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Cost Allocation Review

Consultation Paper

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Working together for a brighter energy future.

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

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

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

Enquiries about this report should be directed to:

Email: energymarkets@dmirs.wa.gov.au

Contents

Glossary 6

Executive Summary 8

1. Introduction 15

1.1 Background 15

1.2 Fees and Charges in Scope 15

1.3 Out of Scope 16

1.4 Purpose of this Paper 16

1.5 Call for Submissions 17

2. Approach to the Review 18

2.1 Approach to Qualitative Assessment – Guiding Principles 18

2.2 Approach to Quantitative Assessment – Modelling 18

3. Market Fees 19

3.1 Description of the Market Fees 19

3.2 Qualitative Assessment 19

3.2.1 Who should pay Market Fees? 19

3.2.2 Is allocating Market Fees based on Grid MWh Equitable? 21

3.2.3 Assessment of the Current Market Fee Allocation Method 22

3.2.4 Options for Cost Recovery 22

3.3 Impact of Fee Allocation Options on Market Participants 24

3.4 Treatment of Energy Storage Facilities 26

3.5 Costs and Priority of Implementing the WEM Hybrid Method 27

3.6 Views of the CARWG and MAC 27

3.7 Recommendation 28

4. Essential System Services 29

4.1 Description of Services 29

4.2 Future Frequency Regulation and Contingency Reserve Raise and Lower Requirements 30

5. Regulation Raise and Lower 34

5.1 Description of the Service 34

5.2 Options Identified 35

5.2.1 The Current NEM Causer-Pays Method 35

5.2.2 The Forecast Range Method 36

5.2.3 The New NEM Causer-Pays Method 39

5.3 Benefits of the Alternative Approaches 41

5.4 Concerns with Alternative Approaches 41

5.4.1 The New NEM Causer-Pays Method 41

5.4.2 The Forecast Range Method 42

5.4.3 Multiple Objectives of Alternative Methods 42

5.5 The WEM Deviation Method (Simplified Causer-Pays) 43

5.5.1 Assessment of the WEM Deviation Method 44

5.6 Proposed Allocation Method 45

6. Contingency Reserve Raise 47
7. Contingency Reserve Lower 50
7.1 Current Cost Recovery Approach 50
7.2 Contingency Reserve Lower Service Requirements 50
7.3 Cost Recovery Scenarios with entry of large loads in the WEM 51
7.3.1 Load Cost Allocation with Runway Method 51
7.3.2 Adjusting Load Cost Allocation with Runway Method for Network Contingencies 53
7.3.3 Recommendation for Cost Allocation for Contingency Reserve Lower Service Requirements 56
8. Other Essential System Services 57
8.1 RoCoF 57
8.2 System Restart 57
8.3 NCESS 57

Tables

Table 1: Market Fees 19
Table 2: Assessment of Market Fee Options 23
Table 3: Indicative Impact of AEMO Market Fees on Market Participants by Type 25
Table 4: Cost Allocation by Cost Recovery Method and Generator 25
Table 5: Pros and Cons of Proposed WEM Deviation Method 44
Table 6: Example of Current Cost Recovery Method for Contingency Reserve Lower Costs 51
Table 7: Modified Runway Method for Allocating Contingency Reserve Lower Costs – Single Battery Case 52
Table 8: Modified Runway Method for Allocating Contingency Reserve Lower Costs – Two Battery Case 53
Table 9: Modified Runway Method for Allocating Contingency Reserve Costs – Single Battery Case with Highest Network Risk 55

Figures

Figure 1: Ancillary Service Costs in the WEM 29
Figure 2: ESS Costs by Service Type ($ per MW per trading interval) 30
Figure 3: Capacity in the SWIS Scenario 31
Figure 4: Frequency Regulation Requirements (MW) 32
Figure 5: Annual LFAS Costs (June 2022 dollars) 32
Figure 6: Frequency Regulation Cost Allocation Share – Current WEM Method 34
Figure 7: Frequency Control Cost Recovery in the WEM using Current NEM Causer-Pays Contribution Factors 36
Figure 8: Using Forecast Range for Frequency Regulation Cost Recovery 37
Figure 9: Solar Farm Providing Regulation Raise 38
Figure 10: Frequency Regulation Cost Recovery Factors (%) for WEM under the Current NEM Causer-Pays and Forecast Range Method 38

Figure 11: Frequency Regulation Cost Recovery Factors for the WEM under the NEM Causer-Pays (Existing and New) and Forecast Range Methods 40
Figure 12: Frequency Regulation Cost Recovery Factors (%) for the WEM under the New NEM Causer-Pays Method 40
Figure 13: WEM Deviation Method Calculation 43
Figure 14: Contribution Factors for the WEM Deviation Method and Other Methods 44

Glossary

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

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

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

Executive Summary

Cost Allocation Review

As part of the Energy Transformation Strategy, the Energy Transformation Taskforce (Taskforce) implemented substantial changes to the design of the Wholesale Electricity Market (WEM). While some stakeholders identified issues with the allocation of Market Fees and Essential System Services (ESS) costs to Market Participants during the reform process, the Taskforce was unable to address all of these concerns in the time available.

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

The WEM Rules confers the function on the Coordinator of Energy (Coordinator) to consider and, in consultation with the Market Advisory Committee (MAC), progress the evolution and development of the WEM and the WEM Rules. In line with this function, the Coordinator commenced a Cost Allocation Review in 2022, of the allocation of Market Fees and ESS costs.

The Coordinator has consulted with the MAC, and the Cost Allocation Review Working Group (CARWG) established by the MAC, throughout the progression of the review. The Cost Allocation Review has now reached some preliminary conclusions and developed recommendations for changes to the cost allocation methods, where relevant.

Approach to the Review and this Consultation Paper

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

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

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

This Consultation Paper:

- presents a qualitative assessment of whether the current cost allocation methods are aligned with the guiding principles;
- where the cost allocation methods are not aligned with the guiding principles, proposes changes or new methods that are more consistent with the guiding principles; and
- presents a quantitative assessment of the impact of the proposed changes on Market Participants, in comparison to the status quo.

This Consultation Paper sets out the outcomes from the first three stages of the Cost Allocation Review, which involved policy assessment, practicality assessment and methodology development, where relevant. The Coordinator is seeking feedback on 6 recommendations regarding the methodologies to allocate Market Fees and ESS costs to Market Participants.

A summary of the analysis is outlined below, with proposals highlighted for each of the six components of the cost allocation framework.

The final stage of the Cost Allocation Review will involve the publication of an Information Paper, and consultation on draft Amending WEM Rules to implement any changes.

Market Fees

Under the WEM Rules, Market Fees are applied to Market Participants to recover costs for a range of market services including:

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

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

EPWA, in consultation with the CARWG, conducted a qualitative assessment of the Market Fee allocation method made some observations in response to the following key questions:

1. Who should be charged Market Fees to recover the costs of market services:
   - Both Market Generators and Market Customers can be regarded as a "causer" and "beneficiary" of market services, which provides justification for levying charges on both Market Generators and Market Customers.
   - Guidance on who should bear these costs can be obtained by considering the purpose of levying Market Fees:
     - If the primary purpose is market efficiency, then this is about sending a signal for participants to optimise their use of the relevant market services. However, Market Fees contribute only about 0.5% of the total cost of electricity, so changing the Market Fee allocation method is unlikely to incentivise Market Participants to change their use of market services.
     - If the primary purpose is cost recovery, then the focus should be on ensuring efficient recovery of the relevant costs. It may be less efficient to charge Market Fees to generators (and network operators) because these fees will need to be passed through to retailers under their wholesale supply agreements (or included in network access agreements if levied on network operators). However, as cost allocation arrangements are already in place, any efficiency gains are likely to be offset by the cost of implementing alternative arrangements.
2. Is the current use of Grid MWh[1] as the basis for charging Market Fees equitable:
   - Levying Market Fees on metered generation or loads (Grid MWh) means that the level of cost recovery is proportional to energy generated or consumed, which may result in inequities because:

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

- a Market Customer whose portfolio has significant installed behind-the-meter (BTM) PV will pay relatively less Market Fees than one with little BTM PV, but the cost of providing market services to Market Customers will likely be the same irrespective of the level of BTM PV in their portfolio; and
- a Market Generator whose portfolio has a low capacity factor will pay relatively less Market Fees than one with high capacity factor, but the cost of providing market services to Market Generators will likely be the same irrespective of capacity factor.

3. Assessment against the guiding principles

- While the current method to allocate the costs for market services is consistent with the principles of cost effectiveness, simplicity and practicality, it is likely to result in some inequities.
- The currently method may favour Market Customers with particular types of end customers and particular generators over others, as indicated above.

A range of options were considered to overcome some of these potential shortcomings – see Section 3.2.

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

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

Proposal 1 – Market Fees

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

Frequency Regulation

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

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

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

Given the relatively low proportion of VRE plant in the SWIS compared to Non-Dispatchable loads, 90% of Frequency Regulation costs are currently recovered from loads, but this will change as VRE plant penetration increases.

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

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

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

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

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

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

Proposal 2 – Frequency Regulation

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

Contingency Reserve Raise

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

However, to ensure consistency with the causer-pays principle, the Facility Risk Value used in the current runway method for cost allocation should be amended to take into account the reduced risks associated with a Facility comprised of multiple units, which has a number of network connections.

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

Proposal 3 – Contingency Reserve Raise
Application of the runway method should be adjusted to cater for situations, in which a Facility is comprised of multiple units each with a separate network connection. In this situation, each unit should be treated separately in the runway method (i.e., they should have separate Facility MW for the purposes of Contingency Reserve Raises cost recovery).

Contingency Reserve Lower

Contingency Reserve Lower is required to cover the risk of a material increase in system frequency due to a loss of single large load, or multiple loads on a single network element. The requirement for Contingency Reserve Lower services is a function of the size of the load that may be lost, which is analogous to the loss of the largest generator being the primary causer of Contingency Reserve Raise requirements.

A modified runway method could be applied to allocate Contingency Reserve Lower costs to the largest loads operating in a trading interval – this would be consistent with the causer-pays principle and with how Contingency Reserve Raise costs are recovered.

This will be important given the potential for large BESS and hydrogen electrolysers connecting to the SWIS. Connecting large loads to the system could substantially increase the Contingency Reserve Lower requirements and these loads should bear the additional costs associated with the increased Contingency Reserve Lower requirements.

A modified runway method to allocate Contingency Reserve Lower costs would meet the causer-pays principle and may provide developers with an incentive to reduce the size of the loads they connect to the SWIS to reduce their exposure to these costs, resulting in an efficient market outcome.

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

Proposal 4 – Contingency Reserve Lower

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

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

(1) Load Contingency Reserve Lower cost allocation:

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

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

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

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

Other ESS

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

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

Proposal 5 – System Restart Services

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

Non-Co-Optimised ESS (NCESS) can be either non-network locational services procured by Western Power to substitute for network upgrades or services procured by AEMO.

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

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

Proposal 6 – NCESS

Recovery of NCESS should occur as follows:

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

Call for Submissions

Stakeholder feedback is invited on the preliminary conclusions and the proposed changes, where relevant, to the cost allocation methods presented in this consultation paper.

Submissions can be emailed to energymarkets@dmirs.wa.gov.au. Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00 pm WST on Thursday 9 February 2023. Late submissions may not be considered.

1. Introduction

1.1 Background

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

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

Clause 2.2D.1 of the WEM Rules confers the function on the Coordinator to consider and, in consultation with the MAC, progress the evolution and development of the WEM and the WEM Rules. The Coordinator commenced the Cost Allocation Review to review the allocation of Market Fees and ESS costs, in consultation with the MAC.

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

The Cost Allocation Review is being conducted in four steps:

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

The Cost Allocation Review has made some preliminary findings and developed proposals for changes to the cost allocation methods, where relevant, and the purpose of this paper is to seek feedback from stakeholders on the findings and proposals.

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

1.2 Fees and Charges in Scope

The fees and charges that are in scope for the Cost Allocation Review include Market Fees and the costs for both co-optimised ESS and other types of ESS. More detail on the relevant fees and costs is provided below.

Market Fees

The Market Fees assessed under this review include:

- Market Fees to recover AEMO's costs for its market operation services, system planning services and market administration services;
- System Operation Fees to recover AEMO's costs for its system operation services;
- Regulator Fees to recover the Economic Regulation Authority's (ERA) costs for its monitoring, compliance, enforcement and regulation services, and

- Coordinator Fees to recover the Coordinator's costs for its functions under the WEM Rules plus the costs and expenses for the Chair of the MAC.

Co-optimised ESS Costs

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

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

Other ESS Costs

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

1.3 Out of Scope

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

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

1.4 Purpose of this Paper

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

The Coordinator will consider responses to this consultation paper in developing an information paper that will conclude the review of the allocation of Market Fees and ESS costs to Market Participants. Amending WEM Rules will be drafted, for consultation, based on the policy decisions outlined in the information paper.

This Consultation Paper is structured as follows:

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

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

In parallel with this paper, Energy Policy WA (EPWA) is publishing a paper that reviews the cost allocation methodologies used in international energy markets.

1.5 Call for Submissions

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

Submissions can be emailed to energymarkets@dmirs.wa.gov.au. Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00 pm WST on 9 February 2023. Late submissions may not be considered.

2. Approach to the Review

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

2.1 Approach to Qualitative Assessment – Guiding Principles

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

1. Meet the Wholesale Market Objectives;[2]
2. Be cost-effective, simple, flexible, sustainable, practical, and fair;
3. Provide effective incentives to Market Participants to operate efficiently to minimise the overall cost to consumers; and
4. Use the causer-pays principle, where practicable and efficient.

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

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

2.2 Approach to Quantitative Assessment – Modelling

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

[2] The Wholesale Market Objectives are:

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

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

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

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

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

3. Market Fees

3.1 Description of the Market Fees

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

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

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

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

Table 1: Market Fees

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

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

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

3.2 Qualitative Assessment

3.2.1 Who should pay Market Fees?

The cost of market services does not vary significantly with sent out generation and/or load, or the number of Market Participants. Many of these costs are fixed and are determined by factors

3 Calculated by Marsden Jacob 2022.

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

outside of the control of retailers and generators. As outlined in the international review,[5] costs for market services are primarily a function of the market design and maturity (e.g. number and type of participants, market complexity, etc).

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

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

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

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

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

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

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

- If efficiency is the primary concern for the allocating Market Fees, then the fees should send an effective signal for a Market Participant to optimise their use of the market services provided by AEMO, the Coordinator and the ERA. This approach is unlikely to change the use of the market services given that these fees are significantly lower than other costs, and that Market Participants often have no choice but to use the services of AEMO, the Coordinator and the ERA.
- If efficiency is not the primary concern, then the primary purpose of the fees is cost recovery. Ofgem (UK) makes the following observation:

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

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

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

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

The Second BSUoS Taskforce provided further rationale for this decision:

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

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

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

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

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

3.2.2 Is allocating Market Fees based on Grid MWh Equitable?

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

- A Market Generator with a portfolio of peaking and mid-merit plant with relatively low capacity factors (<30%) will pay less than a Market Generator with base load generation (capacity factor ≥ 50%). However, it is unlikely that the costs of AEMO, the Coordinator or the ERA will vary with the type of generator installed or the capacity factor of each generation type. To overcome this inequity, the NEM uses a combination of Grid MWh and Sent Out Capacity (MW) to recover costs from Market Generators.
- Market Customers are allocated Market Fees on a Grid MWh basis which, if passed on to final customers, may add to an incentive for energy efficiency or the installation of DER. This may create an inequity between Market Customers depending on whether their final consumers have DER. To overcome this inequity, the NEM uses a combination of Grid MWh and the number of connection points (or NMIs) to ensure a more equitable level of cost recovery across different types of final customers.

To address the inequity between large and small end customers, and end customers that have low grid consumption due to DER, some jurisdictions have considered using gross MWh (or MW) as

7 BSUoS charges includes ancillary services and Market Fees.

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

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

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

3.2.3 Assessment of the Current Market Fee Allocation Method

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

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

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

3.2.4 Options for Cost Recovery

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

Table 2: Assessment of Market Fee Options

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

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

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

Source: Marsden Jacob 2022

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

3.3 Impact of Fee Allocation Options on Market Participants

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

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

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

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

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

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

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

Table 4: Cost Allocation by Cost Recovery Method and Generator

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

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

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

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

Source: Marsden Jacob 2022

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

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

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

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

3.4 Treatment of Energy Storage Facilities

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

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

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

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

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

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

3.5 Costs and Priority of Implementing the WEM Hybrid Method

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

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

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

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

3.6 Views of the CARWG and MAC

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

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

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

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

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

3.7 Recommendation

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

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

Proposal 1: Market Fees

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

Consultation Question 1:

Do stakeholders support:

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

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

17 Minutes from the CARWG meeting on 27 September 2022.

18 Ibid.

4. Essential System Services

4.1 Description of Services

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

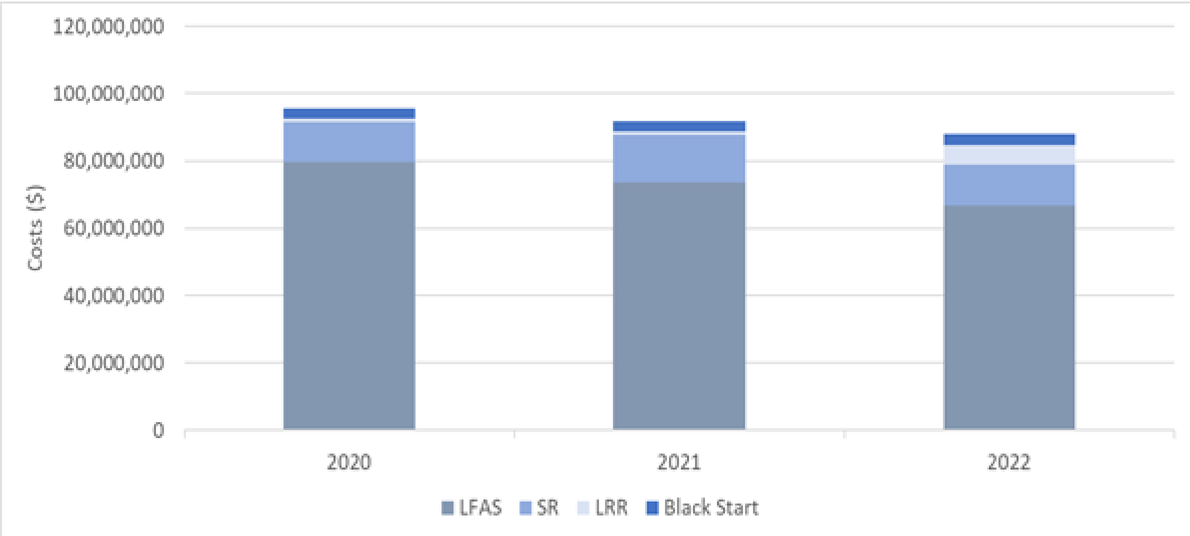
- Regulation Raise (currently referred to as Load Following Ancillary Services (LFAS) Up);
- Regulation Lower (currently referred to as LFAS Down);
- Contingency Reserve Raise (currently referred to as Spinning Reserve Ancillary Service or SRAS);
- Contingency Reserve Lower (currently referred to as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

Non-Co-optimised ESS includes:

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

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

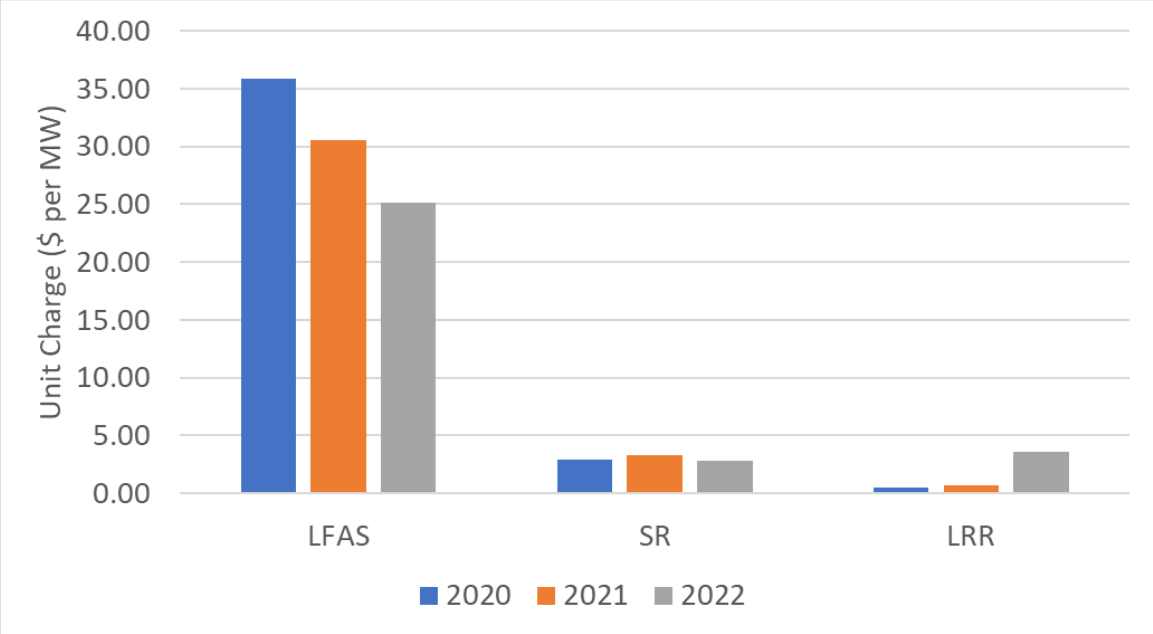
Figure 1: Ancillary Service Costs in the WEM



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

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

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



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

4.2 Future Frequency Regulation and Contingency Reserve Raise and Lower Requirements

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

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

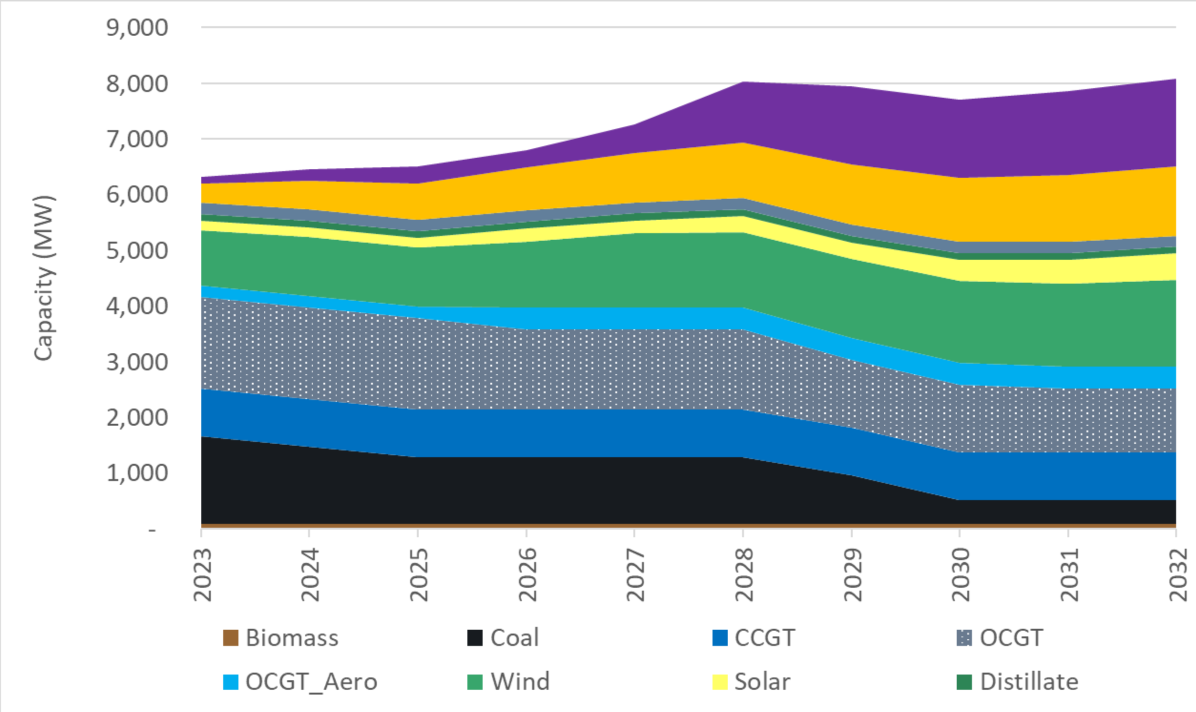
The key features of Marsden Jacob's scenario are:

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

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

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

Figure 3: Capacity in the SWIS Scenario



Source: Marsden Jacob 2022

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

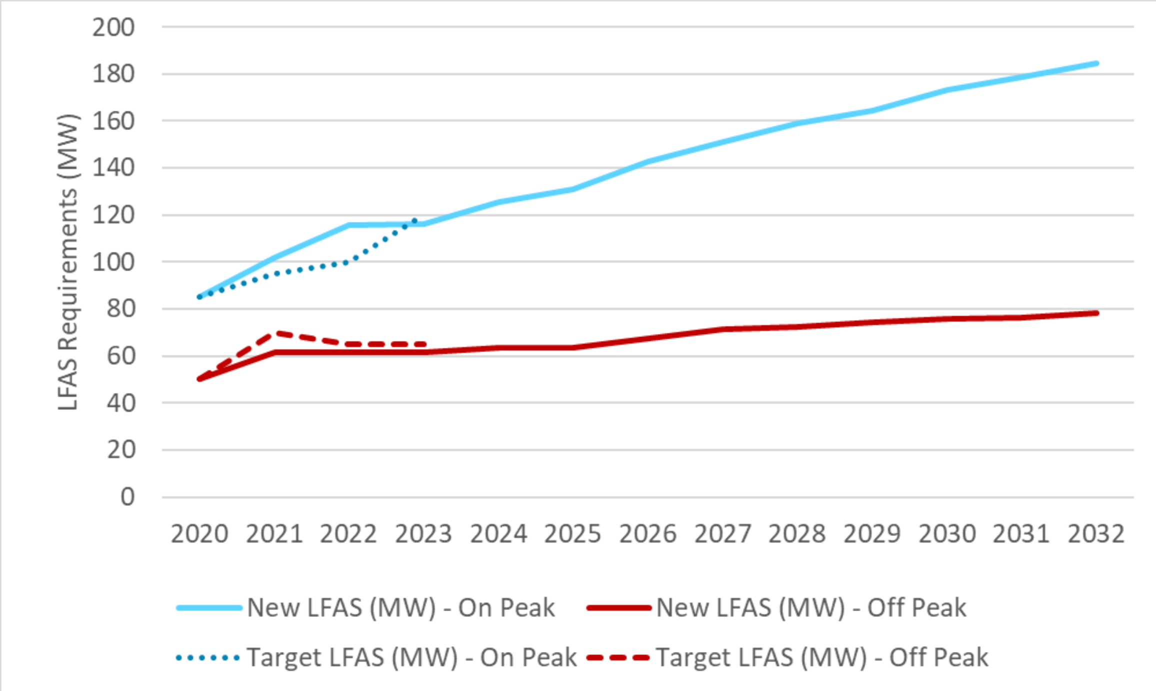
- grid connected storage increases from 110 MW in 2022/23 to 1,575 MW in 2031/32;
- wind generation increases from 997 MW to 1558 MW; and
- large-scale solar increases from 168 MW to 471 MW.

Under this scenario:

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

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

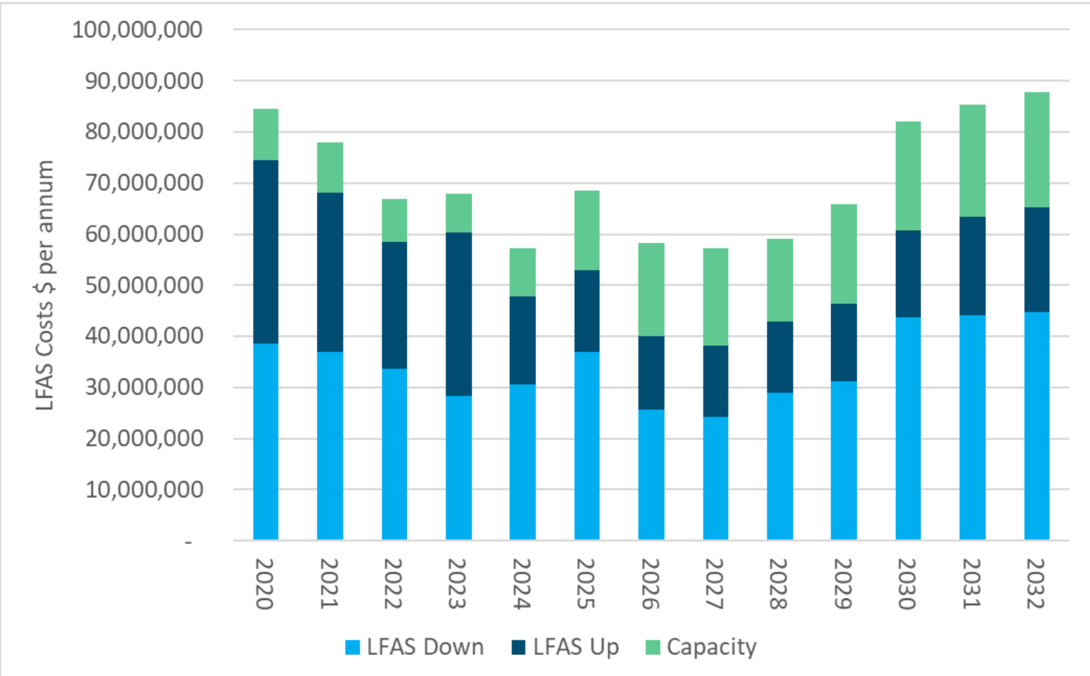
Figure 4: Frequency Regulation Requirements (MW)



Source: Marsden Jacob 2022

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

Figure 5: Annual LFAS Costs (June 2022 dollars)



Source: Marsden Jacob 2022

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

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

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

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

5. Regulation Raise and Lower

5.1 Description of the Service

The need for Frequency Regulation can arise due to:

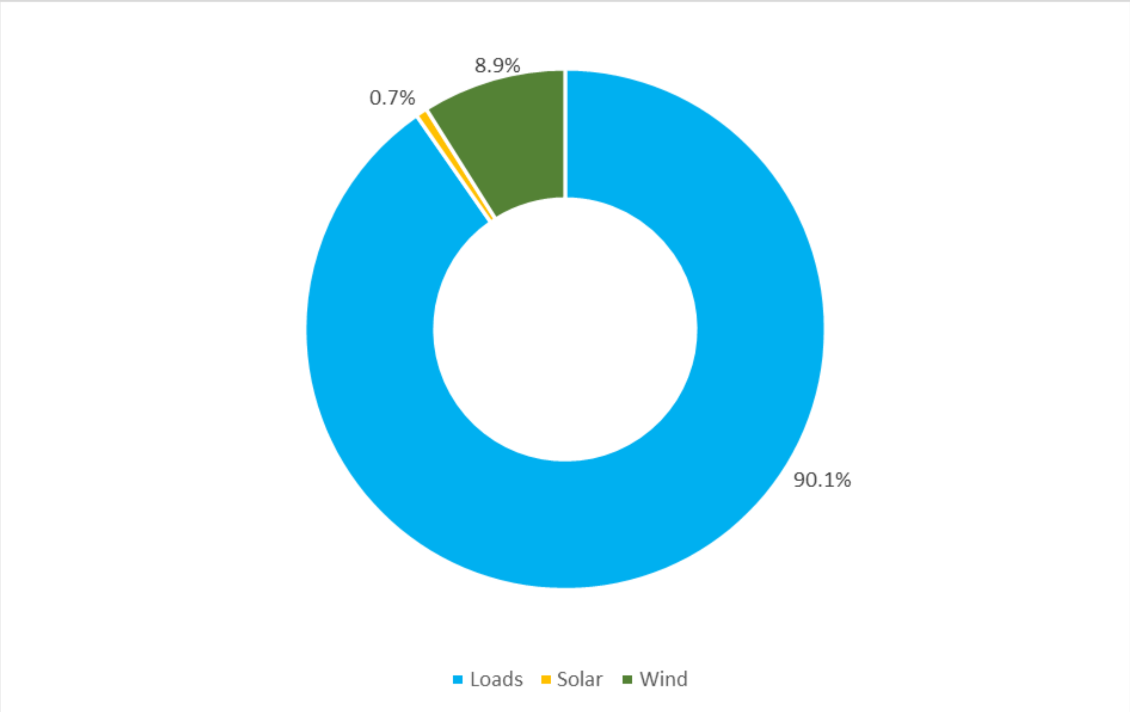
- deviations between actual and forecast generation from intermittent generation sources;
- scheduled generators and scheduled loads deviating from dispatch targets, other than in response to a frequency deviation;
- differences between aggregated customer load profiles and generator ramping profiles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

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

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

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

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



Source: Marsden Jacob 2022

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

5.2 Options Identified

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

5.2.1 The Current NEM Causer-Pays Method

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

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

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

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

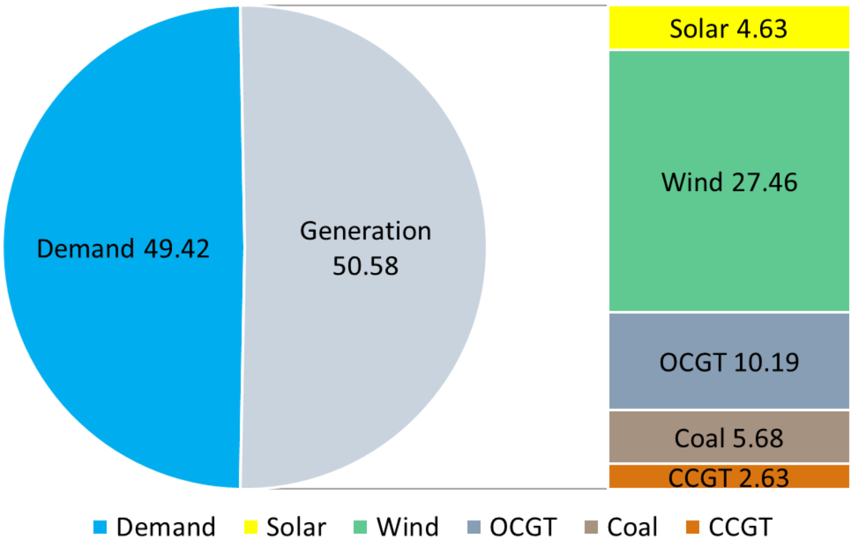
The purpose of these Contribution Factors is to attribute costs to parties that are responsible for frequency deviations and to provide incentives for them to change their behaviour to reduce Regulation FCAS costs. Such changes could include investment in better forecasting systems, co-locating storage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

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

Quantitative Assessment of the Current NEM Causer-Pays Method

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

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



Source: Marsden Jacob 2022

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

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

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

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

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

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

5.2.2 The Forecast Range Method

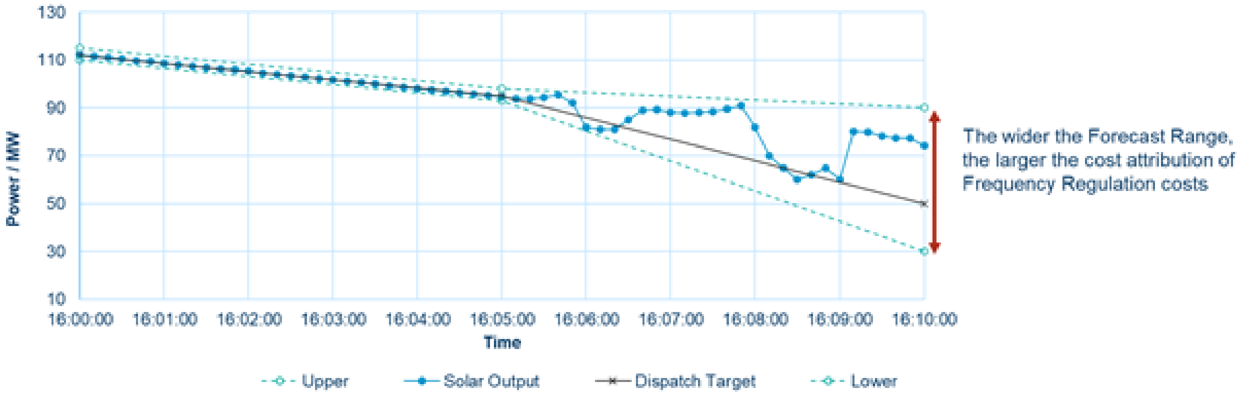
AEMO has suggested that ex-ante forecast ranges provided by Market Participants could be used to set the requirement for Regulation services and to allocate Regulation costs to Market Participants as an alternative to applying NEM Causer Pay factors.

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

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

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

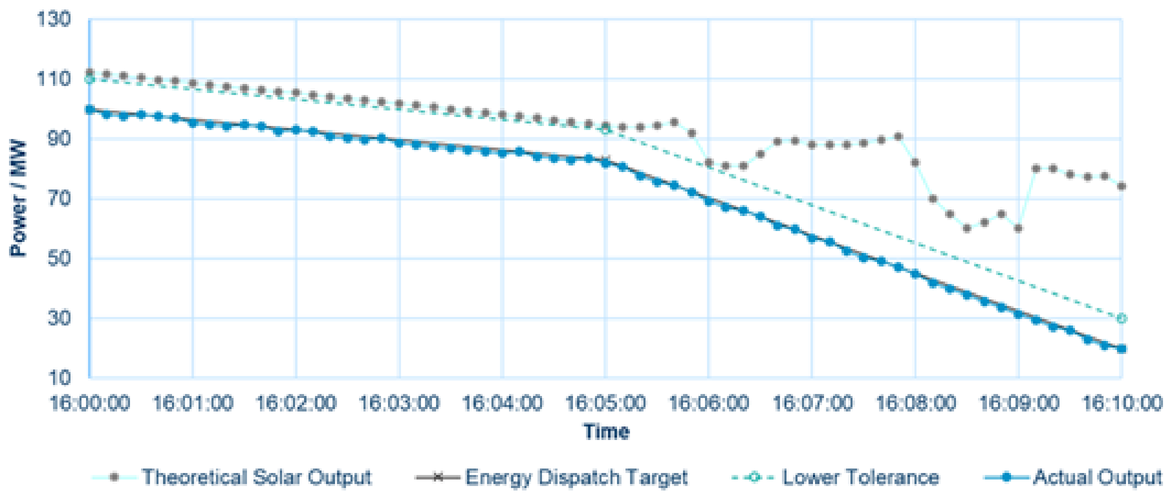
Figure 8: Using Forecast Range for Frequency Regulation Cost Recovery



Source: AEMO 2022

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

Figure 9: Solar Farm Providing Regulation Raise

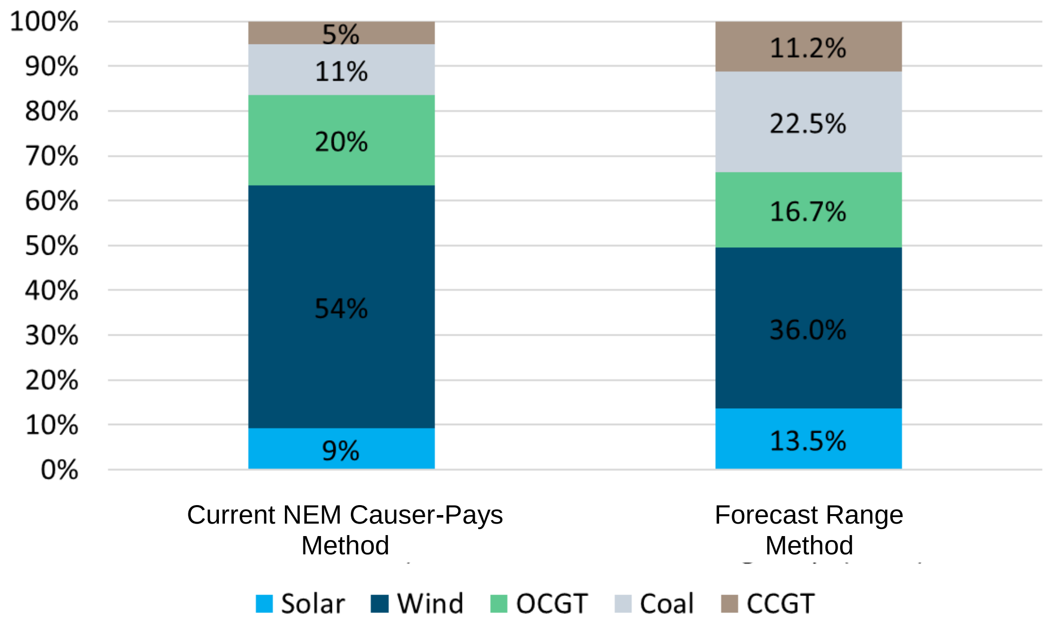


Source: AEMO 2022

Quantitative Assessment of the Forecast Range Method

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

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



Source: Marsden Jacob 2022

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

5.2.3 The New NEM Causer-Pays Method

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

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

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

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

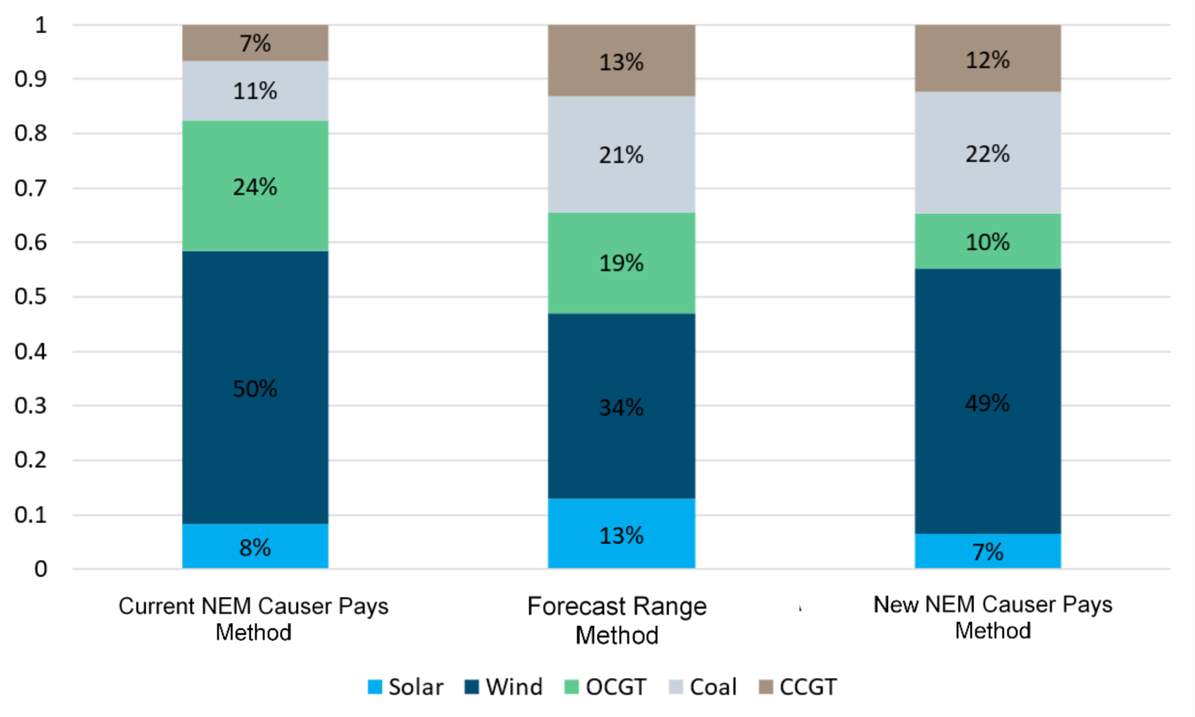
AEMO is continuing to develop the approach to implementing the New Causer-Pays Method in the NEM for commencement on 8 June 2025.

Quantitative Assessment of New NEM Causer-Pays Method

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

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

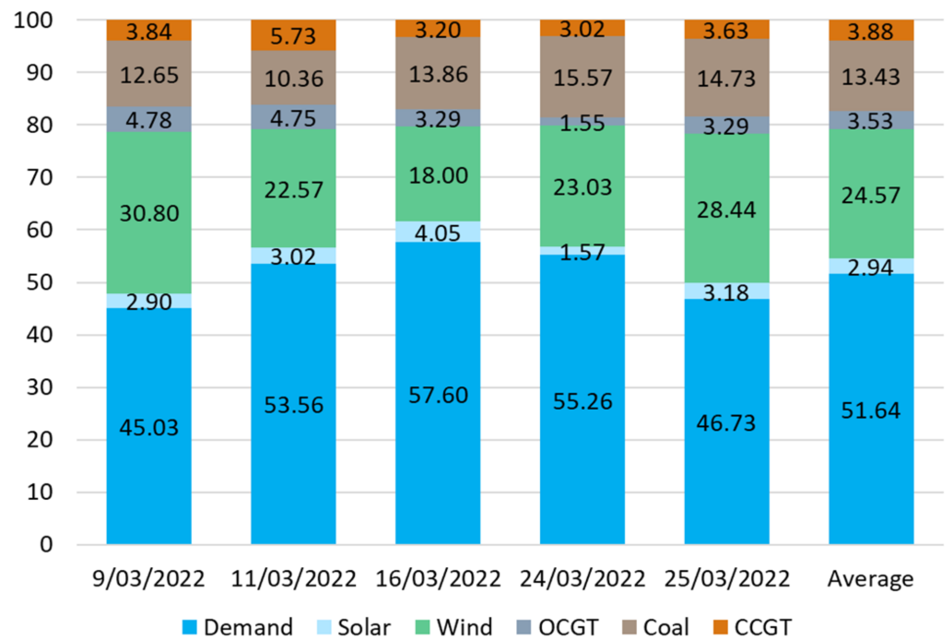
Figure 11: Frequency Regulation Cost Recovery Factors for the WEM under the NEM Causer-Pays (Existing and New) and Forecast Range Methods



Source: Marsden Jacob 2022

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

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



Source: Marsden Jacob 2022

5.3 Benefits of the Alternative Approaches

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

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

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

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

5.4 Concerns with Alternative Approaches

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

5.4.1 The New NEM Causer-Pays Method

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

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

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

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

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

5.4.2 The Forecast Range Method

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

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

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

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

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

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

5.4.3 Multiple Objectives of Alternative Methods

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

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

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

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

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

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

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

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

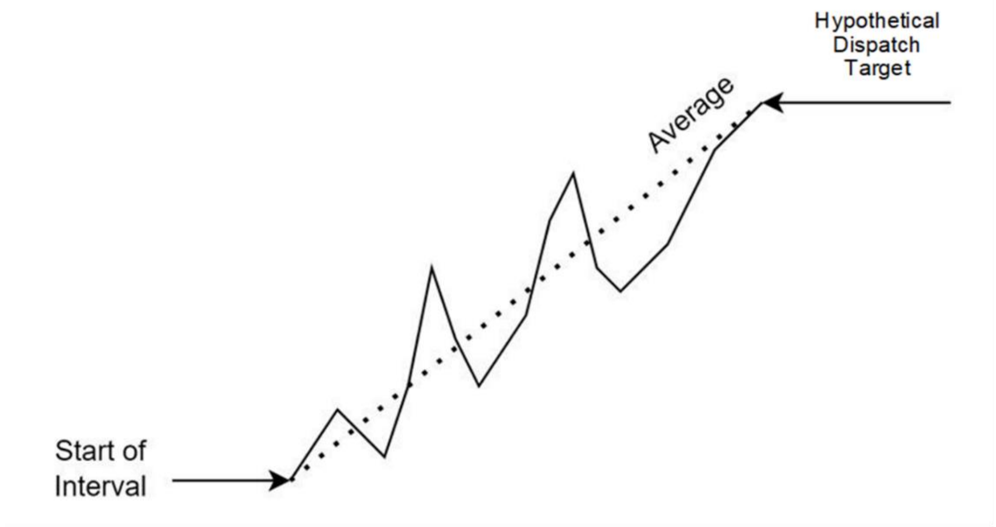
5.5 The WEM Deviation Method (Simplified Causer-Pays)

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

This would involve:

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

Figure 13: WEM Deviation Method Calculation



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

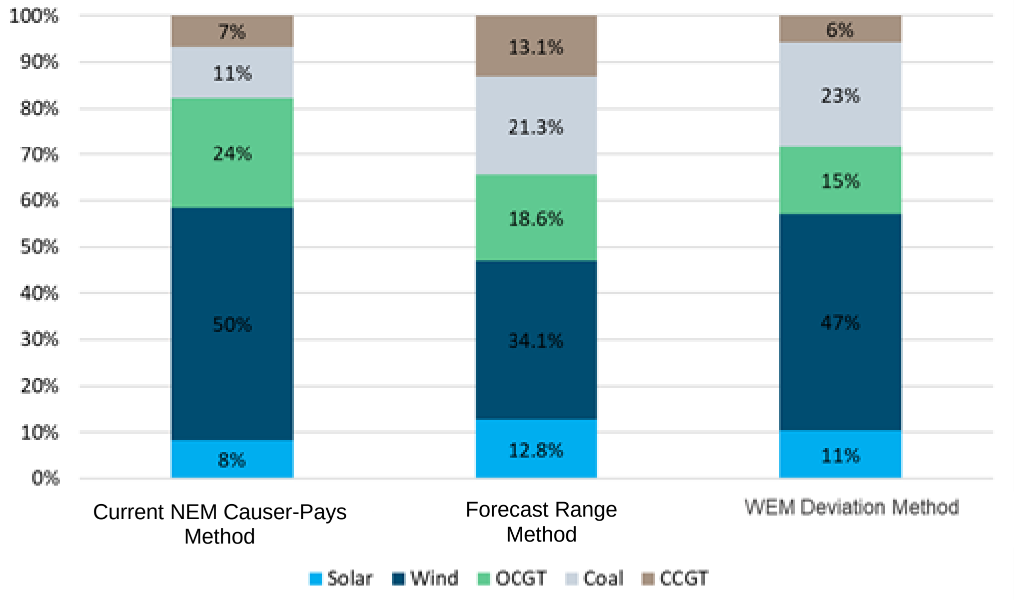
5.5.1 Assessment of the WEM Deviation Method

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

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

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

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



Source: Marsden Jacob 2022

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

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

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

Table 5: Pros and Cons of Proposed WEM Deviation Method

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

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

5.6 Proposed Allocation Method

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

The WEM Deviation Method is preferred because:

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

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

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

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

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

Proposal 2: Regulation Raise and Lower

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

Consultation Question 2:

Do stakeholders support:

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

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

6. Contingency Reserve Raise

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

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

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

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

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

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

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

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

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

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

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

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

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

Other configurations are possible, such as in the case of the Collgar Wind Farm. The total installed capacity of the wind farm is 218.5 MW, but it comprises two sets of controllable inverters (109 MW), each with their own separate network connection. Because the Facility is currently registered as a single Facility, its maximum FacilityMW will be 218.5 MW. However, the largest credible supply contingency for this Facility is only likely to be 109 MW (i.e., electrical failure for a single set of inverters, or failure at the network connection).

For the purposes of applying the runway method for Contingency Reserve Raise cost allocation, basing the maximum FacilityMW on the capacity of the independently controlled set of inverters, each with its own separate network connection, may be a more appropriate way to define FacilityMW for the Collgar Wind Farm.

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

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

Typically, Contingency Reserve Raise requirements are 200-250 MW, so permitting Market Participants to aggregate facilities and, as a result, increasing Contingency Reserve Raise services to 417 MW, in this example, would be a significant increase in requirements.

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

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

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

For the purposes of the runway method, the maximum FacilityMW that is used to determine a Facility's Risk Value:

- for a single Facility with a single unit, should be equal to the maximum capacity of the single unit;
- for a single Facility with multiple units each with a separate network connection, each unit should be treated separately (e.g. the Collgar Wind Farm should be treated as two 109 MW units under the runway method rather than a single unit); and
- for an Aggregated Facilities (comprising two or more units each with a separate network connection), should be determined for each separate unit.

Proposal 3: Contingency Reserve Raise

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

Consultation Question 3:

Do stakeholders support treating separately the units in a Facility for the purpose of calculating the Facility's Contingency Reserve Raise costs, if each of these units have separate network connections?

7. Contingency Reserve Lower

7.1 Current Cost Recovery Approach

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

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

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

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

7.2 Contingency Reserve Lower Service Requirements

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

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

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

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

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

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

7.3 Cost Recovery Scenarios with entry of large loads in the WEM

7.3.1 Load Cost Allocation with Runway Method

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

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

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

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

Source: Marsden Jacob 2022

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

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

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

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

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

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

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

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

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

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

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

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

Source: Marsden Jacob 2022

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

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

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

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

Source: Marsden Jacob 2022

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

- ensure that new large loads exceeding 120 MW would pay for the higher Contingency Reserve Lower requirement that they cause when operating; and
- provides developers with an incentive to reduce the size of their largest load connected to the SWIS to reduce their exposure to the Contingency Reserve Lower costs, resulting in a more efficient market outcome.

7.3.2 Adjusting Load Cost Allocation with Runway Method for Network Contingencies

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

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

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

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

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

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

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

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

Consider a hypothetical example:

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

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

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

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

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

Source: Marsden Jacob 2022

In summary:

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

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

7.3.3 Recommendation for Cost Allocation for Contingency Reserve Lower Service Requirements

Proposal 4: Contingency Reserve Lower

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

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

(1) Load Contingency Reserve Lower cost allocation:

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

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

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

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

Consultation Question 4:

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

8. Other Essential System Services

8.1 RoCoF

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

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

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

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

8.2 System Restart

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

Proposal 5: System Restart

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

Consultation Question 5:

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

8.3 NCESS

NCESS can be either locational services procured by Western Power or services procured by AEMO to respond to unforeseen events in the power system to enable the maintenance of security and reliability at the lowest cost.

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

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

Proposal 6: NCESS

Recovery of NCESS should occur as follows:

- where AEMO procures the NCESS, the NCESS costs should be allocated to beneficiaries of the services (Market Customers), given that the current focus of NCESS charges is cost recovery and not market efficiency; and

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

Consultation Question 6:

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

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

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