to get a breakdown of the contributions between demand and generators, and to further breakdown the generation contributions into technology types.

Mr McKenzie presented the results from the simulations and compared the cost allocations for the current WEM method and the NEM causer-pays method (slides 22-27).

- Ms White asked if there is a skew on slides 22 and 23, and if that indicated more demand for the upward or downward service.
    - Mr McKenzie noted the deviation is much bigger on raise than on lower for both wind and solar, and that the raise had a bigger variation for solar and wind because it is harder for solar to push up generation than down.
- Mr Parrotte asked if slide 27 shows the 'ideal' that we should be trying to achieve in the Frequency Regulation cost allocation, based on one month data simulation, and if deviations of units providing Ancillary Services had been excluded.
    - Mr Draper noted that MJA had looked at the full capacity and included units providing the ancillary services, and indicated that MJA could adjust for this.

Item	Subject	Action
	- Mr Parrotte indicated that this might explain why Open Cycle Gas Turbines (**OCGTs**) have a higher representation, as they do most of the frequency regulation. Mr Draper agreed that OCGTs are likely overrepresented and would have less variation once this adjustment is made. - Mr Schubert noted that this is probably why OCGTs participate more in the frequency regulation and noted that solar down is more likely to happen due to cloud cover, where solar cannot go higher than it does on a clear day. • Ms White asked if you deviate downwards, and your next SCADA point is above your target, would you take the difference between the previous SCADA point and the new SCADA point, or between the new target and the new SCADA point. - Mr McKenzie indicated that MJA did not look at the difference between SCADA points, rather the difference between the dispatch targets and the SCADA points. Mr Draper noted that the current methodology does not provide an incentive to the participants that cause deviations to look at strategies to reduce the deviations, and that there are numerous behaviours that could result from adopting the NEM causer-pays method. Mr Parrotte noted that Load recovery cost was also presently based on MWh, yet it is load variability that drives Frequency Regulation quantity, and therefore cost. Ms White noted the NEM approach seems sensible in principle and has the benefit of it already being in use in the NEM, and asked if there is any indication of how much it would cost for AEMO to implement. • Mr Draper noted that AEMO had spreadsheet models and had invested in those overheads. • Ms Guzeleva noted that consistency with the NEM has benefits given that many market participants operate across state borders. Mr McKenzie presented on the methodology and results for the analysis of the tolerance method (slides 29-35). Mr Draper noted a correction to slide 32 – MJA had included the aeros in with the heavy frame units and indicated that aeros will be split out in the later analysis. Mr Draper noted that, whilst AEMO proposed the tolerance method, it does not currently use or plan to use this method in the NEM. Instead, the NEM is looking at changes to its current causer-pays methodology.	

Item	Subject	Action
	Ms Guzeleva noted the tolerance method is relatively complex and it is important to consider simplification because lack of predictability has been raised as an issue. In response to a question from Ms White, Mr Draper indicated that the results are presented by technology group to keep it confidential and that moving into particular plants and technologies would require another step. Mr Draper noted that the results for the NEM causer-pays method and tolerance method have similar patterns and provide similar incentives. The recommendation is to adopt the NEM causer-pays method to allocate Frequency Regulation cost to Generators and Loads in the WEM because it is more transparent and is already in use in the NEM. Ms Gilchrist noted that a rule change proposal is under consideration in the NEM that includes an incentive payment for generators that contribute to helping correct frequency deviations and asked if consideration was given to how this might affect generators in the WEM. Mr Draper noted they had not modelled the rule changes, just the current methodology. Mr Parrotte asked if the NEM method would result a 50/50 generator/load allocation. • Mr Draper responded that was correct and that when we looked at the very the causes of the variations, the finding was that it was 50/50 between generators and loads. • Mr Parrotte noted that the allocation is currently about 20% generators and 80% load, so this is quite a change, and asked if the load allocation would to continue to be based on MWh, noting that it would be good to be variability based, but this would require meters on every customer. Mr Draper noted that Loads in the NEM are allocated the residual after everything else is allocated. • Mr Parrotte sought to clarify if retailer allocations account for whether the retailer has a lot of flat loads versus a retailer with lots of variable loads, or if it was purely a MWh allocation. Mr McKenzie indicated that NEM allocations are on a MWh basis for each region. Ms White asked if there was a view on how the split may change over time. Ms Guzeleva noted the split is likely to move more to load than generation. Mr Draper agreed, as solar and wind take actions to improve their forecasting or incorporate storage into their sites. **Assessment of Methods to Allocate of Contingency Reserve Raise Costs** Mr Draper noted that there may be a problem with how the runway approach applies to aggregated facilities as they are currently defined under the WEM Rules (slides 39-40).	

Item	Subject	Action
	Mr Draper noted that network contingencies are a part of the existing runway method. Mr Schubert and Mr Parrotte asked if the network should be charged if it forms the largest contingency. Ms Guzeleva noted that this may be the case. Ms White noted that this was considered when the runway method was designed and agreed that it may be a good principle. ~~Mr Draper responded that network contingencies are a part of the existing runway method.~~ Mr Draper clarified that networks will not be charged Contingency Reserve Raise costs calculated using the runway method but will be charged one third of the Rate of Change of Frequency (RoCoF) costs calculated using the runway method. Ms White provided the example of Collgar having an aggregated facility with two connection points and two halves and can operate separately. Mr Draper suggested that this would mean that Collgar's contingency would be half its capacity. Ms Guzeleva noted that this issue was picked up in the final stages of Tranche 5, where it was agreed that this should be fixed, but EPWA ran out of time to fix it in Tranche 5.	
	ACTION: EPWA to present analysis for an option to allocate Market Fees only to customers at the CARWG meeting in September 2022.	**EPWA (27/09/2022)**
7	**Next Steps** A set of proposals will be presented to the CARWG for discussion at its meeting on 27 September 2022 and will then be taken to the MAC on 11 October 2022.	
8	**General Business** No general business was discussed. The next CARWG meeting is scheduled for 27 September 2022.	

The meeting closed at 2:23pm.

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

Agenda Item 4: CARWG Action Items

Cost Allocation Review Working Group (**CARWG**) Meeting 2022_09_27

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
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	**Closed** AEMO provided a response to the CARWG by email on 30/08/2022.
6	CARWG Secretariat to publish the minutes of the 7 June 2022 CARWG meeting on the CARWG web page as final.	CAR Secretariat	2022_05_09	**Closed** The minutes were published on the Coordinator's Website on 31/08/2022.

Government of **Western Australia**
Energy Policy WA

Cost Allocation Review

Assessment of Cost Recovery Options

27 September 2022

Presenter: Grant Draper, Marsden Jacob Associates

Working together for a
brighter energy future.

Agenda

- Timeline and Purpose
- Assessment of Cost Recovery Options
  - (a) Allocation of Market Fees
  - (b) Allocation of Frequency Regulation Costs
  - (c) Allocation of Contingency Reserve Raise Costs
  - (d) Allocation of Contingency Reserve Lower
  - (e) Allocation of Non-co-optimised ESS
- Next Steps

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: • Identify the options that can be practically and efficiently applied in the WEM to allocate the Market Fees and each ESS cost; • Assess each option against the guiding principles; • Model the impact of each of the options on Market Participants; and • Recommend a preferred option for the allocation of the Market Fees and each ESS cost.	July-September 2022
Step 3 – Methodology Development	
Develop the details of the cost allocation methodologies in consultation with the MAC Working Group	September-October 2022
Develop and publish a consultation paper on the design for the allocation methodologies and seek stakeholder comments.	November-January 2023
Develop publish an information paper on the detailed design for the allocation methodologies.	March 2023
Step 4 – Formal Rule Change	
Develop one or more Rule Change Proposals for consideration by MAC, and approval by the Coordinator and Minister.	April 2023

(a) Allocation of Market Fees

Market Fees Cost Allocation

MAC supported:

- High priority for assessment of alternative methods to allocate Market Fees
- Three options to be developed and compared with the current allocation method in the WEM
  - Current NEM Practice
  - Hybrid Option
  - Market Customers only (added at the CARWG meeting on 30 August 2022)

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

Current 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
  - 50% charged on capacity (MW)
  - 50% on grid generation (MWh)
- For market customers
  - 50% based on grid demand (MWh)
  - 50% based on number of connections

Hybrid Method

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

Market Customers Only

- 50% based on grid demand (MWh)
- 50% based on IRCR (MW)

AEMO WEM Fees 2022/23

WEM Fees	Budget	Notes
Revenue Requirement	$41.9m	
Consumption	17,950 GWh	
WEM Market Operator Fee	$0.4913/MWh	
WEM System Management Fee	$0.6646/MWh	
WEM Fee	$1.1559/MWh	Paid by generators and loads
WEM fee benchmark	$2.3118/MWh	Impact on loads
Derived Annual Revenue	$41.9m	Cost recovery
Market participant buying WEM Services – annual revenue	$20.95m	50%
Market participant selling WEM services – annual revenue	$20.95m	50%

Cost Recovery by Method

Allocation of AEMO Market Fees Only - 2022-23				
Cost Allocations by Participant Type	**Current WEM Fees $**	**NEM Fee Approach $**	**Market Customer Only $**	**WEM Hybrid Fee $**
Wholesale Market Participant	20,950,298	16,395,587	0	20,950,149
Market Customers	20,950,298	20,371,780	41,900,000	20,950,000
Western Power	0	5,132,750	0	0
Total	41,900,596	41,900,117	41,900,000	41,900,149
Cost Allocations to Generators Only	**Current WEM Fees $**	**NEM Fee Approach $**	**Market Customer Only $**	**WEM Hybrid Fee $**
SYNERGY	8,095,565	6,713,114	0	8,577,963
ALINTA	3,496,297	2,855,362	0	3,648,559
OTHER	9,358,436	6,827,110	0	8,723,627
Total	20,950,298	16,395,587	0	20,950,149
Cost Allocations to Customer Type (via direct charges on Market Customers Only)	**Current WEM Fees $**	**NEM Fee Approach $**	**Market Customer Only $**	**WEM Hybrid Fee $**
Residential (no BTM DER)	9.58	13.40	25.84	12.92
Residential (3 kW Rooftop PV)	7.14	12.23	23.42	11.71
Residential (5 kW Rooftop PV)	3.88	10.66	20.19	10.09
Small Business (no BTM DER)	25.81	21.22	64.08	32.04
Small Business (10 kW Rooftop PV)	12.96	15.03	51.35	25.68
Large Commercial (no BTM DER)	6,278.87	3,033.00	11,986.01	5,993.00
Large Commercial (250 kW Rooftop PV)	6,122.57	2,957.72	11,687.64	5,843.82

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

Allocation to Market Generators

Participant	Plant_ID	Annual GWh	Maximum Capacity (MW)	Capacity Factor	Current WEM Fee $	NEM Fee / WEM Hybrid Approach $
ALBGRAS	ALBANY_WF1	57.51	21.60	0.30	67,762	70,902
ALBGRAS	GRASMERE_WF1	43.24	13.80	0.36	50,939	49,122
ALINTA	ALINTA_PNJ_U1	667.22	143.00	0.53	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_WWF	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
COLLGAR	INVESTEC_COLLGAR_WF1	663.21	218.50	0.35	781,364	765,183
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	MWF_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
GRIFFIN2	BW2_BLUEWATERS_G1	1,352.60	217.00	0.71	1,593,579	1,168,720
GRIFFINP	BW1_BLUEWATERS_G2	1,483.45	217.00	0.78	1,747,734	1,245,797

- 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 WEM Hybrid Method – Retailers

- IRCR and metered scheduled data by electricity retailer is confidential, so only commentary on the results is presented
- 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 Market Customers – WEM Hybrid

Allocation to Market Participants 2021/22		
Participant	**Current WEM Fees**	**Hybrid WEM Fees**
Synergy	$18,905,324	$21,726,861
Alinta	$5,622,798	$5,438,167
Perth Energy	$2,341,089	$1,916,413
Other	$15,228,570	$12,963,018
Total	$42,097,781	$42,044,459

- 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 customers

Market Fees Recommendation

- Charging generators and market customers on a 50:50 basis is consistent with causer-pays and beneficiary-pays principles
- Generators and market customers are all commercial entities and benefit from participation in the WEM
- Generators and market customer all use AEMO services, and rule and procedure changes account for all participants' viewpoints
- Market fees are a cost recovery mechanism – they do not provide a price signal to either generators or market customers (neither is likely to be able to change their behaviour to materially reduce fees)
- While it may be administratively easier to charge fees only to market customers (no pass through via wholesale contracts), the burden of levying fees on both generators and market customers is small
- No major benefit has been demonstrated to changing the fee allocation between each participant class
- 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 are driven by the number of participants and number of assets, not by sent out generation
    - AEMO will spend time and resources on planning, certification, testing and rule changes to facilitate entry of flexible generation, with low capacity factors and storage (e.g., OCGT-aero, pumped hydro and BESS)
- Charging market customers based on IRCR (50%) ensures recovery of costs from retailers with a high proportion of customers with rooftop PV
    - This reduces the inequity from recovering Market Fees based on metered consumption, which customers with rooftop PV can minimise

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

(b) Allocation of Frequency Regulation Costs

Frequency Regulation Cost Allocation

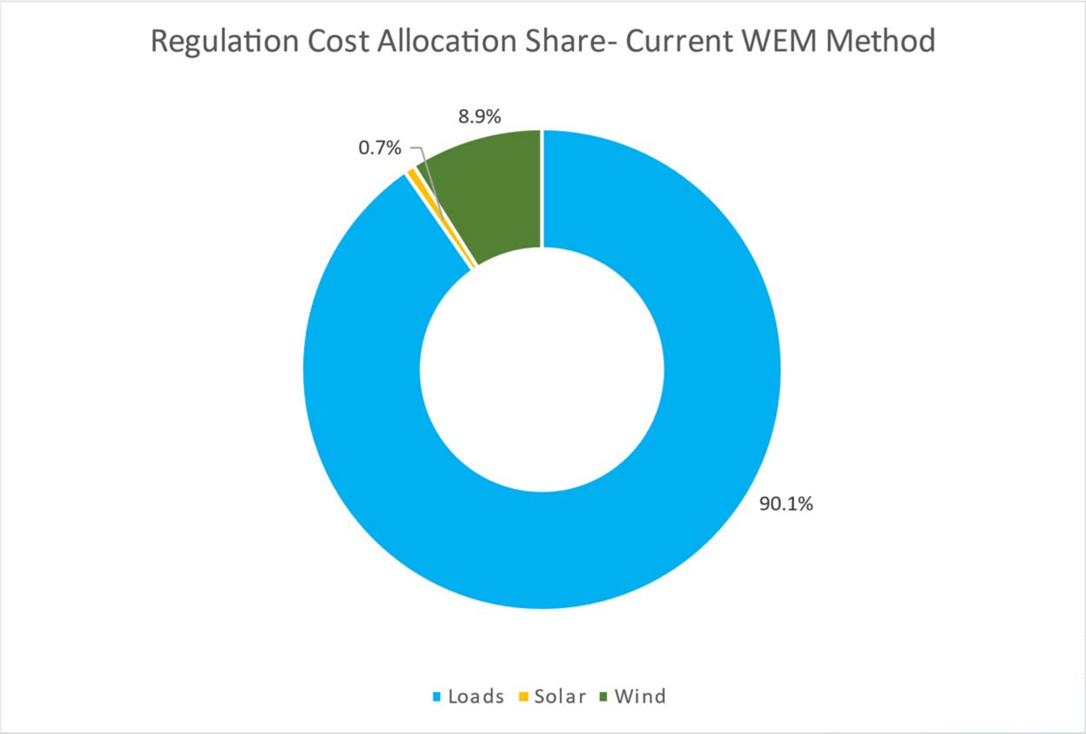
MAC supported assessing:

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

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

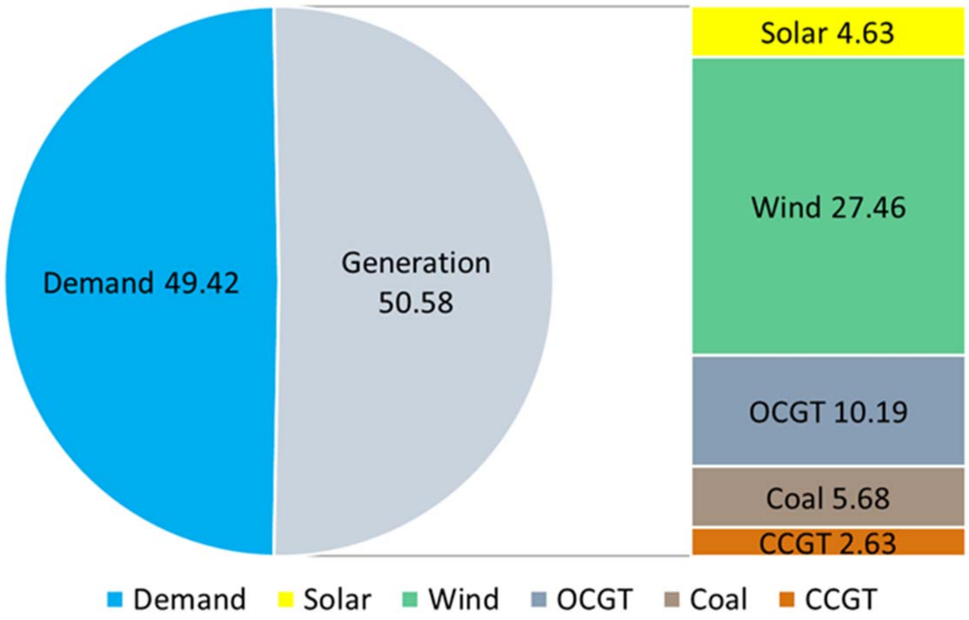


Current NEM Causer Pays Method

Results of 100 simulations of applying the distributions to WEM generators with Average WEM 28-day load (1,376 GWh)

- 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
  - o Yandin
  - o Warradarge

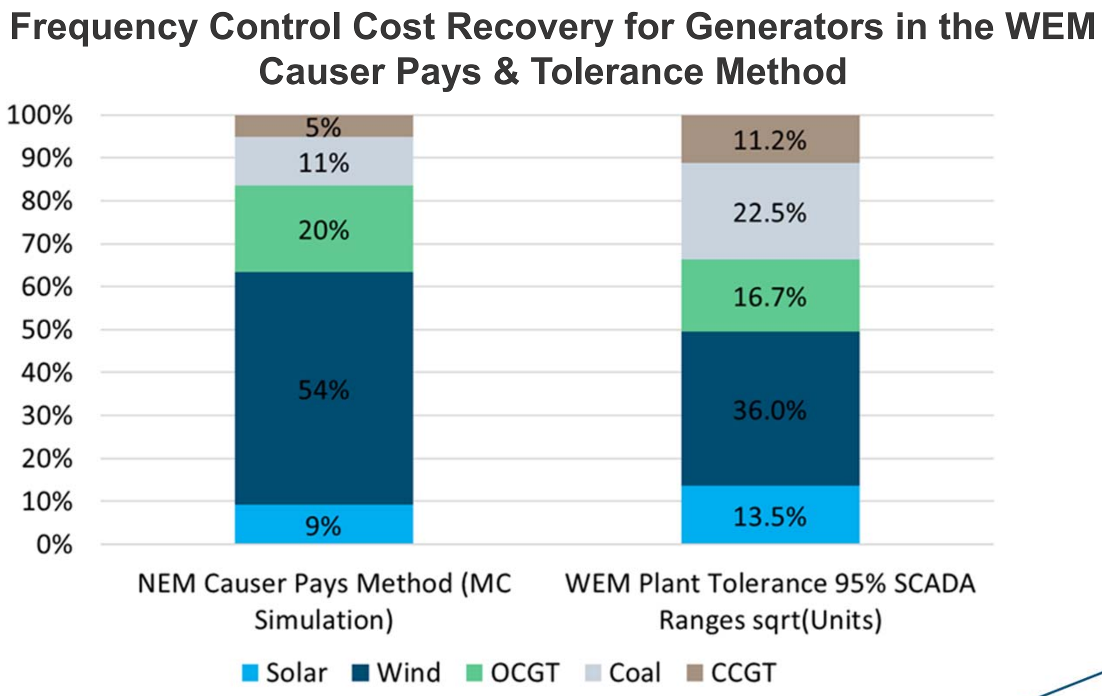
Frequency Control Cost Recovery in the WEM – Causer Pays



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

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

New NEM Causers Pays Method

- The AEMC has approved a rule change to amend the NEM Causer Pays methodology for FCAS cost recovery to provide performance payments to Facilities that make positive contributions to improving System Frequency during a trading interval
- AEMO is currently working on how to implement the rule change
- This rule changes also significantly simplifies the NEM Causer Pays method
  - Marsden Jacob is assessing the impact of incorporating the simplifications into a NEM Causer Pays Methodology for Regulation Services

Allocation of Frequency Regulation Costs

- Both the current the NEM Causer Pays and Tolerance methods attribute costs to the facilities/loads that impose risks and cause costs to be incurred for provision of Frequency Regulation services
- Both methods will provide incentives for participants to take actions to reduce Frequency Regulation costs (better forecasting, install storage facilities, intermittent generators providing ESS raise services, etc.)
- However, the new NEM Causer Pays method may be preferred because
  - the new method is much simpler to implement compared to current Causer Pays method
  - benefits from a common approach for participants operating in both the NEM and WEM
  - cost savings for AEMO to develop and maintain processes and systems across the NEM and WEM

Recommendation: Adopt the NEM User Pays method to allocate Regulation costs, consistent with either the current or proposed new method

Next Steps: MJA to analyse the impact of the proposed new NEM Causer Pays method to allocate Regulation Costs and discuss with the CARWG

(c) Allocation of Contingency Reserve Raise Costs

Contingency Reserve Raise

- Contingency Reserve Raise costs are recovered from Registered Facilities injecting >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 of the Contingency Reserve Raise Requirement
- The risk 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 an Aggregated Facility (none are classified as this in the WEM currently) has two generating units with separate connection points and that can be dispatched separately, the runway method will allocate costs to the combined total of their sent-out generation
  - This may overestimate Contingency Reserve Raise costs (and risks) to that Aggregated Facility (the risk is associated with each independent dispatchable generating unit, not the aggregate), which may not be consistent with the causer-pays principle

Contingency Reserve Raise

- To align with the causer-pays principle, 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
- A dispatchable unit in this context refers to a unit that
  - Can adjust output in response to an instruction from System Management (this includes renewable generators that can reduce output in response to a dispatch instruction)
  - Has a set of separate coal and gas units that are independently controlled
  - Has a set of inverters that are controlled independently at a single plant
- Collgar Wind Farm was provided as an example of a plant that has two dispatchable units (not currently classified as an Aggregated Facility) – should these be treated as two dispatchable units for the purposes of allocating Contingency Reserve Raise costs?
  - Further analysis needs to be undertaken to consider both Aggregated Facilities and existing plants that have multiple dispatchable units

(d) Allocation of Contingency Reserve Lower Costs

Contingency Reserve Lower Requirement

- Contingency Reserve Lower is required to cover the risk of a material decrease in system frequency due to a loss of single large load, or multiple loads on a single network element
- The largest credible load rejection event is 120 MW, based on the loss of the Eastern Goldfields region or the Boddington Gold Mine
- The Contingency Reserve Lower service for 2021-22 remains up to a maximum of 90 MW, which is 120 MW (largest continency event) minus 30 MW for Load Relief (loads draw more power when system frequency is high)
- The potential introduction of a large-scale BESS into the SWIS (i.e., 250 MW) would more than double the largest credible load rejection contingency – this could increase the Contingency Reserve Lower service to 220 MW (i.e., 250 MW – 30 MW Load Relief)

Current Cost Allocation Method

With 250 MW BESS entering the SWIS

Cost Recovery in a Trading Interval Under Current Method for LRR

Based on 2021-22 LRR Costs			
Requirement (MW)	220	Interval Cost ($)	Cost Allocation (%)
Unit Cost ($MW per Interval)	3.61	794.91	
Large Battery (MW)	250	103.50	11.52%
Large Load (MW)	120	49.68	5.53%
Small Load (MW)	1800	745.23	82.95%
Total Load (MW)	2170	898.42	100.00%

Notes:

- Small load is effectively equal to the notional wholesale meter
- Assuming large load is a non-dispatchable load equipped with an interval meter.

- It is currently proposed that Contingency Reserve Lower costs will be recovered from loads based on their share of consumption in the trading interval
- This is consistent with the current cost allocation method for Load Rejection Reserve

Cost Reflective Approach to Contingency Reserve Lower

Cost Recovery in a Trading Interval under an Alternative Runway Method

Three Load Case		Tranche Cost Allocation				
Generator	Load Size (MW)	200 to 300 MW Tranche 1	120 to 200 MW Tranche 2	120 MW and below Tranche 3	Total (MW)	
Load A	250	50	80	120	250	
Load B	120	0	0	120	120	
Load C	Small Loads	0	0	1800	1800	
Tranche Amount (MW)		50	80	2040	2170	
Cost Share Interval		29%	29%	42%	100.0%	Share
Load A	250	230.5	230.5	19.6	480.7	60.5%
Load B	120	0.0	0.0	19.6	19.6	2.5%
Load C	Small Loads	0.0	0.0	294.6	294.6	37.1%
Total		230.5	230.5	333.9	794.9	100%

A. Under this revised method, BESS (Load A) bears 60% of costs in the trading interval when recharging, Small loads (37.1%) and the non-dispatchable load (120 MW) only 2.5%

B. This method is more consistent with the causer-pays principle whereby the party that gives rise to additional Contingency Reserve Lower service (the BESS) pays most of the cost

C. Additional analysis required to see if this can be done without tranches (which would create boundary issues) and calculated numerically

D. Need to adjust methodology to cater for future network contingencies that may also exceed 120 MW

Recommendation:

- The requirement for the Contingency Reserve Lower service is a function of the size of the potential load that may be lost
  - This is analogous to how the largest generator is the main causer of the requirement for Contingency Reserve Raise service
- A causer-pays approach consistent with the method used for Contingency Reserve Raise suggests that a modified ‘runway method’ could be applied to allocate Contingency Reserve Lower costs to the largest loads operating in a trading interval
- This will be important given current plans to build BESS of up to 250 MW in the SWIS
  - When a 250 MW BESS is operating, the Contingency Reserve Lower requirement is likely to increase to 220 MW (only 90 MW today), and most of the additional costs for this requirement should be borne by that BESS.

Question: Does the CARWG support exploring allocating Contingency Reserve Lower costs using a runway approach?

Next Steps: MJA to develop a runway method that could be applied to Contingency Raise Lower costs and analyse the impact of this method on market participants

(e) Allocation of Non-co-optimised ESS

RoCoF Control (Inertia)

- While generators, network facilities and large customers are not the causers of low inertia, they will benefit from improved ride-through capability (i.e., equipment that can cope with sudden variations in system frequency)
- Generators, network facilities and large customers should be incentivised to install equipment with ride-through capability via RoCoF Control charges
- Attributing costs to generators, loads and Western Power is consistent with the causer- and beneficiary-pays principles
- Cost attribution levels should be determined on the basis of the benefit that each party receives from improving ride-through capability of equipment.

Recommendation: There is no need to change the current cost allocation method for RoCoF services

System Restart Service

- The requirement for System Restart Service (Black Start) is not driven by the actions of Market Participants, so it would be difficult to attribute system wide failures and the requirement for System Restart Service to any one participant or group of participants (identifying causers)
- System Restart Service pricing is primarily focused on recovery of costs from beneficiaries, so the cost of System Restart Service should be borne by loads

Recommendation: The appropriate billing attributes would be a combination of Grid MWh and IRCR for each market customer (the same approach as for the allocation of Market Service costs)

NCESS (Voltage Control and Transient and Oscillatory Stability)

- ESS associated with voltage control and transient and oscillatory stability provide for the transmission network to operate at higher capacity (in a similar manner to raising thermal transmission limits)
  - Procured services to assist in these matters include generator operation to provide voltage support or increased stability.
- The causers of such services are loads requiring power to be supplied and generators providing the power, including any transmission issues that require such services
  - These services are often provided under network support contracts with the network operator, which may be a substitute for network investments
- It is appropriate to recover these costs from loads (beneficiaries), given that the focus of this charge is typically cost recovery, not market efficiency
- As these services are a substitute for network investments, it may also be appropriate for network operators to recover these costs via network access charges

Recommendation:
– if Western Power procures the NCESS, the cost should be recovered via network tariffs
– if AEMO procures the NCESS, the costs should be recovered from loads via retailers (combination of Grid MWh and IRCR MW)

Next Steps

Next Steps

- Provide update for the MAC on progress by 8 November for discussion at 11 November 2022 MAC meeting
- Develop cost allocation methodologies, accounting for feedback from the CARWG and MAC
- Draft consultation paper
    - Updated paper to MAC on 6 December 2022 for discussion at MAC meeting on 13 December 2022
    - Publish for consultation in December 2022 / February 2023

We're working for Western Australia.