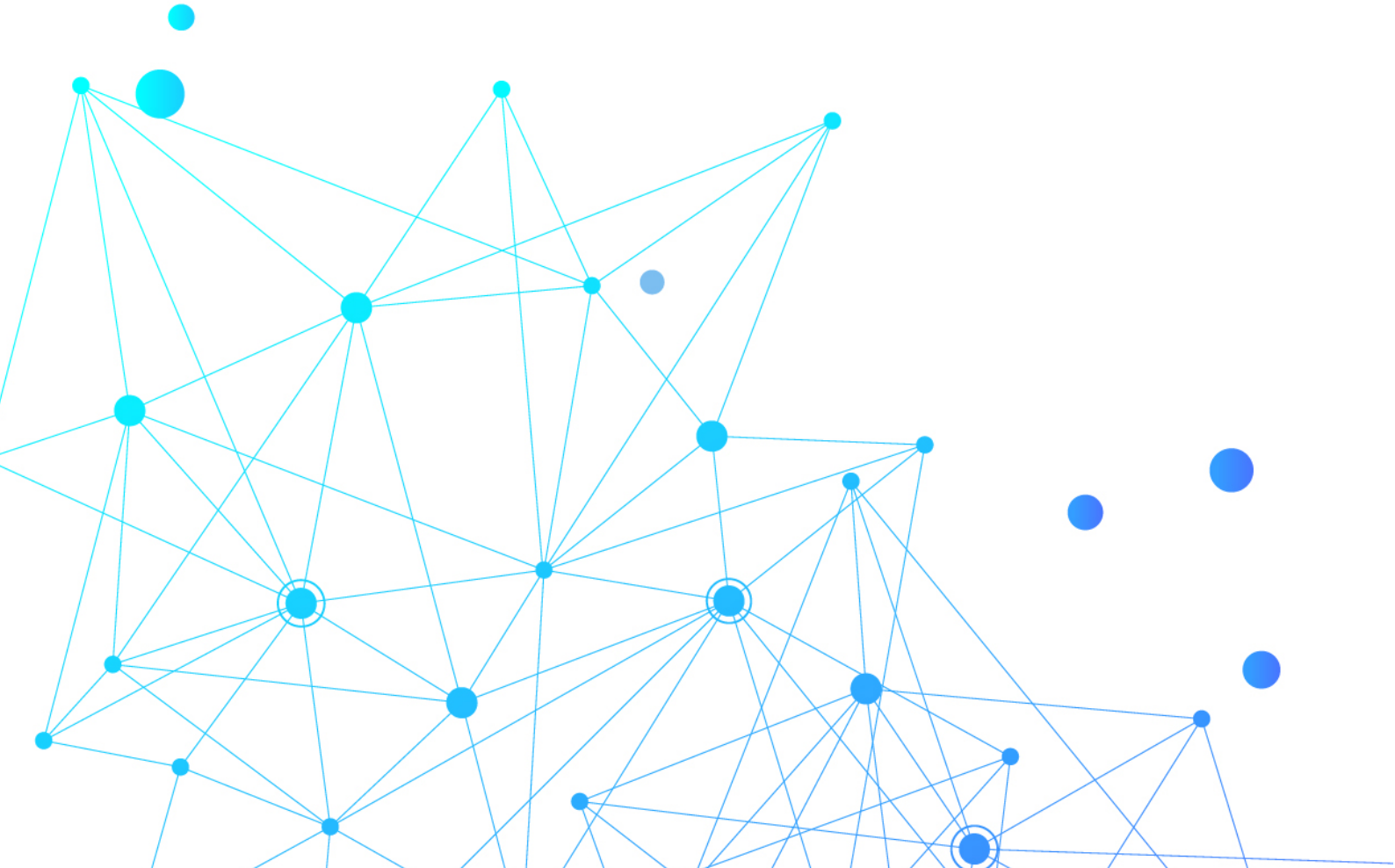




Energy Transformation Taskforce



Frequency Control Technical Arrangements

Information paper

August 2019

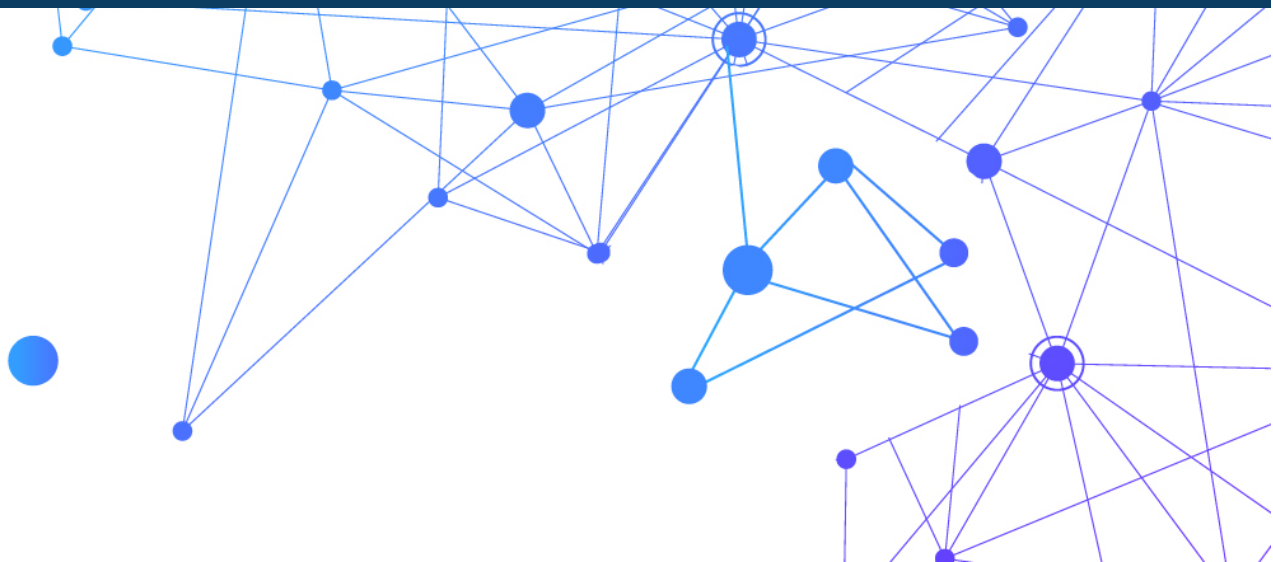


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1. Introduction and context

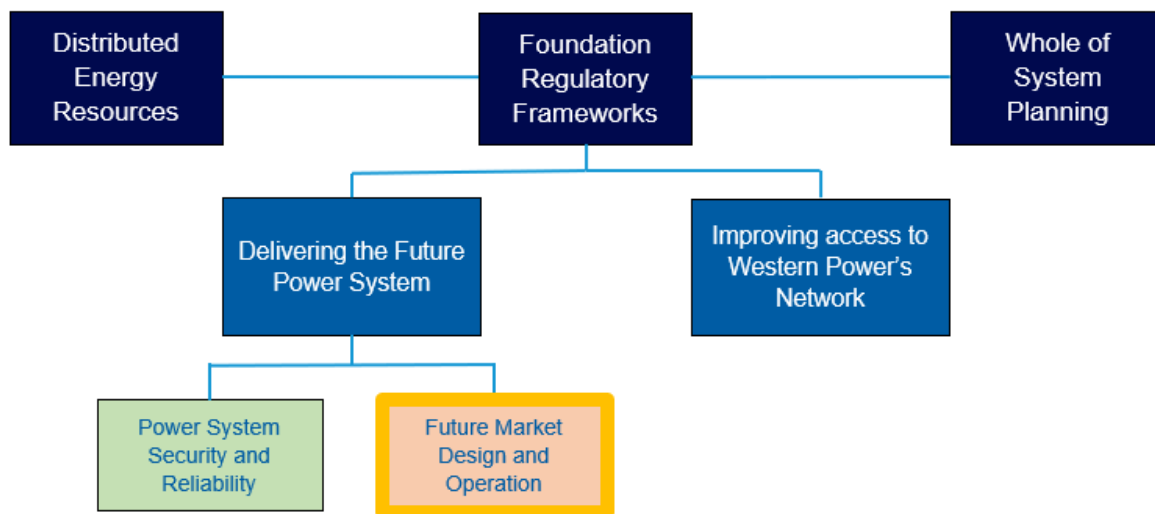
1.1 The Energy Transformation Strategy

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 <http://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

The purpose of this paper is to communicate the design approach for the technical components of the proposed Frequency Control ESS, one of the key elements of the future ESS framework.

1.3 Scope of this paper

There are two main components to the proposed new ESS framework:

1. Frequency Control ESS – The elements required to maintain power system frequency within the required standards, and to minimise the risk of unintended load shedding.
2. Locational ESS – The elements required to ensure secure and reliable power system operation for specific points or regions on the network (e.g. voltage control, reactive power control or system restart services).

This paper covers the technical arrangements identified to date for item 1 above, and the rationale behind the proposed approach. The companion paper *Frequency Control Essential System Services – Acquisition, Cost Recovery, Governance and Review*¹ covers the overall case for change to acquisition arrangements and the Taskforce’s high-level design decisions.

For the purpose of this paper, Frequency Control ESS include:

- Frequency Regulation: continuously balancing supply and demand to maintain frequency to normal levels. Frequency Regulation is currently provided in the WEM through Load Following Ancillary Services (LFAS).
- Contingency Response: responding to unplanned system events, including generator and load contingencies. Contingency Response is currently provided in the WEM through Spinning Reserve and Load Rejection Reserve services.
- Rate of Change of Frequency (RoCoF) Control: restricting the rate of change of frequency in the first few hundred milliseconds (ms) after a contingency. There is currently no equivalent fast-response service in the WEM.

A table comparing terminology used in this paper to describe future ESS and that currently used in the WEM can be found in Appendix A.

¹ The Energy Transformation Taskforce’s *Frequency Control Essential System Services – Acquisition, Cost Recovery, Governance and Review* information paper is available on the Energy Transformation website.

2. Technical issues identified

2.1 Background

Of the various reviews on both Australian and international power systems over recent years, one of the most significant in the Australian context has been the *Independent Review into the Future Security of the National Electricity Market*² (commonly referred-to as the ‘Finkel Review’). While primarily focussed on the National Electricity Market (NEM), the Finkel Review also has relevance for the South West Interconnected System (SWIS) in terms of describing the need for market design that ensures that sufficient essential system services are available and a service that provides a very fast response to arrest the RoCoF. The WEM has also had several broad reviews of Ancillary Service arrangements, one of the more extensive being the *2014 Ancillary Service Standards and Requirements Study*.³

In 2018, the Public Utilities Office engaged the services of GHD Advisory to conduct a technical review of ESS in the SWIS. This review included consideration of the recommendations and analysis of recent industry and international reviews and worked with AEMO to determine recommendations for a suitable technical ESS framework for the WEM to support the new SCED market design. These recommendations are outlined in the paper *Essential System Services Framework Review (ESSFR)*.⁴

In parallel to this, the Taskforce has been progressing work with AEMO and Western Power on revised frameworks for power system operating standards such as:

- the Frequency Operating Standard (FOS) for the SWIS;
- the Operating States framework, including specifications of credible and non-credible events; and
- Generator Performance Standards (GPS) as part of the connection arrangements to the SWIS.

These previous bodies of work form the basis for the Taskforce’s decision-making with respect to the technical ESS framework for frequency control. The Taskforce’s decisions also reflect feedback from stakeholders received through the former Power System Operations Working Group (PSOWG), convened under the Market Advisory Committee.⁵

2.2 Issues in the current ESS framework

The Taskforce has identified several short-comings in the current ESS framework that will increase the risks to the management of power system security and reliability if not resolved

² See <https://www.energy.gov.au/government-priorities/energy-markets/independent-review-future-security-national-electricity-market>

³ See <https://www.erawa.com.au/cproot/14770/2/EY%20Final%20Report.pdf> In August 2019, the Transformation Design and Operations Working Group replaced the PSOWG. Information about the new TDOWG is available at https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Energy_Transformation/Transformation-Design-Operation-Working-Group-Terms-of-Reference.pdf.

⁴ GHD Advisory, 2019, *Essential System Services Framework Review*, prepared for the Energy Transformation Taskforce, 18 July 2019

⁵ See <https://www.erawa.com.au/rule-change-panel-psowg>

as part of the move to the new market model (SCED). The problems needing to be resolved through changes to the ESS framework, identified through several different processes, are presented below.

2.2.1 Problems identified through the *Essential System Services Framework Review*

The ESSFR identified several important problems with the existing framework for providing ESS in the WEM:

1. The current framework is not specifically linked or aligned with the power system standards that it is intended to assist in meeting. This creates a discrepancy between the technical specification of the services to be provided and the outcomes that they must meet in order to maintain power system security.
2. The specifications of existing services are rigid and, in some cases, overly-specific. This can result in either over- or under-specifying the actual service requirement. In the worst case, an under-specified requirement may place the operation of the power system at risk. An example of this problem is a fixed quantity of Spinning Reserve service mandated under the current framework to cater for generator contingency events⁶ and specification of a 6 second response time.⁷ These service requirements can be insufficient to prevent underfrequency load shedding occurring under certain circumstances, where a larger or faster response is needed.
3. Including regulation reserve as part of contingency reserves⁸ exposes the power system to an increased risk of underfrequency load shedding or generator tripping.
4. The Ready Reserve Standard is ambiguously drafted and does not link with other dispatch and scheduling arrangements under the current market design. These requirements need to be clarified and linked unambiguously to the other operational processes to ensure secure power system outcomes are maintained.
5. Current service definitions are not technology neutral and restrict participation by wind and solar generators and energy storage providers. This not only reduces the available pool of potential providers (thereby decreasing competition and increasing price), but also prevents lower-cost and more innovative solutions from being employed which could provide improved power system security and price outcomes.

2.2.2 Issues with current Frequency Operating Standards

The current FOS for the SWIS reside in the Technical Rules. The Taskforce has found that the FOS is limited in what it describes and has several important shortcomings.

- It contains references to key elements that are not defined (e.g. Credible Contingency, Island, some operating bands).
- Response, stabilisation and recovery timeframes outlined in the FOS are ambiguous.

⁶ Currently specified at 70 per cent of the largest synchronised generating unit (WEM Rule 3.10.2)

⁷ WEM Rule 3.9.7

⁸ Discussed in section 5.5.3 of the ESSFR (p. 75)

- Situations where the FOS does not apply (such as microgrids) are not clearly identified.
- The location of the FOS in the Technical Rules is not aligned with the primary roles and responsibilities associated with the standard (split between the System Operator and Network Operator), which makes it difficult to build appropriate compliance and governance arrangements.

The Taskforce has determined that the FOS is best placed in the WEM Rules, as reflected in the Taskforce information paper *Power System Security and Reliability Regulatory Framework*.⁹ AEMO has presented recommendations to improve the specification of the FOS to the PSOWG at its September, October, and November 2018 meetings. These recommendations will be considered by the Taskforce in coming months in the context of changes necessary to support an improved ESS framework.

2.2.3 Issues with current Operating State definitions

The SWIS Operating States define the boundaries in which to operate the power system securely. The current SWIS Operating States have several ambiguities which need to be resolved or removed, including:

- the possibility of being in multiple SWIS Operating States at the same time (e.g. both Normal and High Risk);
- the possibility of being in no SWIS Operating State (e.g. neither Normal or High Risk);
- the lack of definition around terms used to describe the conditions for the SWIS Operating States; and
- the absence of two elements required to support the new ESS framework, namely:
 - the concept of a Credible Contingency Event; and
 - the inclusion of a practical timeframe to respond to power system security and reliability risks.

Recommendations to improve the Operating States framework have previously been presented to the PSOWG, including a new framework for defining (and re-defining) Credible and Non-Credible Contingency Events. The Taskforce will consider these recommendations and a new Credible Contingency Framework in coming months. These changes will support an improved ESS framework.

2.2.4 Issues with Generator Performance Standards

The GPS describe the minimum requirements that a facility must meet under different operating conditions when connected to the power system (under both normal operating and fault conditions), including the following.

- Droop¹⁰ requirements: automatic response requirements to frequency disturbances.

⁹ The Taskforce information paper *Power System Security and Reliability Regulatory Framework* can be found on the Energy Transformation website.

¹⁰ Droop response is the automatic adjustment of output of a generator to respond to changes in system frequency, based on a defined rate of change. The generator must increase output up to a

- Reactive power and voltage control requirements: to support voltage management.
- Stability requirements: to avoid power system oscillations.
- Fault ride-through requirements: to ensure the generator remains connected during fault conditions.

The GPS are intended to provide a level of assurance as to what performance can be expected from facilities connected to the power system. This performance subsequently impacts the levels of ESS required to maintain power system security and reliability.

The current GPS reside in the Technical Rules. They are out-dated and do not reflect the changing nature of the power system or cater for emerging security issues (such as System Strength). There is also limited capability to monitor or enforce compliance of facilities against the GPS.

Western Power and AEMO have jointly developed a Generator Performance Guideline that describes the changes required to the GPS to support the changing needs of the power system, and to better allow for different technology types with varying capabilities. The Taskforce has determined that the revised GPS for newly-connecting, large-scale generators (transmission-connected market participants with over 10 megawatts capacity) and associated monitoring and compliance framework) are best implemented through the WEM Rules (as reflected in the Taskforce information paper *Power System Security and Reliability Regulatory Framework*).

2.2.5 Taskforce Design Decisions – ESS Framework

1. The new ESS framework will be:

- outcomes-based, linking to the required power system operating standards, rather than mandating specific quantities;
- sufficiently flexible to support requirements to be determined dynamically (reflecting rapid changes to the power system), and to allow for multiple service providers with varying characteristics; and
- technology-neutral, with participation determined by the capability to meet requirements, rather than technology type.

2. To support the new ESS framework:

- the FOS will be defined to avoid ambiguity so it can direct the required outcomes, and will be moved to the WEM Rules where it is better aligned with the roles and responsibilities of the System Operator, Network Operator, and market participants;

specified maximum level in response to a declining system frequency and decrease output down to its lower technical limits in response to an increasing system frequency. Movements are also subject to a defined frequency change ‘deadband’ inside which the generator is not required to increase or decrease output (currently +/-0.025Hz for the SWIS), and are only required to be sustained for a short period (currently 10s).

- a Credible Contingency framework will be defined; and
- a robust set of GPS and associated compliance monitoring and enforcement framework will be implemented through the WEM Rules, including the retention of mandatory provisions such as droop requirements.

2.3 Emerging power system issues

The ESSFR identified issues likely to arise as the levels of synchronous generation on the power system decrease.

- An increased RoCoF experienced following contingencies. If not controlled to a 'safe level' the increase in RoCoF following a generation or load contingency risks causing damage to existing generation plant, generators tripping to avoid damage, or inadvertent disconnection of generators through the operation of anti-islanding protection. Tripping of plant following a contingency can also exacerbate the frequency disturbance leading to partial system collapse and/or significant levels of load shedding.
- The need to ensure ESS can be provided by non-synchronous facilities, to avoid scarcity issues from arising, enable the system to access the benefits of new technologies and facilitate the least-cost supply of these services from greater competition.
- The need to deliver control responses to contingency events more quickly to arrest the frequency change and keep frequency within the limits specified in the FOS.

2.3.1 Contingency Response

Following the Finkel review, AEMO conducted analysis based on research from the Melbourne Energy Institute¹¹ examining the relationships between different contingencies events, the available inertia¹² on the power system, and the level of primary frequency response (PFR)¹³ required to maintain secure power system operation with increasing RoCoF.

This analysis has resulted in the findings published in the paper *Contingency Response in the SWIS*,¹⁴ which identifies a fundamental relationship between inertia, contingency size and PFR that AEMO has modelled mathematically.

¹¹ Melbourne Energy Institute, 2017, *Power System Security Assessment of the future National Electricity Market*. Available at <https://www.energy.gov.au/publications/power-system-security-assessment-future-national-electricity-market>

¹² System inertia provides a physical, sub-second inertial response to contingencies. Physically rotating generation (and loads in reverse) convert kinetic energy (due to their motion) into electrical energy. In the event of a contingency, a rotating generator will, without control, supply electrical energy to balance the power system demand. This response slows down as its rotating components slow down. Following these automatic physical responses, active control is required. System inertia is the aggregate of inertial response from connected generation and load.

¹³ The energy injected into the power system by a facility in response to a contingency event, analogous to Spinning Reserve and Load Rejection Reserve in the current WEM.

¹⁴ AEMO, 2019, *Contingency Frequency Response in the South West Interconnected System*, July 2019, Available at: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Contingency-Frequency-Response-in-the-SWIS.pdf

2.3.2 Primary Frequency Response

The ESSFR reviewed the analysis and modelling conducted by AEMO, making several recommendations around PFR.

- The level of PFR should vary with inertia and the size of the largest contingency.
- A model developed by AEMO should be used to determine the PFR requirement (both in terms of quantity and timeframe).
- Frequency raise and lower requirements should be individually specified.
- Frequency regulation (provided by LFAS under the current market arrangements) quantities should not be counted towards meeting the PFR requirement.
- Accreditation of PFR providers should include consideration of how quickly they can provide their response.
- Appropriate operating margins should be developed and formalised in procedures by AEMO.
- AEMO should develop and formalise in procedures the technical specification and accreditation requirements for PFR providers.

The Taskforce has determined that the new ESS framework will implement these recommendations.

The ESSFR also suggested investigating whether the WEM Rules and/or Technical Rules should include a similar concept to the NEM Emergency Frequency Control Schemes.¹⁵ These schemes provide non-ESS based mechanisms to deal with specific high-impact contingency scenarios to help offset the levels of Contingency Response Reserve that would otherwise be required. The Taskforce will consider this recommendation in coming months following further analysis by AEMO.

2.3.3 RoCoF Control

The ESSFR suggested that 'safe' levels of RoCoF be determined and added to the FOS to ensure power system stability,¹⁶ and that a RoCoF control component be considered as part of defining the Contingency Response Service to help offset the levels of PFR required and ensure the proposed safe RoCoF levels are maintained.

2.3.4 Secondary Frequency Response

As discussed in the paper *Contingency Response in the SWIS* the restoration of system frequency back to normal typically requires a secondary (and sometimes tertiary) response to

¹⁵ Under S5.1.10.1a of the National Electricity Rules.

¹⁶ With initial values proposed based on recently-defined generator performance guidelines developed by Western Power and AEMO, with reference to generator performance standards and safe levels prevalent in the NEM. Generator performance guidelines are available at: <https://westernpower.com.au/media/3226/generator-performance-guideline.pdf>

instruct generators to increase output over and above what they may have already done to arrest the frequency decline as part of providing PFR in the first instance.

This secondary frequency response (SFR) is typically initiated through Automatic Generator Control¹⁷ (AGC) functionality and/or manual instructions by the system operator,¹⁸ and tertiary frequency response (TFR) is typically a result of energy re-balancing occurring over a longer time period (5-10 minutes).

The ESSFR observed that it may be unnecessary to have both a PFR and SFR service where the same providers are capable of sustaining and increasing the initial PFR response over both the PFR and SFR timeframes. The recommendation was therefore to ensure, where possible, PFR providers have AGC capability enabled to allow any spare PFR capacity to be used to move the frequency back towards the normal range after it has been arrested.

Additionally, the ESSFR stated that frequency could be restored back to the normal range by specifying a combined PFR + SFR quantity equal to the size of the contingency. While this is the case, the FOS also can potentially allow for a lower 'settling' frequency for a period of time which is sufficiently above the load shedding frequency to avoid inadvertent load shedding for small load and generation movements while waiting for TFR to take effect following the next re-dispatch in the energy market and restore the frequency to normal. A settling frequency is not a current feature of the SWIS FOS. However this does exist in other jurisdictions and will be determined for the SWIS in order to reduce the combined PFR/SFR requirement.

2.3.5 Frequency Regulation Service

The ESSFR noted that the current frequency 'regulation' service (as opposed to contingency) quantities required to address each of the factors that drive the requirement cannot be easily identified through simple analysis of historical data. This makes it difficult to forecast the level of regulation service that might be required with changes to the energy market, such as a move to 5-minute dispatch intervals, and through the implementation of facility bidding.

The ESSFR also noted that the current requirement for droop to be enabled within the normal frequency band was also playing a role in helping to maintain a tight frequency band. This is particularly the case for units that are enabled to provide other frequency services (such as Contingency Reserve PFR). The ESSFR recommended that this requirement should be retained to avoid increasing the quantities of frequency regulation.

In the existing market, a subset of facilities is selected to regulate frequency by responding to a central AGC dispatch mechanism. The remaining facilities dispatched for Contingency Response are directly responding to their own measurement of frequency (local control). However, droop settings on the facilities enabled for Contingency Response (described above in section 2.2.4) also result in the broader generation fleet responding quickly to smaller frequency variations and assisting the slower AGC-enabled machines to regulate frequency. This approach has several system benefits as it:

¹⁷ Central automatic coordinated control over a group of enabled generators via a SCADA system to drive system frequency back to normal, typically with control cycles in the order of two to four seconds.

¹⁸ Control signals are sent every four seconds.

- reduces the performance (speed) requirements on the designated AGC Frequency Regulation machines, allowing a larger range of facilities to participate;
- reduces the overall Frequency Regulation requirement, by assisting during large but low-probability frequency swings; and
- increases system resiliency during islanding, dispatch system or AGC failure events.

In practice, AGC enabled facilities providing Frequency Regulation respond with a much larger degree of variability than machines locally adjusting to frequency via their droop controllers (due to the different nature of the control actions).

The ESSFR included some analysis to show indicative levels of support that mandatory droop provides towards Contingency Response. While the analysis indicated the levels of support were not significant, the recommendation was to retain mandatory settings to ensure ongoing power system stability is maintained.

The combination of both local droop control and AGC Regulation Service creates more secure operation, a reduction in the required level of AGC-based Regulation Service and a better frequency regulation outcome overall. The net result is a shared benefit of a stable and reliable operating environment, while efficient providers have an incentive to supply greater volume and performance through a paid Regulation Service.

2.3.6 Other mandated response

In addition to large generator droop, other mandatory connection requirements are currently specified by Western Power's Technical Rules for certain types of DER¹⁹ in Western Power's *Network Integration Guideline - Inverter Embedded Generation*.²⁰ These requirements include: a 'deadband' frequency range, close to the normal operating frequency, within which DER facilities do not respond to frequency variations; the droop response to frequency changes outside the deadband; and limits related to inverter connections at different network voltage levels.

Changing requirements under this instrument will, over time, change the aggregate (and local) behaviour of the DER fleet. Improvements to DER connection standards being considered under the Energy Transformation Strategy's DER Roadmap will have the effect of reducing the requirements for Frequency Control ESS required by the system.

Finally, under-frequency load shedding (UFLS) is where load is cut off in response to frequency excursion beyond an extreme low point. This is a fall-back service for highly unlikely contingencies and must be retained as a final backstop to arrest frequency decline and avoid complete system collapse. No requirements to change the nature or settings of this service have been identified at this time. However, changes may be considered in future if higher safe RoCoF specifications deliver significant economic benefits as current UFLS response times may not be sufficient under higher RoCoF conditions.

¹⁹ Specifically, inverter connected generation and storage resources.

²⁰ Western Power's Network Integration Guideline – Inverter Embedded Generation can be found at: <https://westernpower.com.au/industry/manuals-guides-standards/>

2.3.7 Taskforce Design Decisions – Response to Emerging Issues

1. The new ESS framework will support dynamic calculation by AEMO of Contingency Response requirements, taking into account available inertia and contingency size.
2. ESS accreditation and dispatch will reflect the fact that faster PFR providers provide greater support to the power system as the level of inertia declines.
3. Frequency raise and lower will be individually-specified.
4. Frequency regulation (provided by LFAS under the current market arrangements) quantities should not be counted towards meeting the PFR requirement.
5. Appropriate operating margins should be developed and formalised in procedures by AEMO.
6. AEMO should develop and formalise in procedures the technical specification and accreditation requirements for PFR providers.
7. Safe RoCoF levels will be specified in the FOS.
8. A settling frequency will be determined (either in the FOS or elsewhere) to help reduce combined PFR and SFR requirements.
9. Mandatory droop response within the normal frequency band assists in maintaining a tight frequency range and will be retained.
10. Changes to DER response requirements will be effected via the Western Power connection guidelines, through the DER Roadmap workstream.
11. Under frequency load shedding arrangements will be retained.

3. Technical Options for Frequency Control Services

The ESSFR described changes to the ESS framework necessary to support the SWIS through the transformation from a centralised system based on large synchronous generation to a decentralised system with a high-level of supply from inverter technologies, such as solar PV, wind, and battery storage. It set out what the system needs from Frequency Control services.

The Taskforce has formed a view on how those system needs can be met by combining the requirements of the ESSFR into defined segments that can be acquired by market, contract, or mandated mechanisms. The Taskforce's view on the definition of ESS market segments will be subject to additional economic and technical analysis, which will be communicated to the Transformation Design and Operation Working Group and through a subsequent information paper.

3.1 Key design criteria

Design options for new ESS acquisition arrangements being progressed by the Taskforce include only those which:

- enable delivery of a secure power system;
- are consistent with the Taskforce's Foundation Market Parameters; and
- can be implemented in the timeframes required and are of a level of complexity consistent with the level of benefits expected to be provided.

ESS acquisition arrangements that clearly fail one of these criteria have not been considered further by the Taskforce.

When comparing ESS acquisition options, the Taskforce has considered the extent to which the option:

- allows effective use of diverse fleet capability (both existing and future);
- allows procurement of services at an efficient overall cost (across all power system services);
- supports monitoring and mitigation of market power; and
- minimises administrative costs (associated with market operation).

3.2 Separating Frequency Regulation from Contingency Response

Modern electricity systems typically segment the reserve maintained for real-time frequency fluctuations expected during normal operations (Frequency Regulation) from the reserve maintained for response to contingencies (Contingency Response). This is to reflect the different operational requirements:

- Providers of Frequency Regulation must be able to respond with upward and downward deviation in almost every trading interval as a response to AGC signals.

- Providers of Contingency Response are only required to provide a small response through local droop control for small frequency deviations, but are required to provide a much larger response in a short timeframe in response to large frequency deviations (when the response delivered is critical to system security).

Many facilities can provide one service more cost efficiently than the other. Contingency Response can typically be efficiently provided by some loads, while the same loads cannot efficiently provide the more granular and regularly required Frequency Regulation response. Segmentation allows participation by a suite of demand-side providers for the upward deviation required by Contingency Reserve who have a low- or zero-cost of maintaining reserve. This can materially reduce the total economic cost of providing reserve – in jurisdictions where interruptible load is allowed to participate, they form a significant portion of the market.²¹

Further, if the services are not separated, there is a risk of insecure outcomes as identified in the ESSFR. Specifically, a subsequent smaller frequency variation following a contingency event due to load or non-scheduled generation movement could result in ULFS.

Some markets, including PJM, New England, and New Zealand, maintain a single Regulation Service (for response to frequency changes both above and below the target system frequency). Others, including California, Texas, the NEM, and the current WEM, separate Regulation Services into upwards and downwards response components. This flexibility allows facilities running at their minimum or maximum output to participate in the provision of Regulation Services, which is important in a small system such as the SWIS. It also allows facilities to participate in one direction only, where it is not cost-effective for them to reserve capacity to respond in both directions.

Most markets do not typically further segment Frequency Regulation, but it is possible to include a specific ‘fast ramping’ service, whereby facilities capable of ramping quickly can be held in reserve for a future trading interval in which the system ramp rate is projected to be much higher than the current interval – for example in the ‘duck’s neck’,²² where underlying demand is increasing at the same time as solar generation is decreasing.

As the ‘duck’s belly’²³ continues to deepen over future years, either Frequency Regulation quantities will need to increase, or a dedicated fast ramping service may need to be introduced. Market monitoring and evolution processes will need to identify whether a separate service will provide better overall market outcomes in such intervals than just relying on standard Frequency Regulation and energy dispatch.

²¹ In New Zealand, interruptible load makes up 30-60 per cent of the volume of reserve offers in any given trading interval.

²² That part of the duck-shaped daily demand profile – or ‘duck curve’ – for the SWIS, which reflects the steep ramp up in demand through the late afternoon and early evening and solar irradiance, and therefore solar PV output, declines, with a corresponding rapid increase in demand from the grid.

²³ The low demand period of the duck curve during the day when solar PV output is high.

3.2.1 Taskforce Design Decisions – Separation of Regulation and Contingency Reserve

1. Frequency Regulation and Contingency Reserve services will be provided separately, providing both security and economic benefits.
2. Segmentation of regulation reserve to raise and lower components will be maintained.
3. The ESS framework will support introduction of new services in the future as necessary, including a potential future 'ramping' service.

3.3 Options for segmenting Contingency Response Services

As identified in Section 2, the speed of Contingency Response is critical to maintaining the security of the future power system. That means any proposed segments for Contingency Response need to allow for shorter timeframes than current definitions.

Responses also need to consider the diverse capabilities of potential providers. Response of each individual facility will differ depending on its technology type, size, configuration and loading at the time a contingency occurs.

Spinning Reserve is currently provided by Gas/Diesel, Coal and Interruptible Load facilities. System needs identified in the ESSFR and response curve breakpoints present in the existing generation fleet lead to the identification of the set of potential options in **Table 1** below.

The fundamental differences between the six options identified are the presence or absence of a service to control RoCoF (as discussed in the ESSFR) and the number of time segments.

The optimal selection is a function of the capability of current and likely future ESS providers.

Table 1: Feasible ESS technical options identified

#	Specification	Time segments
T1	<p>One Contingency Response Service</p> <p>This is a single Contingency Response Service, incorporating PFR and SFR across all required timeframes.</p> <p>Facilities who are not able to respond within this timeframe will still be able to provide the service, but would have a lower level of accreditation relative to a faster acting provider.</p>	250 milliseconds (ms) to 15 minutes (min)
T2	<p>T1+RoCoF Control Service</p> <p>Same as T1, but includes a RoCoF Control Service, which provides an inertial (or equivalent) response to immediately slow the rate of frequency change over the initial part of a frequency excursion.</p>	
T3	<p>Two Contingency Response Services, segmented by time</p> <p>As for T1, but with a fast-acting service (PFR) and a delayed acting service (delayed PFR) covering SFR as well.</p> <p>Allows faster-acting facilities that are unable to sustain for the whole period to be accredited.</p>	<p>a) 250 ms to 2 seconds</p> <p>b) 2 seconds to 15 min</p>
T4	<p>T3+ RoCoF Control Service</p> <p>As for T3 but includes a RoCoF Control Service.</p>	
T5	<p>Three Contingency Response Services, segmented by time</p> <p>As for T3, but with a second, longer delayed acting service covering SFR as well.</p> <p>Allows slower acting facilities that are unable to sustain for the whole period to be accredited.</p>	<p>a) 250 ms to 2 seconds</p> <p>b) 2 seconds to 60 seconds</p> <p>c) 60 seconds to 15 minutes</p>
T6	<p>T5+ RoCoF Control Service</p> <p>As for T5 but includes a RoCoF Control Service.</p>	

3.4 Future fleet capability

The fundamental shift in Western Australia's energy transformation is the move – over time – from a system dominated by large, synchronous machines to one dominated by inverter-based systems²⁴ and demand side response, which perform differently to traditional generation technologies.

New inverter battery storage technologies are expected to be cost-competitive for ESS provision. More scheduled and interruptible load participation in ESS is also expected. Intermittent generation (wind/solar without storage) is technically capable of providing services, and trials²⁵ have identified strengths and weaknesses associated with such technologies doing so. The economics of withholding low or negative marginal cost capacity in order to provide ESS means their regular provision of raise response services is unlikely. However, they can provide a useful lower service in response to a high frequency deviation.

Future ESS providers are likely to fall into one of three classes.

1. Synchronous machines, which respond instantly to changes in frequency due to the physics of their operation, with a subsequent decrease then a slow increase in support over seconds and minutes.
2. Interruptible loads, which respond very fast (but not instantaneously), with the potential to provide maximum output within the first second of a frequency excursion, then maintaining the same level of performance for the 15-minute duration of a Contingency Response.²⁶
3. Inverter-based technologies, which can respond very fast (but not instantaneously) and meet any defined response curve (though a storage battery will be limited by how much energy it holds, and an intermittent generator by the extent to which it has already been curtailed to provide frequency response).

All three classes are capable of providing PFR and SFR in a way that can be assessed against the required response curve,²⁷ but they differ materially in their response within the first few hundred milliseconds of a contingency event.²⁸ This difference in response requirements over very short timeframes is the factor which will define the ability of facilities to contribute to the new ESS segments.

3.5 Separation of RoCoF Control service from PFR/SFR services

The requirement for RoCoF Control response varies depending on power system conditions. Establishing a mandatory minimum RoCoF Control Service quantity at all times would be inefficient (as it would need to over-specify the requirement for the case of a minority of

²⁴ The total contribution of rooftop PV is already the largest injection on the power system.

²⁵ For example, the Hornsdale Windfarm 2 FCAS trial. See: <https://www.aemo.com.au/-/media/Files/Electricity/NEM/Strategic-Partnerships/2018/HWF2-FCAS-trial-paper.pdf>.

²⁶ A specified 15-minute duration would be consistent with current requirements and under 5-minute dispatch enable two full dispatch intervals to replenish frequency response capability.

²⁷ The required response curve is the defined aggregate quantity and speed of response required in order to maintain system security following a frequency deviation.

²⁸ Although an interruptible load cannot assist in restoring the frequency towards the normal band like other AGC-based SFR services

intervals), as would requiring a minimum number of connected synchronous facilities - a proxy for the underlying RoCoF control requirement.

As per the discussion in Section 2, there is an interplay between the largest contingency, the level of system inertia on the power system, and the required PFR. Higher levels of system inertia or a smaller contingency each reduce the quantum of PFR required, and vice versa.

Defining a separate RoCoF Control Service would allow the relationship between system inertia, PFR and contingency size to be explicitly reflected in the market clearing process (if not the clearing engine itself), and for RoCoF Control Response requirements to be set specific to each trading interval, and only in those intervals where it is required. This means the clearing engine could include constraints which account for the different mechanism by which facilities provide this service, resulting in a more accurate co-optimisation of services, and a lower overall cost for market dispatch.

To measure, evaluate, ensure availability, and co-optimize system inertia with reserves, the Taskforce considers that there should be two separate Contingency Response ESS services (with separate acquisition requirements and methods). As such, the only technical options selected by the Taskforce for further technical and economic analysis are T2, T4 and T6 (as described in Table 1).

Additional work remains to confirm the implementation approach to these technical options in the clearing engine. Further detail will be provided in coming months in a future Taskforce information paper relating to ESS scheduling and dispatch (and co-optimisation with energy).

In defining the quantity of RoCoF Control Service a given facility can provide, the performance, reliability and impact of synchronous inertia in managing RoCoF are well-understood and established, with large bodies of supporting research and evidence. The quantity of inertia is unambiguously measured from a machine's physical rotating mass (commonly expressed in megawatt-seconds, the rotational kinetic energy at 50 Hertz). The contribution of a given facility thereby serves as an appropriate baseline definition for the RoCoF Control service.

The fast-response capability of inverter-connected facilities can mimic the effect of physical inertia during contingencies, but cannot act as a direct substitute, as it differs in two key aspects, namely that:

1. it relies on electronic detection of area-frequency, which is subject to noise and inherently requires a delay (on the order of several hundred ms) during the critical response period; and
2. rotating inertia is physically coupled to the electrical system, and fundamentally cannot fail in response to a contingency.

As technology develops and the capability of fast response technology becomes better understood through live deployment, it is likely to emerge that an inertial equivalent for these facilities can be securely formulated, and thereby enable direct participation on the RoCoF Control Service.

3.5.1 Taskforce Design Decisions – RoCoF Control

1. A RoCoF Control Service will be defined separately from Contingency Reserve.
2. RoCoF Control Service will be defined in terms of inertial megawatt-seconds (MWs) or MWs equivalent.
3. AEMO will monitor dynamic system conditions and facility performance to investigate possible MWs approximations, to allow future non-synchronous providers to accredit and participate directly in the RoCoF Control Service.

3.6 Further Segmentation of Contingency Reserve

3.6.1 Preference for a single Contingency Reserve segment

Qualitative factors drive towards a non-segmented approach Contingency Reserve acquisition. This differs from the ESSFR, which recommended a three-breakpoint approach to setting PFR requirements. Responses (whether procured via one, two, or three segments) would be defined on a curve specifying levels of 1-, 2- and 6-second response.

For any given level of system inertia on the power system, sufficient capacity must be held ready (not providing energy) to meet the largest requirement. If a different facility is to provide response in each timeframe, it must also be held ready to inject in case of a contingency, increasing the total reserve held out of the energy market.

Where services are provided from the same cost base (in the case of Contingency Reserve, the costs of having 1 MW of capacity reserved and ready to respond), increasing the number of Contingency Reserve classes introduces potential for inefficient offer construction, opportunities for gaming, and increases the complexity of market power monitoring and control. Experience with ambiguity between costs recovered via the LFAS market and those recovered via Synergy portfolio dispatch illustrates the difficulty in monitoring costs shared across multiple markets. Each additional segment of reserve will also increase accreditation and compliance requirements for participants, and ongoing operational complexity for AEMO. This means that options with lower numbers of segments are likely to better support market power monitoring and mitigation and minimise the cost and complexity of operation of and participation in ESS.

Under the Taskforce's preferred approach, each type of facility can provide some level of service in all relevant Contingency Reserve timeframes. Additionally, their capability will match the shape of the required curve, and they will provide response from the same cost base in each time period. That means there is likely to be limited benefit in having different facilities providing different classes of reserve, and so further segmentation is unlikely to significantly change dispatch outcomes.

3.6.2 Potential for additional SFR requirement

The ESSFR noted that carrying additional SFR would operationally provide additional coverage to cater for small frequency disturbances within the contingency recovery timeframe to avoid UFLS events when reserves are fully depleted. However, it was also observed that this could be avoided within similar overall outcomes by:

- ensuring Regulation quantities are not counted as part of PFR quantities; and
- ensuring that PFR providers are, where practical, capable of responding to AGC commands to commence frequency recovery utilising any spare PFR quantity not fully utilised during the contingency.

As such, the Taskforce has concluded that an additional SFR requirement will not be necessary. This is consistent with the desire to minimise complexity in market design and overall costs of supply.

3.6.3 Taskforce Design Decisions – Contingency Reserve

1. Consistent with Technical Option T2, described in Table 1, the Contingency Reserve service should not be further segmented other than an upward and downward service, with this approach to be confirmed following completion of modelling by AEMO.
2. Regulation quantities will not be counted as part of Contingency Reserve provision.
3. Where practical, Contingency Reserve providers capable of responding to AGC signals will be used to assist in restoring system frequency back to 50 Hz.

3.7 Accreditation

When considering how different facilities respond to a frequency deviation, 1 MW of capacity reserved from a mid-merit coal unit is not necessarily equivalent to 1 MW of capacity reserved from a peaking gas turbine, or 1 MW reserved from an inverter connected storage device. This is due difference in response times (and rate of response), and is the case regardless of how many segments are implemented.

As part of accrediting facilities for provision of ESS, AEMO would identify the contribution to reserve needs in each segment made by 1 MW of capacity of that facility, under a variety of system conditions. The resulting ‘ESS contribution factor’ can then be used by the market clearing engine to account for differences in facility capability. Faster-responding units will have higher factors, and factors may vary across different system conditions (as specified when accredited). A similar approach is used in Singapore and PJM to ensure the clearing engine takes account of the different response capabilities of different facilities.

Given the evolving nature of the power system, AEMO will need to re-assess contribution factors on at least an annual basis, as well as reviewing actual responses following contingency events. Non-compliance with performance requirements would be reflected in a revised ESS contribution factor (along with any other applicable compliance actions). The detail of the method of accreditation will be specified in a market procedure, and AEMO will

endeavour to prescribe default ESS response curves (under different system conditions) in a manner that minimises volatility across the fleet – the closer the curves match capability, the less reserve will need to be carried.

3.7.1 Taskforce Design Decisions – Accreditation

1. AEMO will implement an accreditation mechanism for Contingency Response services that defines an ‘ESS Contribution Factor’ for use in co-optimisation to reflect the contribution of facilities with varying capabilities.
2. AEMO will periodically review the accreditation of facilities (at least annually) and revise parameters where necessary (e.g. following a contingency event).
3. The accreditation process for both Contingency Response and Regulation services will be described in a market procedure and be subject to the procedure review process.

3.8 Method for determining real-time requirements

Options to determine size of requirement largely flow from the segmentation approach and the ESSFR recommendations.

3.8.1 Frequency Regulation

The need for Regulation Service is driven by the level of accuracy of predictions for system outcomes over the next dispatch interval and the nature of dispatch in relation to predicted movement (e.g. variation between linear dispatch and dynamic load movement). This variability stems from:

- variability in intermittent generation;
- the difference between forecast and actual load, and variability of load in transitioning between dispatch cycles;
- scheduled generator deviation from dispatch targets; and
- deviation of generator ramping profiles from the load ramping profile.

Historically, a single LFAS requirement has been set for all intervals, while in practice the requirement may be lower or higher depending on system conditions.

Consistent with the recommendations of the ESSFR, the Regulation requirement for the new ESS framework will be more dynamic than at present. The initial requirement will be set based on historical usage – i.e. how much total deviation occurs within each dispatch interval – rather than analysis of the underlying drivers. Over time, the requirement for future time periods will be set based on historic performance in periods with similar characteristics (e.g. forecast load and generation levels/time of day).

AEMO is currently undertaking analysis to support the activities of the Taskforce to confirm how dynamically the requirement can be set. This analysis will also assess whether the overall

level of Regulation required will differ significantly from the amount of LFAS currently procured. At minimum, the Regulation requirement will retain the current peak / off-peak differentiation.

3.8.2 Taskforce Design Directions – Frequency Regulation

1. The Regulation requirement will be set to meet the requirements in the FOS, taking into account the:
 - a) variability of demand;
 - b) variability of intermittent sources;
 - c) inherent errors in dispatch; and
 - d) damping effects, such as available droop and system inertia.
2. The method of setting Regulation requirement will be described in a market procedure.
3. The method of setting regulation requirement will be reviewed within 12 months of five-minute dispatch intervals being introduced, and then as part of the regular ESS reviews.

3.8.3 Contingency Reserve

The amount of Contingency Reserve required in each interval depends on the:

- size (in MW) of the largest credible contingency (either largest single unit injection or multiple generating facilities lost in a single event);
- stored energy in the power system (inertia/synthetic inertia); and
- load relief available from the underlying system load or DER.

In the current WEM, the minimum spinning reserve (now referred to as Contingency Reserve) requirement is currently set at 70 per cent of the largest contingency. Because the service is managed manually, the actual quantum available at any time can be higher or lower.²⁹ The inclusion of ESS dispatch into the co-optimised clearing engine will mean that the required quantity is always met, and that over-procurement is minimised.

The ESSFR suggested that a more dynamic requirement be introduced, varying with the amount of system inertia, load relief from the underlying system demand, and the size of the largest single contingency (whether it be generation, network or load), and taking into account reasonable operational margins.

AEMO has developed an aggregate frequency response model that captures the relationships between these three factors, identifying the feasible solution space inside which the security

²⁹ See page 10 of AEMO's 2019 Ancillary Services Report <https://www.aemo.com.au/-/media/Files/Electricity/WEM/Data/System-Management-Reports/2018/2018-Ancillary-Services-Report.pdf>

of the power system is maintained.³⁰ This model can be used to determine the different requirements in different power system conditions.

Additional work remains to integrate this model with the co-optimised dispatch process, and further detail will be provided in the upcoming Taskforce information paper on ESS scheduling and dispatch.

3.8.4 Taskforce Design Decisions – Contingency Reserve

1. The required Contingency Reserve quantity will be set dynamically per interval by AEMO using co-optimisation and a frequency response model.
2. Quantities for Contingency Reserve (both PFR and RoCoF control) will be set to meet the requirements of the Frequency Operating Standard, taking into account:
 - a) the size of the largest credible contingency;
 - b) the availability and estimated quantity of load/DER relief;
 - c) the available system inertia on the power system; and
 - d) operating margins to minimise risk of inadvertent operation of underfrequency load shedding.
3. The method of setting Contingency Reserve and RoCoF Control Service requirements (including the market clearing engine formulation) will be described in a market procedure.

³⁰ See: <https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/Future-SWIS-requirements>

Appendix A - Terminology comparison for Frequency Control Services

Different terminology is used in the current WEM rules, the ESSFR and this paper to describe ESS. A comparison of this terminology is provided in this appendix. The terminology used to describe ESS in this paper will be retained in future Energy Transformation Taskforce papers on ESS.

Current Ancillary Services (WEM Rules)	System requirements (ESSFR)	Future Essential System Services (this paper)	
Load Following Ancillary Service	Frequency Regulation	Frequency Regulation	
Spinning Reserve Ancillary Service	Primary Frequency Response (raise) Secondary Frequency Response (raise)	Contingency Response	Contingency Reserve
Load Rejection Reserve	Primary Frequency Response (lower) Secondary Frequency Response (lower)		
N/A	Rate of Change of Frequency (RoCoF) Control		RoCoF Control