Government of **Western Australia**
Energy Policy WA

Scope of Work for the Review of the Allocation of Market Fees and Essential System Services Costs

1. Introduction

1.1 Review Requirements

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

Further, the Market Advisory Committee (**MAC**) maintains a Market Development Forward Work Program to track and progress issues that have been identified by stakeholders. Several issues on the current Market Development Forward Work Program relate to the allocation of market costs – see Appendix 1.

Therefore, the Coordinator of Energy (**Coordinator**) plans to undertake a review of the allocation of Market Fees and ESS costs (**Cost Allocation Review**).

The Coordinator plans to conduct the Cost Allocation Review under clause 2.2D.1 of the Wholesale Electricity Market (**WEM**) Rules in 2022 and to develop any WEM Rules resulting from the review in 2023. Clause 2.2D.1(h) 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.

1.2 Background

1.2.1 Energy Transformation Strategy

Amending Rules were developed under the ETS to change how the costs of ESS are allocated. These Amending Rules will commence on 1 October 2023.

The Energy Transformation Taskforce undertook extensive consultation on the allocation of ESS costs, including via the ‘Market settlement: Implementation of five-minute settlement, uplift payments and Essential System Services settlement’ paper, published on 1 December 2019.[1]

1.2.2 Allocation of Market Fees

The following fees are specified in the WEM Rules:

- 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;

[1] https://www.wa.gov.au/system/files/2019-12/Information%20paper%20-%20Market%20Settlement%20-%20Implementation%20of%20five-minute%20settlement%2C%20uplift%20payments%20and%20ESS%20settlement%20-%20December%202019.pdf

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

AEMO determines and publishes the Market Fee, System Operation Fee, Regulator Fee and Coordinator Fee rates, which are set to cover the budgeted costs for AEMO, the ERA and the Coordinator, plus any under/over-spend from the previous year.

Each Market Participant is charged these fees based on the Market Fee, System Operation Fee, Regulator Fee and Coordinator Fee rates and their Metered Schedule[2] for all of their Registered Facilities and Non-Dispatchable Loads for all Trading Intervals for the day.

AEMO also charges Application Fees and Reassessment Fees, which are set to recover the average costs of processing each type of application.

1.2.3 Allocation of 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.

The Table in Appendix 2 indicates how the costs for each co-optimised ESS will be allocated as of 1 October 2023, including:

- the risks that will be covered by each ESS;
- a description of each ESS; and
- an indication of how the costs for each ESS will be allocated.

1.2.4 Allocation of Other ESS Costs

Other ESS include:

- System Restart Service; and
- Non-Co-optimised ESS (**NCESS**).

Costs for System Restart Services are determined by contracts between AEMO and service providers, and the contract costs are recovered from Market Participants based on the proportion of their Loads' metered consumption to total consumption.

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2 The Metered Schedule is determined for each Facilitythe net quantity of energy generated and sent-out or consumed by the Facility or Non-Dispatchable Load during the Trading Interval. A single Metered Schedule is determined for each Trading Interval for the Non-Dispatchable Loads without interval meters that are served by Synergy equal to the Notional Wholesale Meter.

The WEM Rules regarding NCESS are under development and will be Gazetted and implemented in early 2022. NCESS costs will be determined by contracts between AEMO or Western Power and service providers. Western Power will recover the costs for its NCESS contracts via its network tariffs,[3] and it is proposed that, at least initially, AEMO will recover costs for its NCESS contracts from Market Participants based on the proportion of their Loads' metered consumption to total consumption.

2. Project scope

2.1 Objectives

The objectives for the Cost Allocation Review are to:

(1) develop a method to align the allocation of fees with the causer-pays principle, to the extent practicable and efficient; and

(2) develop a method to align the allocation of ESS costs with the causer-pays principle, to the extent practicable and efficient.

2.2 Guiding principles

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

(1) Meet the Wholesale Market Objectives:

   (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.

(2) Be cost-effective, simple, flexible, sustainable, practical and fair.

(3) Provide effective incentives to Market Participants to operate efficiently to minimise the overall cost to consumers.

(4) Use the causer-pays principle, where practicable and efficient.

Where a causer can be identified for an ESS cost, the causer-pays principle would ensure that costs are allocated to parties in a way that gives the causer an incentive to manage their impact on that cost.

[3] Allocation of Western Power's NCESS costs is out of scope for the Cost Allocation Review.

2.3 Issues to be Considered

The Cost Allocation Review will consider the allocation of Market Fees and the aspects of the allocation of ESS costs that were not fully considered under the ETS. The matters that are to be considered in the review include:

(1) Does the current allocation of Market Fees provide an incentive to Market Participants to minimise the quantum of the fees, or would an alternative mechanism be better able to provide such an incentive?[4]

(2) Is the causer-pays principle adequately applied to the following ESS:

   (a) Regulation Services;

   (b) Contingency Reserve Raise Services;

   (c) Contingency Reserve Lower Services;

   (d) RoCoF Control Services;

   (e) System Restart; and

   (f) NCESS?

(3) Where the causer-pays principle is not applied adequately to allocation of ESS costs, how can cost allocation be improved to align more closely with that principle?[5]

The Cost Allocation Review will consider additional issues that are identified in consultation with the stakeholders, including the issues listed in Appendix 1.

2.4 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 (for example droop response);
- matters covered by the Reserve Capacity Mechanism Review (for example, changes to peak demand or reductions of load as a result of the Individual Reserve Capacity Requirement); and
- cost allocation matters recently considered by the Energy Transformation Taskforce that have resulted in recent 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.

3. Stakeholder engagement

The Cost Allocation Review will be undertaken in close consultation with the MAC and with the support of a dedicated MAC Working Group. Participation in the Working Group will not be limited to MAC members.

Under clause 2.5.1C of the WEM Rules, the Coordinator must consult with the MAC before commencing the development of a Rule Change Proposal.

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[4] For example, consideration could be given to charging Market Fees on a fixed and variable basis.

[5] For example, it could be argued that the costs for Regulation Services should be recovered from the causers of the frequency deviations, according to their contribution to the requirement for the service, including:

- for Non-Scheduled Facilities, according to their deviation from forecast;
- for Scheduled Facilities, according to their deviation from dispatch; and
- for Loads according to their volatility.

4. Project Schedule

Tasks/Milestones	Timing
Consult with the MAC on the scope of work for the review.	December 2021
Establish MAC Working Group.	January 2022
Engage consultant(s) to assist with the review.	January-March 2022
Initial MAC Working Group meeting	April 2022
Step 1 – Policy Assessment	
(a) Literature Review of the methodologies to allocate Market Fees and ESS costs in other jurisdictions.	April-June 2022
(b) In consultation with the MAC Working Group, assess whether, and to what extent, the current allocation method for the Market Fees and for the costs for each of the ESS are aligned with the causer-pays principle and, if not, whether they should be.	May-June 2022
Step 2 – Practicality Assessment	
(c) In consultation with the MAC Working Group, for the fees and costs that are not aligned, or not fully aligned, with the causer-pays principle: • identify the options that can be practically and efficiently applied in the WEM to allocate the Market Fees and each ESS cost; • assess each option against the guiding principles; • model the impact of each of the options on Market Participants; and • recommend a preferred option for the allocation of the Market Fees and each ESS cost.	July-August 2022
Step 3 – Methodology Development	
(d) Develop the details of the cost allocation methodologies, in consultation with the MAC Working Group.	September - October 2022
(e) Develop and publish a consultation paper on the design for the allocation methodologies and seek stakeholder comments.	November-January 2023
(f) Develop and publish an information paper on the detailed design for the allocation methodologies.	March 2023
Step 4 – Formal Rule Change	
(g) Develop one or more Rule Change Proposals for consideration by MAC, and approval by the Coordinator and Minister.	April 2023
(h) Commencement rule changes.	Depending on data availability and fit with the ETS reforms.

Appendix 1: Related Issues from the Market Development Forward Work Program

The following four issues from the Market Development Forward Work Program relate to the Cost Allocation Review.

Issue 2: Allocation of market costs – who bears Market Fees and who pays for grid support services with less grid generation and consumption?

Issue 16: BTM generation is treated as reduction in electricity demand rather than actual generation. Hence, the BTM generators are not paying their fair share of the network costs, Market Fees and ancillary services charges.

Therefore, the non-BTM Market Participants are subsiding the BTM generation in the WEM. Subsidy does not promote efficient economic outcome.

Rapid growth of BTM generation will only exacerbate this inefficiency if not promptly addressed.

Bluewaters recommends changes to the WEM Rules to require BTM generators to pay their fair share of the network costs, Market Fees and ancillary services charges.

This is an example of a regulatory arrangement becoming obsolete due to the emergence of new technologies. Regulatory design needs to keep up with changes in the industry landscape (including technological change) to ensure that the WEM continues to meet its objectives.

If this BTM issue is not promptly addressed, there will be distortion in investment signals, which will lead to an inappropriate generation facility mix in the WEM, hence compromising power system security and in turn not promoting the Wholesale Market Objectives.

Issue 23: Allocation of Market Fees on a 50/50 basis between generators and retailers may be overly simplistic and not consider the impacts on economic efficiency.

In particular, the costs associated with an electricity market reform program should be recovered from entities based on the benefit they receive from the reform. This is expected to increase the visibility of (and therefore incentivise) prudence and accountability when it comes to deciding the need and scope of the reform.

Recommendations: to review the Market Fees structure including the cost recovery mechanism for a reform program.

The cost saving from improved economic efficiency can be passed on to the end consumers, hence promoting the Wholesale Market Objectives.

Issue 35: BTM generation and apportionment of Market Fees, ancillary services, etc.

The amount of solar PV generation on the system is increasing every year, to the point where solar PV generation is the single biggest unit of generation on the SWIS. This category of generation has a significant impact on the system and we have seen this in terms of the daytime trough that is observed on the SWIS when the sun is shining. The issue is that generators that are on are moving around to meet the needs of this generation facility but this generation facility, which could impact system stability, does not pay its fair share of the costs of maintaining the system in a stable manner. That is, they are not the generators that receive its fair apportionment of Market Fees and pay any ancillary service costs but yet they have absolute freedom to generate into the SWIS when the fuel source is available. There needs to be equity in this equation.

Appendix 2: Allocation of Co-Optimised ESS

ESS	Risk	Service Description	Cost Allocation
Regulation Raise	Generation and load varying from target/forecast within the interval, leading to upward deviation from load forecast that causes the frequency to drop below 50 Hz.	Reserve MW to respond upwards during dispatch interval when load is greater than generation.	Allocated to Market Participants in proportion to their Regulation Contributing Quantity. The Regulation Contributing Quantity is essentially the sum of the absolute values of Metered Schedules for a Market Participant's Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads. Synergy's Notional Wholesale Meter is treated as a single Non-Dispatchable Load.
Regulation Lower	Generation and load varying from target/forecast within the interval, leading to downward deviation from load forecast during an interval that causes the frequency to go above 50 Hz.	Reserve MW to respond downwards when load is less than generation.	
Contingency Reserve Raise	Loss of generation.	Reserve MW to respond to loss of generation to restore frequency to an acceptable level.	Allocated using the modified runway method.[6] The costs are allocated to Scheduled Facilities and Semi-Scheduled Facilities, based on their energy, Contingency Reserve Raise and Regulation Raise in a Dispatch Interval.
Contingency Reserve Lower	Loss of load.	Reserve MW to respond to loss of load to restore frequency to an acceptable level.	Allocated to Market Participants based on the proportion of their Loads' metered consumption to total consumption per Trading Interval.

[6] The modified runway method is specified in Appendix 2A, as it will apply from 1 October 2023 (see the WEM Rules Consolidated Companion Version (https://www.wa.gov.au/government/publications/wem-rules-consolidated-companion-version).

ESS	Risk	Service Description	Cost Allocation
RoCoF Control Service	Rapid frequency changes can cause problems for automatic detection of frequency changes, and potentially result in damage or trip-off of generators and other system components. The RoCoF Control Service provides inertia.	The required quantity of RoCoF Control Service is a function of: • contingency size; • Contingency Reserve quantity; and • total inertia on the system. RoCoF Control Services has two functions: • the Minimum RoCoF Control Requirement to ensure RoCoF is restricted to below maximum limit; and • the Additional RoCoF Control Requirement, to allow trade-off between the quantity of Contingency Reserve Services required and the quantity of inertia required in the power system.	Allocated in two parts: • The Minimum RoCoF Control Requirement is shared equally (1/3 each) between: ○ Network Operators; ○ Generators (Registered Facilities with generation or storage systems); and ○ Non-Dispatchable Loads and Scheduled Loads. The Generator and Load shares are allocated to specific Registered Facilities and Loads in proportion to their Metered Schedules. • The Additional RoCoF Control Requirement (to trade off with Contingency Reserve Services) is allocated to Registered Facilities using the modified runway method. Members of each group can be exempted from the Minimum RoCoF Control Requirement if they can demonstrate to AEMO that their Facility’s Ridethrough Capability is greater than or equal to the RoCoF Ride-Through Cost Recovery Limit.