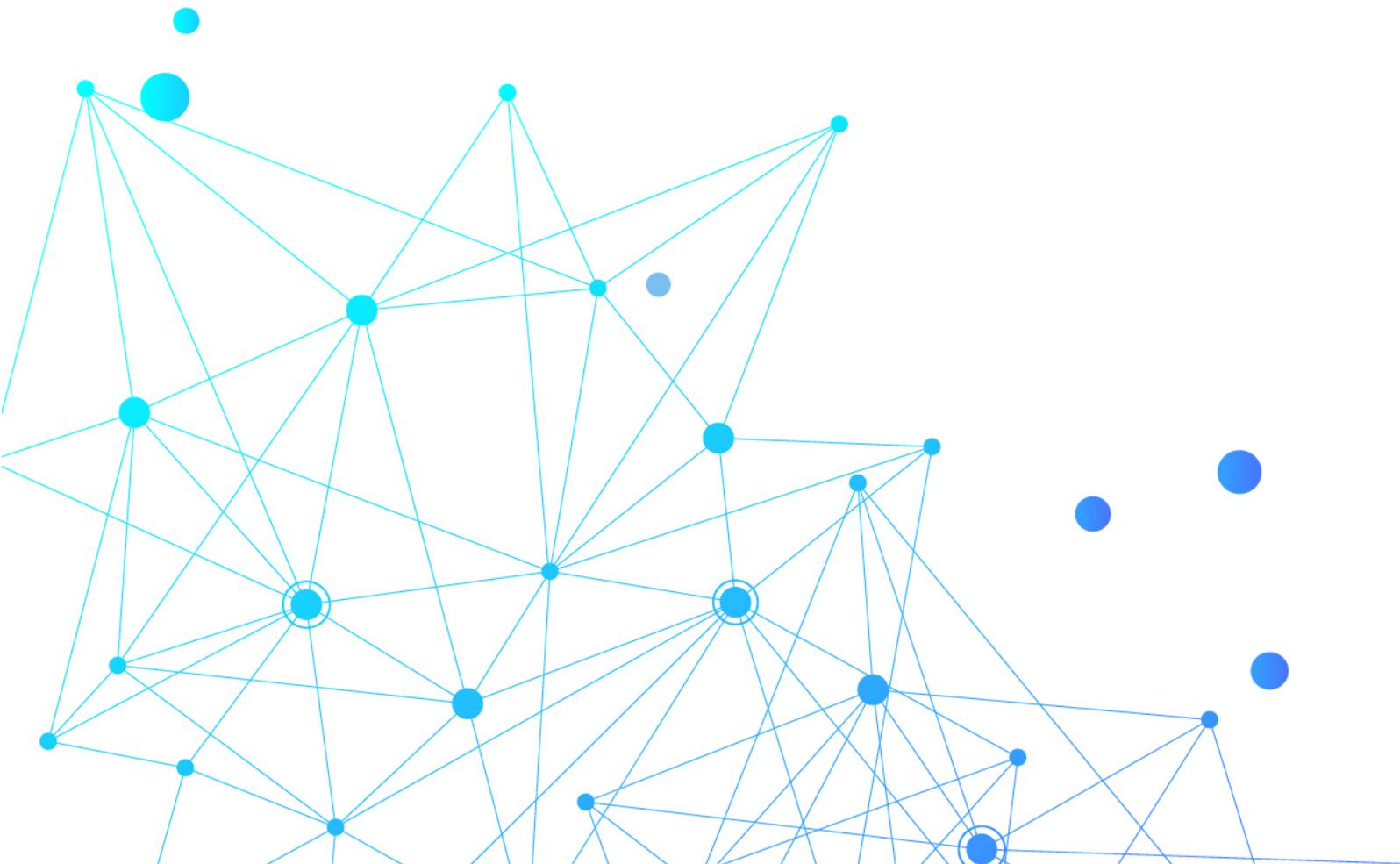




Energy Transformation Taskforce



Frequency Control Essential System Services: Acquisition, Cost Recovery and Governance

Information paper

August 2019

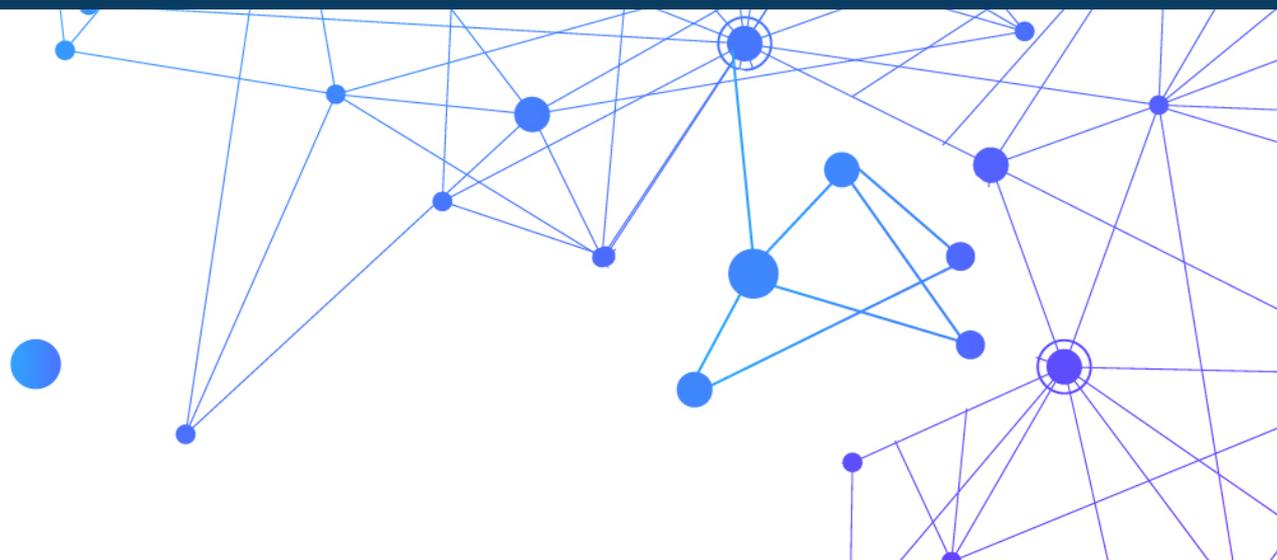


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1. Purpose

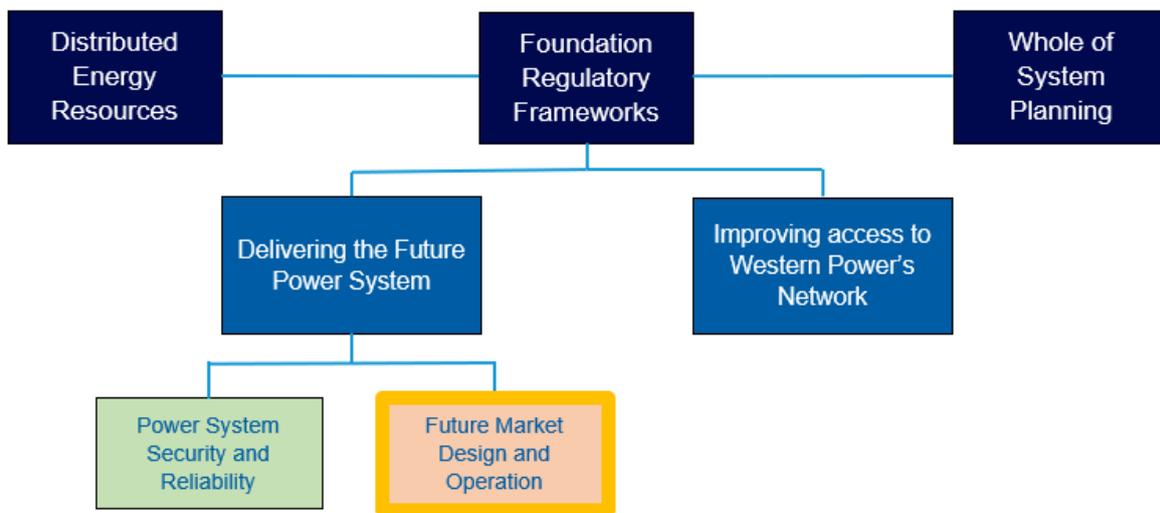
1.1 The Energy Transformation Strategy

This paper forms part of the work to deliver the Energy Transformation Strategy. This is the Western Australian Government’s strategy to respond to the energy transformation underway and to plan for the future of our power system. The delivery of the Energy Transformation Strategy is being overseen by the Energy Transformation Taskforce (Taskforce), which was established on 20 May 2019. The Taskforce is being supported by the Energy Transformation Implementation Unit (ETIU), a dedicated unit within the Department of Treasury.

More information on the Energy Transformation Strategy, the Taskforce and ETIU can be found on the Energy Transformation website at www.treasury.wa.gov.au/Energy-Transformation/.

This paper is prepared as part of the *Future Market Design and Operation* project (highlighted in **Figure 1**) within the Foundation Regulatory Frameworks work stream of the Energy Transformation Strategy.

Figure 1: Energy Transformation Strategy work streams



The Future Market Design and Operation project is undertaking improvements to the design and functioning of the Wholesale Electricity Market (WEM):

- modernising WEM arrangements to implement a security-constrained economic dispatch (SCED) market design that optimises the benefits of the introduction of constrained network access for Western Power’s network; and
- implementing a new framework for acquiring and providing Essential System Services (ESS).

1.2 The purpose of this paper

This paper is one of a series covering design elements of the new SCED market model. These changes are critical to support the continuing security of the power system and the efficient operation of the WEM in an environment of rapidly changing technology and consumer demand.

This paper outlines the high-level Frequency Control ESS (comprising several separate services) design directions approved by the Taskforce regarding ESS acquisition, cost recovery and governance. These design directions build on the Foundation Market Parameters previously endorsed by the Taskforce¹ and provide the basis for further technical and economic analysis, which will be communicated in future Taskforce information papers. This analysis includes the testing of a prototype for the dynamic determination of Frequency Control ESS requirements and modelling of total system costs when new ESS are co-optimised with energy in dispatch.

This paper is intended to be read in conjunction with the *Frequency Control Technical Arrangements*² information paper, which describes the classes of Frequency Control ESS required by the new WEM. Both papers build upon ESS concepts and analysis contained in the information paper *Technical Review of Essential System Services* prepared for the Taskforce by consultants GHD Advisory.

Subsequent papers on ESS will include the technical and economic analysis of the design decisions adopted by the Taskforce, and will present the detailed design of ESS acquisition methods (for Frequency Control and Locational ESS) and ESS scheduling and dispatch (including the co-optimisation of ESS and energy) endorsed by the Taskforce.

¹ The Taskforce approved Foundation Market Parameters to underpin the design of the new WEM in August 2019. These parameters are described in detail within the information paper *Foundation Market Parameters*, accessible through the Energy Transformation website.

² The Energy Transformation Taskforce's *Frequency Control Technical Arrangements* information paper is accessible through the Energy Transformation website.

2. Introduction

2.1 Frequency Control ESS

Frequency Control ESS are those used to manage the electrical frequency of the power system under a range of operational conditions. Frequency Control ESS may be segmented according to the circumstances under which an ESS is required (such as responding to a contingency event), as well as the speed, type (frequency raise or lower), and quantity of response required.

Frequency Control ESS is currently provided in the WEM through Load Following Ancillary Services (LFAS), Spinning Reserve Ancillary Service and Load Rejection Reserve. As currently designed, these services will not maintain power system security at the least sustainable cost and are incompatible with the new WEM arrangements required to respond to the energy transition.

2.2 Case for change to Frequency Control ESS acquisition

There are four main drivers necessitating change to current Frequency Control ESS acquisition arrangements.

1. Changes to generation mix and customer behaviour require new types of ESS to ensure secure and reliable power system operation.
2. The Foundation Market Parameters adopted by the Taskforce, including the adoption of a SCED market model, facility-bidding for all market participants, and co-optimisation of energy and ESS, require consequential change to ESS acquisition arrangements.
3. Current arrangements restrict the ability of some technology types to participate in the market.
4. Existing governance arrangements do not effectively support ongoing review of acquisition arrangements to ensure they provide the lowest economic cost.

2.2.1 Secure and reliable power system operation requires new types of ESS

The energy transformation creates both opportunities and challenges for the efficient demand and supply of Frequency Control ESS.

Key emerging developments observed in the WEM resulting from the energy transformation include:

- a trend toward a longer duration of minimum operational demand, and a change in the time of minimum demand;
- a trending reduction in maximum operational demand, and change in time of maximum demand;³

³ AEMO, 2019, *2019 Electricity Statement of Opportunities*, Chapter 5, including Figure 28: 'Total operational consumption in the SWIS, 2010-11 to 2017-18'

- increased variability of operational demand driven by the intermittency of current distributed energy resources (DER), such as small-scale solar photovoltaic (PV) systems;
- a substantial change in intra-day operational demand, requiring steeper ramp up in the late afternoon; and
- an expectation that larger, faster changes in frequency are likely to result from contingency events.

These changes mean faster-responding ESS are of greater value to the power system and will be required in future to maintain power system security. Current ESS acquisition mechanisms do not allow the desired speed of response to be valued and compensated.

2.2.2 Changes to support Foundation Market Parameters

Existing processes for acquiring Frequency Control ESS primarily use administrative mechanisms to set prices and quantities. Additionally, they provide the Australian Energy Market Operator (AEMO) flexibility to dispatch Synergy generators as a single portfolio.

The Taskforce decision to move to facility-based, co-optimised SCED at five-minute dispatch intervals means that a portfolio-based approach to Synergy dispatch will no longer be possible (or desirable). The Taskforce has already determined that Synergy will bid for and be dispatched on an individual facility basis. As such, new arrangements for acquiring Frequency Control ESS will be required.

The new arrangements will allow more cost-efficient dispatch overall. However, they will also require changes to the mechanisms designed to ensure efficient market outcomes, including those relating to monitoring, surveillance and market power control.

2.2.3 Enabling increased participation in Frequency Control ESS

Current Frequency Control ESS acquisition arrangements restrict the participation of renewable generators and DER (solar PV and battery storage systems). Changes to ESS acquisition arrangements should enable full participation by facilities that can potentially provide lower-cost frequency control and improve competition:

- *Large-scale intermittent generation:* Current wind and solar generation technology is capable of providing a response to increases in frequency at very low opportunity cost, and is already doing so in other parts of the world. As ESS becomes more valuable relative to energy, these generators may also wish to participate in Frequency Control ESS markets, thereby increasing competition in the supply of these services and reducing total cost.
- *Small-scale DER:* Changes to connection standards for solar PV located in the distribution system⁴ would enable the 'largest generator on the South West Interconnected System

⁴ Improved DER connection standards, including inverter standards, are being considered as part of the DER work stream of the Energy Transformation Strategy.

(SWIS)' to also provide frequency support,⁵ thereby reducing the requirement for centrally procured Frequency Control services.

- *Battery storage*: Recent investments in battery storage, such as the Hornsdale Power Reserve in South Australia and the Newman battery storage project in the Pilbara region of Western Australia, have shown that battery storage systems can significantly reduce the costs of ESS provision, but are unlikely to enter the market based on real-time market revenues alone.

Existing WEM synchronous generators are also restricted from participation in ESS markets. At times, facilities are dispatched in the Balancing Market with capacity available to provide ESS. However, these facilities are currently unable to participate in providing Spinning Reserve, and have chosen not to actively offer to provide LFAS.

2.2.4 Governance arrangements to support lowest overall economic cost in ESS

The governance and review mechanisms under current ESS arrangements do not include explicit consideration of the economic costs of the arrangements. Inefficient costs may result from the exclusion of potential providers, overly conservative requirement quantities, unnecessary curtailment or displacement of lower-cost generation, or the presence of market power that drives up prices.

The increased cost resulting from inefficiency in Frequency Control ESS acquisition manifests as increased revenue for the owners of the assets capable of providing the defined set of Frequency Control ESS. The benefits of more efficient and effective Frequency Control ESS, on the other hand, are distributed among:

- electricity consumers in the SWIS, who (assuming effective competition and retail price regulation) experience lower retail bills than otherwise;
- owners and users of DER that increase their net energy output and therefore reduce the volume and cost of their purchases from grid scale energy supply; and
- existing and potential large-scale renewable generators (and possibly thermal generators) that increase their energy output and revenues.

AEMO's annual determination of Ancillary Service Requirements focuses on the direct financial costs of meeting defined technical standards. The Economic Regulation Authority's (ERA) five-yearly review of Ancillary Service Requirements, Processes and Standards includes consideration of economic costs. However, this review is not carried out frequently enough to either support or reflect the ongoing changes in the power system. AEMO provides annual reports on technical and financial outcomes of ESS, but not on economic metrics showing the impact of specific ESS acquisition arrangements. Collectively, these arrangements make it challenging to identify whether the acquisition framework supports the overall least economic cost outcome; for example, by minimising the displacement of low-cost,

⁵ Revised inverter standards may allow for automated frequency response and improved fault ride-through, both of which may reduce the overall ESS requirement. Improved connection standards for DER do not preclude the ability of technologies such as aggregated Virtual Power Plants to participate as controllable generators that provide frequency control services.

but difficult to control, renewable generation by higher-cost, controllable, non-renewable generation.

The ERA has noted that outcomes in the LFAS market are not competitive⁶. This means that current ex-post monitoring mechanisms are not sufficient to drive efficient market outcomes.

2.3 Objectives and key considerations for new ESS acquisition framework

2.3.1 High level objectives

Taskforce design decisions on Frequency Control ESS achieve the WEM objectives by:

- maintaining the Frequency Operating Standard and relevant ESS standards;
- removing barriers to the efficient entry and exit of plant capable of delivering Frequency Control; and
- minimising the long-term, total, economic cost of Frequency Control ESS acquisition, having regard to the total economic costs, including wholesale and end user costs.

Table 1 below maps the Taskforce’s desired ESS acquisition outcomes against the individual WEM Objectives. These considerations guide selection of the options discussed in the remaining chapters of this report.

Table 1: WEM Objectives and the Taskforce’s desired ESS acquisition outcomes

	WEM Objective	Desired ESS Acquisition Outcomes
a)	to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system	<ul style="list-style-type: none"> • The Frequency Operating Standard and WEM Reliability Standard are met • Services are acquired at the least economic cost, covering both direct costs and indirect costs (WEM and broader economy)
b)	to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;	<ul style="list-style-type: none"> • ESS acquisition arrangements are technology neutral • ESS acquisition arrangements can provide the required level of revenue certainty to prospective new entrants • ESS acquisition arrangements ensure sufficient ESS-capable facilities are present on the power system when required, supporting new entry

⁶ ERA, April 2019, *Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2018*, pages 43-44.

	WEM Objective	Desired ESS Acquisition Outcomes
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	<ul style="list-style-type: none"> • Non-scheduled generators and utility-scale storage can participate in ESS markets, if efficient • DER can participate, if efficient • Reduction in the total volume of WEM carbon emissions
d)	to minimise the long-term cost of electricity supplied to customers from the South West interconnected system	<ul style="list-style-type: none"> • Combined Frequency Control ESS and wholesale prices are lower than they would have been without changes to Frequency Control ESS acquisition • ESS acquisition arrangements support monitoring and mitigation of market power
e)	to encourage the taking of measures to manage the amount of electricity used and when it is used	<ul style="list-style-type: none"> • Curtailment of output from DER in future (through future controllability of DER and/or improved inverter connection standards) is no more than necessary to meet Frequency Control ESS standards • The incidence and costs of curtailment of DER, other than due to network limitations, is significantly lower than under a defined baseline case

3. Method of acquiring Frequency Control ESS

The method of acquiring ESS must provide mechanisms to deliver efficient outcomes over two timeframes.

1. Operational: To efficiently make use of the facilities available at a single point in time.
2. Investment: To support the ongoing presence of an efficient mix of facilities over the longer term and ensure the availability of the service for operational use.

These two timeframes will be addressed through a combination of co-optimised real-time markets for operational timeframes and a supplementary procurement mechanism that can operate as required to provide sufficient certainty for new proponents over the investment timeframe.

3.1 Real-time optimisation

An open, real-time market for supply of Frequency Control ESS allows participation by all available (and capable) facilities. This is consistent with the Taskforce's endorsement of the Foundation Market Parameter to co-optimize real-time markets for energy and ESS in the WEM. Real-time markets provide a mechanism to ensure efficient operation of the fleet as it exists at a moment in time, based on least-cost utilisation of available resources.

ESS will vary in how they are co-optimised. Co-optimisation of a Rate of Change of Frequency Control Service is more complex than Regulation and Contingency Reserve (the three services are described in the Taskforce paper *Frequency Control Technical Arrangements*). This is because relationships between the amount of system inertia present on the system, the size of the contingency, and the reserve requirement are non-linear, meaning that the ability to trade-off different ESS against each other is reduced. However, the overall cost of meeting the power system's ESS requirements will still be most efficiently achieved through the implementation of real-time co-optimisation.

3.2 Supplementary procurement mechanism

Because of the relatively small size and level of market concentration of the WEM, and the partial disconnect that exists between the economic benefits and costs of ESS provision, the entry of more efficient and effective Frequency Control ESS providers under well designed real-time market arrangements alone is unlikely. There is a high risk of market failure in the form of inefficient pricing, and inefficient facility entry and exit signals.

Modifying existing market power mitigation measures for Frequency Control ESS prices (which focus only on ex-post alignment of Frequency Control ESS prices with direct costs) is unlikely to be sufficient to control undesirable behaviour. As such, it would not address the risk of market failure in longer-term entry and exit. Because of this problem, the Taskforce endorses the supplementing of real-time ESS markets with longer-term, centrally managed arrangements to provide an ex-ante market power control and facilitate the timely entry of efficient and effective new Frequency Control providers, as required.

Cost-based submissions into the supplementary mechanism process would provide an opportunity for ex-ante market power review by the ERA. However, this would only be possible for those facilities participating in the supplementary mechanism. As a result, participants

expected to have market power in the real-time markets must be mandatory participants in the mechanism.

The need for real-time co-optimisation precludes the use of contracts for physical availability in the form used in the current market. If long-term contracts for physical availability were used, no other parties would be able to provide the contracted quantities in real time. Any supplementary mechanism must provide incentives for availability, while still enabling co-optimisation of the entire fleet in the real-time market.

The Taskforce is investigating the appropriate form of a supplementary mechanism to sit alongside a real-time market. A mechanism under active consideration is one where a fixed availability payment is made to ensure the required reserve service will be available in real time, supported by obligations applied on the facility's offers to limit the exercise of any market power.

This mechanism would only be activated to the extent that the real-time market is unlikely to secure sufficient and timely investment in facilities to provide Frequency Control ESS, or when there is evidence that the exercise of market power is resulting in inefficient pricing behaviour. The supplementary mechanism would be activated by a regulator, with the decision being formed on the basis of defined triggers.

3.3 Taskforce Design Decisions – ESS Acquisition

The Taskforce has endorsed the following design directions to underpin the further analysis of options for ESS acquisition.

1. ESS will be acquired through a real-time market, supported by a supplementary mechanism that is triggered as required to ensure reliability and mitigate market power.
2. Real-time ESS markets and the supplementary mechanism (when triggered) will be open to participation from all capable facilities.
3. Some participants will be required to participate in the supplementary mechanism in order to mitigate potential for market power exercise in the real-time market.
4. With the exception of those required to participate in the supplementary mechanism in order to mitigate market power, facilities can participate in the real-time market, regardless of their participation in the supplementary mechanism.
5. The outcomes of the supplementary mechanism will still allow for co-optimisation of the fleet in the real-time market, ensuring the most efficient dispatch outcome is preserved.
6. The supplementary mechanism will be codified in the WEM Rules and will not involve bespoke negotiation processes.

4. Cost recovery of Frequency Control ESS

The Foundation Market Parameters endorsed by the Taskforce include the principle whereby market costs are allocated to those causing them to be incurred (the ‘causer pays’ principle). When applied to ESS cost recovery, the causer pays principle holds that the costs associated with the procurement of a service should be recovered from the participants who most directly increase the quantum of service required.

The Taskforce paper *Frequency Control Technical Arrangements* identified the need for three Frequency Control ESS to be centrally-procured by AEMO.

- Frequency Regulation: A service to continuously manage frequency deviations resulting from normal power system activity, separated into upwards and downwards components.
- Contingency Reserve: A service to manage larger frequency changes resulting from abnormal power system events, such as a ‘trip’ of a generator or network equipment, separated into upwards and downwards components.
- Rate of Change of Frequency (RoCoF) Control Service: A fast service to restrict the rate of change of frequency in the first few hundred milliseconds after a contingency.

4.1 Frequency Regulation

The requirement for Frequency Regulation is driven by the difference between the forecast dispatch and the actual required dispatch in any trading interval. There are four causes for this.

1. Forecast errors for large-scale wind and solar generation, which occur when actual output differs from the forecast generation level.
2. Scheduled generators and scheduled loads deviating from dispatch targets, other than in response to a frequency deviation.
3. Differences between the shape of the load change and generator ramping profiles within a dispatch interval.
4. Load forecast errors, which occur when the load on the power system differs from that forecast by AEMO. This includes unexpected variations in the output of non-market generators and DER.

Generators should only contribute to Frequency Regulation costs for variation from dispatch that is not the result of a contingency frequency event. Generators should also not be liable for Frequency Regulation costs when the generator is being held at a particular output level to provide an ESS.

On the load side, costs have historically been recovered based on overall consumption, as a proxy for a market customer’s contribution to forecast error. This proxy relationship is becoming less and less accurate over time. This is because the rise in ‘behind-the-meter’ DER, particularly solar PV systems, results in some loads reducing their overall consumption, while at the same time increasing their contribution to the volatility and the forecast error. This means a change is required to the mechanism for recovering Frequency Regulation costs from market customers.

4.2 Contingency Reserve

The requirement for Contingency Reserve is driven by the amount of energy lost in a credible contingency. This could be the injection of a specific generator, the demand of a specific large load, or the injection or offtake relating to multiple facilities affected by a single network contingency.

With the introduction of co-optimised dispatch, the market clearing engine will trade-off the costs of energy and Contingency Reserve and may determine that reducing the size of the largest contingency (by dispatching a large generator to a lower volume, for example) is the most cost-effective result. This means that interval-by-interval dispatch will drive interval-by-interval Contingency Reserve costs. Costs can continue to be allocated to generators using the current 'Runway Method'.

Behind-the-meter generation also contributes to the need for Contingency Reserve. If a behind-the-meter generator trips without a matching reduction in behind-the-meter load, the facility is relying on the Contingency Reserve held by the market to maintain secure operation. Current arrangements do not allow full recovery from these facilities.

Load Rejection Reserve costs are recovered from all market customers according to their share of consumption, not from large loads according to their contribution to the contingency. The quantum of the requirement for downwards Contingency Reserve due to upwards frequency excursions resulting from load rejection is caused by the size of loads which might trip. While the loss of a large market-registered load represents a contingency in the same way as the loss of a generator, the largest contributor is the extent of potential load that may be lost in a network contingency event. This load is spread over multiple retailers and it is not possible to identify the individual lost load amounts for each. While it would be ideal to allocate costs using a runway method (with individual load contribution based on the load level for the load used in market dispatch), it is not possible to determine what the steps on the runway would be, or to disaggregate the contribution of each participant to the requirement.

4.3 RoCoF Control Service

The requirement for the RoCoF Control Service and the corresponding cost is driven by:

- clearing engine optimisation of the trade-off between the contributions of RoCoF Control service and Contingency Reserve to restrict frequency nadir;⁷ and
- RoCoF safe limits, which are set to avoid damage to generators and load equipment, and to ensure proper operation of network components.

The level of RoCoF which can be ridden through is not the same for all facilities, so the safe limits will necessarily reflect the technical requirements of the least capable facilities in the power system. If all facilities were sufficiently robust to withstand high RoCoF levels for a short period, there would be no need for a specific service ahead of response from

⁷ Frequency nadir is the lowest point of system frequency beyond which load shedding is triggered. For the SWIS, this is 48.75hz.

Contingency Reserve providers (though a RoCoF Control service could still be used to reduce the required Contingency Response quantity).

If minimum network access standards are selected as the RoCoF standard for the power system, it is likely that, in the short-term, safe limit requirements will be driven by the characteristics of a relatively small number of synchronous generators on the WEM. Over the longer-term, such standards may also be driven by load ride-through capability and network protection settings, and the level of flexibility in these settings is not yet clear.

Because need for RoCoF Control Service is created from all these elements, placing incentives on each is necessary to reflect the causer pays principle, and to drive performance improvement that can reduce the need for the service.

The facilities driving the size of the contingency are also in some sense the 'causer', but spreading costs across participants based on their contribution to contingency does not provide incentive for those parties to improve system performance.

Costs could be allocated to generators with low RoCoF ride-through capability according to their output in a given interval, but there is no equivalent calculation for load and network components. As a result, a simpler approach will be required in these cases to divide costs between generation, load and network causers.

4.4 Taskforce Design Decisions – Cost Recovery

The Taskforce has endorsed the following design directions to underpin further development of cost-recovery mechanisms.

1. The costs of Frequency Regulation services in each interval will be recovered from the causers of frequency deviation according to their contribution to the requirement.
 - a) Intermittent generators according to their deviation from forecast.
 - b) Scheduled generators according to deviation from dispatch.
 - c) Loads according to their volatility.
2. The costs of Contingency Reserve in each interval will be recovered from the causers of frequency deviation (or a proxy) according to their contribution to the requirement.
 - a) Retain use of runway method for cost allocation of Contingency Reserve for generation contingencies.
 - b) Use interval-by-interval values for scheduled and intermittent generation and facilities behind a network constraint.
 - c) Include total generation of generators associated with intermittent loads in the runway calculation, except where a generator trip would not affect the total withdrawal or injection at the meter.
 - d) Recover costs of Contingency Reserve for load contingencies from all market customers according to their share of consumption in the trading interval.

3. The costs of RoCoF Control Service will be shared between generators (based on their RoCoF ride-through capability) and loads (including as proxy for network).

Specific calculations to underpin cost-recovery will be covered in a future Taskforce paper on market Settlement.

5. Governance

Due to the speed of the transformation of the power system and the inherent uncertainty this creates, current governance and oversight arrangements for ESS will also need to change. This includes, in the face of likely increases in direct financial costs for ESS, the need to consistently and transparently assess the economic benefits of technical settings that underpin ESS design – something that is not done currently.

Ongoing determination of technical standards underpinning ESS is an economic decision, not only a technical decision. Technical parameters (such as frequency limits, deadband for generator and DER droop response, and generator, load and network RoCoF ride-through standards informing the System RoCoF safe limits) are major drivers of not only the direct (financial), but also the indirect (economic) costs of ESS acquisition arrangements.

In order for market participants and regulators to understand changing dynamics, and manage the risks of poor economic outcomes through a period of substantial change, relevant and timely information is required on the following.

- Technical performance: understanding what is being done (e.g. dispatch and use) and what is being achieved (system performance);
- Financial performance: transparency on the costs of meeting the defined technical requirements; and
- Economic performance: how ESS markets are contributing to meeting WEM objectives (e.g. by supporting increased penetration of low-cost renewable generation to reduce overall costs for consumers).

Current arrangements include regular monitoring and reporting of technical and financial metrics, but not economic metrics.

Ongoing monitoring of market performance will be supported by the establishment of an explicit performance evaluation framework with ex ante performance targets for ESS markets. Performance targets will include explicit technical, financial, and economic targets. While metrics should map to the desired outcomes in **Table 1**, specific targets may not be clear until experience has been gained with the new arrangements.

The reviews can be designed so that ERA and AEMO track and report on performance metrics. Data on economic impacts can be used to inform regular reviews by the ERA of ESS acquisition arrangements and allow consideration of the economic impacts of technical settings.

The economic benefits and costs of technical parameter settings vary over time, depending on changing supply and demand conditions, including the generation mix and the relative economic cost of existing and new generation. This suggests that technical parameters should ideally be updated in line with changing supply and demand conditions to ensure that total economic costs are minimised.

The minimum frequency for reviews of ESS acquisition arrangements (including the underlying technical parameters) can be reduced from the present five years to three, with the first to be conducted within the first two years of the new market. A three yearly cycle would

allow alignment with the ERA's review of market operations under section 128 of the *Electricity Industry Act 2004*, which accommodates an overarching economic view. In addition, an out-of-sequence review of part or all of the arrangements could be triggered by a major deviation from ex-ante performance targets, notified changes in the future generation mix arising from the exit or entry of generation and storage facilities, or AEMO notification that a new ESS need had arisen (e.g. the need for a fast ramping service).

Reviews would seek to identify opportunities to minimise the economic cost of ESS acquisition through trade-offs between security and reliability standards and economic costs and benefits, with implementation of proposals via either the rule change process or the Minister.

ERA monitoring of AEMO and participant compliance with the Market Rules would remain a separate activity.

5.1 Taskforce Design Decisions – Governance

The Taskforce has endorsed the following design directions to underpin further development of the governance arrangements.

1. ERA reviews of ESS requirements, standards and processes will be conducted more frequently than the current five-years, with option for out of sequence reviews of part or all of the arrangements triggered by market conditions.
2. Future ERA ESS reviews will include an explicit assessment of the overall economic effects of underlying ESS technical parameters;
3. This assessment will be supported by a comprehensive set of market-wide performance targets including technical, financial and economic outcomes.
4. AEMO and the ERA will monitor and regularly publish data for key ESS performance metrics.