Renewable Integration Study Stage 1 Appendix B: Frequency control

March 2020

Important notice

PURPOSE

This is Appendix B to the Renewable Integration Study Stage 1 report, available at https://www.aemo.com.au/energy-systems/Major-publications/Renewable-Integration-Study-RIS.

DISCLAIMER

VERSION CONTROL

Version	Release date	Changes
1.0	30/4/2020	

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B1. Appendix B summary

B1.1 Changing system conditions and reserve requirements

Since the introduction of the frequency control ancillary services (FCAS) markets in 2001, a number of parameters fundamental to frequency control in the NEM have changed, and are projected to change further. The largest generating unit, which is the risk managed through raise contingency FCAS, has increased from 660 MW to a typical value of 750 MW. At the same time, system inertia has been declining, and this decline is expected to continue. Load relief, which dynamically supports frequency control, has also reduced, having a comparable effect to the decline in inertia.

Over the same period there has been a decline in the Primary Frequency Response (PFR) provided by generation in the NEM. This has reduced the power system's resilience to events and resulted in a lack of effective control of frequency in the NEM under normal operating conditions. A lack of consistency and certainty of PFR delivery from generation has impacted AEMO's ability to effectively model and plan the system, understand the cause of power system incidents, and design emergency frequency control schemes (EFCS). The implementation of the Mandatory PFR Rule change is currently underway to address this issue.

The Frequency Operating Standard (FOS) containment requirement has been met for all historical credible contingencies. Support from PFR delivered in addition to that procured through the FCAS markets, along with response at speeds greater than set by the Market Ancillary Service Specification (MASS), have played a part in reducing the frequency excursions for historical events.

AEMO has recently changed the load relief factor assumed when setting contingency FCAS procurement volumes in response to the changing system, to procure more FCAS. The forecast reduction in inertia out to 2025, combined with the decline in load relief, will mean that more, and/or faster, frequency sensitive reserve will be needed to ensure the FOS continues to be met for all credible events.

B1.2 Managing new types of risk

Distributed solar PV (DPV) behaviour, utility-scale inverter-based resources (IBR) behaviour, and run-back schemes are making the system more complex. These emerging issues are expected to further exacerbate rate of change of frequency (RoCoF) and worsen post-contingent outcomes for credible and non-credible events. The correct framework is needed to ensure frequency sensitive reserve coverage for these risks.

B1.3 Managing the transition to lower inertia

Revision of ancillary service arrangements will be required to ensure the speed and volume of PFR match the size of the Largest Credible Risk (LCR) and the frequency containment requirements for the range of expected future operating conditions.

No large power system currently operates without synchronous inertia, and a minimum level of synchronous inertia will be needed in 2025. A staged approach to operating at lower inertia is recommended to progressively manage the expansion in the operating envelope of the system. This will allow the system frequency control design to be adapted to the changing system, with capacity built in advance of the requirement becoming evident on the system.

This report proposes the introduction of an inertia safety net for system intact, that can be progressively lowered to facilitate a staged approach. The proposed inertia safety net for system intact would operate in parallel with the existing regional inertia requirements that are in place when there is a credible risk of islanding, or a region has been islanded. The existing and proposed inertia limits are given in Table 1.

Table 1 Existing and proposed inertia limits

<table>
<tr><th>System condition</th><th>Managed event</th><th>Inertia limit</th></tr>
<tr><td>System intact</td><td>Credible trip of Largest Credible Risk (single unit)</td><td>Mainland: This report recommends consideration of an initial inertia safety net in the range of 55,000 MWs to 65,000 MWs in the mainland, with staged reduction towards a minimum inertia available thorough system strength requirements (currently 45,350 MWs).
Tasmania: Minimum threshold level of inertia, or secure level of inertia is always applicable.</td></tr>
<tr><td>System intact</td><td>Non-credible separation event</td><td>Regional inertia and reserve levels to survive non-credible separations not generally defined. These types of events are subject to periodic review through the Power System Frequent Risk Review (PSFRR).</td></tr>
<tr><td>System intact</td><td>Credible or protected risk of separation</td><td>Defined as Minimum threshold level of inertia, calculated as per the Inertia Requirements and Shortfalls Methodology.
Current values:<table><tr><td>Queensland</td><td>12,800 MWs</td></tr><tr><td>New South Wales</td><td>10,000 MWs</td></tr><tr><td>Victoria</td><td>12,600 MWs</td></tr><tr><td>South Australia</td><td>4,400 MWs</td></tr><tr><td>Tasmania</td><td>3,200 MWs</td></tr></table></td></tr>
<tr><td>Islanded region following separation</td><td>Credible trip of Largest Credible Risk within islanded region</td><td>Defined as Secure operating level of inertia calculated as per the Inertia Requirements and Shortfalls Methodology.
Current values:<table><tr><td>Queensland</td><td>16,000 MWs</td></tr><tr><td>New South Wales</td><td>12,500 MWs</td></tr><tr><td>Victoria</td><td>15,400 MWs</td></tr><tr><td>South Australia</td><td>6,000 MWs</td></tr><tr><td>Tasmania</td><td>3,800 MWs</td></tr></table></td></tr>
</table>

B1.4 Summary of recommendations

Key challenges	Actions/Recommendations	Reference to this appendix	Reference to main report
There has been a decline in the PFR provided by generation in the NEM. This has reduced the power system's resilience to events at a time when events are becoming more complex and less predictable. It has also resulted in a lack of effective control of frequency in the NEM under normal operating conditions. A lack of consistency and certainty of PFR delivery from generation has impacted AEMO's ability to effectively model and plan the system, understand the cause of power system incidents, and design EFCS.	• Ensure near-universal PFR enablement across the generation fleet. This requirement is needed now, and will continue to be needed into the future, as an import component of maintaining and strengthening system resilience. This requirement should be part of any future regulatory framework.	• **Section B3.3** Changes to frequency control in the NEM • **Section B5.2** Non-credible separation events • **Section B6.1** PFR Rule change • **Section B6.7** Tools and models	**Action 4.1** In progress 2020-21. AEMO to facilitate implementation of the Mandatory PFR Rule change.
NEM inertia levels could drop by 35%. Historically, NEM mainland inertia has never been below 68,000 MWs. By 2025, inertia could drop to as low as 45,000 MWs. This will increase the required volume and/or speed of frequency sensitive reserve following a contingency event, and the power system will operate in configurations where the system dynamics are different to those experienced today. **DPV behaviour, IBR behaviour, and run-back schemes are making the system more complex.** These emerging issues will further exacerbate post-contingent outcomes for credible and non-credible events. Non-credible contingencies are expected are expected to result in higher RoCoF, the effect of which is not yet fully understood for the NEM.	• Revise ancillary service arrangements to ensure the required speed and volume of PFR match the size of the LCR and FOS containment requirements for the range of expected future operating conditions.	• **Section B4.** Credible events	**Action 4.2** AEMO to publish a detailed frequency control workplan in 2020 covering tasks and timeframes.
	• Rewarding of faster response should not reduce the overall volume of response below the required quantity.	• **Section B4.7** Frequency responsiveness of reserve	
	• Consider the correct management strategy for secondary risks and continue work in quantifying their impact. These risks may be managed through a combination of reducing the size of the overall risk or carrying additional reserve.	• **Section B4.9** Secondary risks • **Section B5** Non-credible events	
	• Investigate the introduction of a system inertia safety net for the mainland NEM, under system intact conditions. This minimum level safety net should be progressively revised as operational experience is built and additional measures are put in place to ensure system security. Investigation should include specifying the initial value and how the safety net will be maintained.	• **Section B6** Managing transition to lower inertia	

Key challenges	Actions/Recommendations	Reference to this appendix	Reference to main report
	• Investigate the effect of higher RoCoF on DPV, utility-scale generation, switched reserve providers, and protection relays used in various network functions. The result of this investigation will be a recommended system RoCoF limit, or set of RoCoF limits, in addition to existing generator ride-though requirements. Investigation should include assessment of the adequacy of EFCS, including UFLS, under decreasing levels of inertia.	• **Section B3.3** Changes to frequency control in the NEM • **Section B3.4** RoCoF and inertia limits • **Section B5.1** Changing nature of risk • **Section B6** Managing transition to lower inertia	
	• Continue investigation into DPV penetration into UFLS load blocks.	• **Section B5.1** Changing nature of risk	
	• Apply appropriate limits to the total proportion of switched reserve. This is needed to ensure there is a minimum amount of dynamic frequency control.	• **Section B4.8** Sensitivity to type of reserve	
	• Investigate appropriate regional contingency FCAS requirements, particularly for South Australia and Queensland.	• **Section B5** Non-credible events	
	• Update AEMO's existing system frequency model to be able to predict post-contingent frequency outcomes based on generating unit dispatch. Development of this model will benefit from the capture of high-speed generator output and network quantities on a routine or ongoing basis. • Consider developing the system frequency model into an online dynamic security assessment tool for frequency stability.	• **Section B4.2** Method • **Section B6.5** Further progression towards low inertia • **Section B6.7** Tools and models	

B2. Introduction

B2.1 Objectives of this study

This Appendix, which is part of AEMO's *Renewable Integration Study Stage 1 report*[1], focuses on the adequacy of existing frequency control arrangements out to 2025 in Australia's NEM.

The aim of this study is to identify, and where possible quantify, challenges associated with controlling system frequency at lower levels of system inertia and at higher penetrations of utility-scale IBR and DPV.

The key objectives are to:

- Assess the sufficiency of existing frequency control arrangements used to ensure frequency requirements are met for the loss of the LCR under projected system conditions to 2025.
- Identify appropriate system inertia limits for normal system operation.
- Identify changes to the risk profile of non-credible events under projected system conditions to 2025.
- Identify appropriate areas for further investigation with relation to transitional measures for managing frequency to 2025.

This report builds on the other work undertaken through the RIS Program, as detailed in the RIS Stage 1 report.

B2.2 Structure of this appendix

This appendix is structured as follows:

- **Section B3: Frequency control** – provides an overview of key concepts and context on how frequency control has changed in the NEM over time.
- **Section B4: Credible events** – covers how reserve is currently scheduled in the NEM and the projected reserve requirements at lower inertia. Factors that impact frequency control for credible events are investigated though dynamic simulations, including:
  - Load relief.
  - Size of the LCR.
  - Co-incidental trip of DER.
  - The speed of PFR.
  - The frequency sensitivity of reserve.
- **Section B5: Non-credible events** – provides qualitative information on the changing nature of non-credible events, discussing the impact of increasing system complexity and DPV with relation to

[1] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/future-grid/renewable-integration-study.

post-non-contingent outcomes, and outlining the uncertainty that exists around the maximum permissible RoCoF for the NEM.

- **Section B6: Managing transition to lower inertia** – outlines how a staged transition to lower levels of inertia would allow the required reserve qualities and capacity to be built in advance of the system needs, and uncertainties in system performance managed.
- **Section B7: Single Bus Model** – provides additional detail on the modelling used to study credible events.

B2.3 Exclusions and related work

Tasmania

This report focuses on the mainland NEM rather than Tasmania. Tasmania is a different system in terms of frequency control[2]. It has different FOS[3] requirements, and inertia and reserve have a number of differences in the way they are managed, including inertia sensitivity on FCAS constraints. There are more sophisticated frequency models available for Tasmania which allow for detailed study of frequency-related issues. As Tasmania is always under credible risk of islanding or already islanded, the Minimum Inertia Requirements methodology[4] goes a long way to addressing the issues examined in this report for a Tasmanian context.

Risk size

The use of intertrip schemes on multiple generators associated with the same transmission line could lead to larger single risks than those currently managed though the FCAS markets. This report assumes that these types of risks will be managed to keep the LCR at its current size, rather than managed through purchasing more FCAS.

Virtual inertial and fast frequency response

Although this report addresses some aspect of faster frequency response, it is not intended as a technological review of Fast Frequency Response (FFR) or synthetic and virtual inertia. AEMO has published or commissioned a range of additional material on FFR and synthetic inertia[5,6,7,8].

Frequency control in normal operation

AEMO is progressing work to better understand the impact of the variable nature of wind and solar generation on maintaining frequency under normal operating conditions. This work has been commissioned as part of the RIS program. AEMO has commissioned a set of other reports on frequency control within the Normal Operating Frequency Band (NOFB)[9,10].

[2] See https://www.aemo.com.au/Media-Centre/~/-/media/B47810C12E25473CB81968D5D4218F78.ashx.

[3] See https://www.aemc.gov.au/sites/default/files/content/c2716a96-e099-441d-9e46-8ac05d36f5a7/REL0065-The-Frequency-Operating-Standard-stage-one-final-for-publi.pdf.

[4] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[5] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/FFR-Working-Paper---Final.pdf.

[6] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf.

[7] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/FFR-Coversheet-2017-03-10a.pdf.

[8] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf.

[9] At https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf.

[10] At https://www.aemc.gov.au/sites/default/files/2019-08/International%20Expert%20Advice%20-%20Notes%20on%20frequency%20control.pdf.

Power System Frequency Risk Review

AEMO is in the process of undertaking the latest revision of the Power System Frequency Risk Review, due for publication later in 2020.

Improving frequency control

AEMO is progressing several actions to improve primary frequency control, including:

- Facilitating the implementation of the Mandatory PFR Rule change.
- Investigating regional contingency FCAS requirements.
- Consideration of appropriate limits to the proportion of switched FCAS.
- Further refinement of regulation FCAS tuning and volumes.
- Investigating minimum performance standard for regulation FCAS providers.
- Consideration of regional regulation FCAS requirements.

B3. Frequency control

This section provides an overview of key concepts and context on how frequency control has changed in the NEM over time.

Key insights

- Increase in the LCR, coupled with a decline in system inertia, load relief, and PFR, has changed the physical parameters underpinning reserve management.

B3.1 Primary Frequency Response (PFR)

PFR is when a generator measures the local frequency and adjusts its active power output in response. PFR is automatic; it is not driven by a centralised system of control and begins immediately after a frequency change beyond a specified level is detected.

At a system level, PFR is needed to arrest a change in frequency following a disturbance. Stable control of frequency relies on PFR, making PFR essential for power system security.

Switched reserve, or purposefully tripped load, may assist the PFR from generators in arresting a change in frequency following a disturbance.

Reserve refers to the headroom available for PFR to respond to a frequency disturbance. In the NEM, FCAS markets are used to set minimum reserve levels. The MASS[11] set a base speed of response for those participants selected under the market to provide reserve. In this report, 6-second reserve refers to a response equivalent to the fast FCAS service but may be provided independently of FCAS participation.

B3.2 System inertia

System inertia is provided by the aggregate rotating mass of all synchronous machines and motors that are directly coupled to the grid. Synchronous inertial response is the instantaneous transfer of energy from these machines to the grid in response to a change in grid frequency. The response is provided by the physical properties of the machine, and does not require control system interaction.

The response acts to limit the RoCoF. Under low RoCoF conditions, PFR has more time to respond than under high RoCoF conditions.

B3.3 Changes to frequency control in the NEM

When FCAS markets were introduced in the NEM in 2001, the largest generating unit was 660 MW, making the loss of this supply the LCR under normal system conditions. Since then, the LCR has increased and now

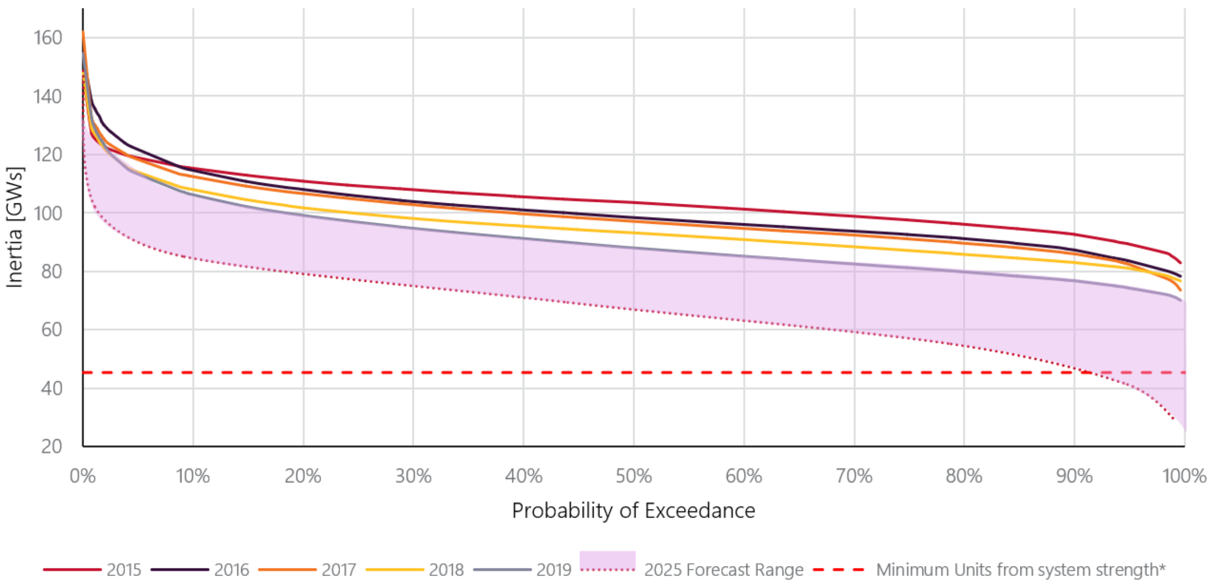
[11] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/market-ancillary-services-specification-and-fcas-verification-tool.

occasionally reaches 763 MW. As the largest single risk has increased, there have also been other changes to system parameters affecting frequency control.

Due to the displacement of synchronous machines, both through retirements and changes to dispatch patterns, the inertia on the power system has been progressively decreasing. The decline in inertia, coupled with the increase in risk size, results in higher instantaneous RoCoF values. With higher RoCoF, there is less time for PFR to respond to arrest the frequency following a contingency event.

Figure 1 shows historical inertia duration curves for the mainland NEM (excluding Tasmania) for 2015-19, and the range of forecast inertia to 2025[12].

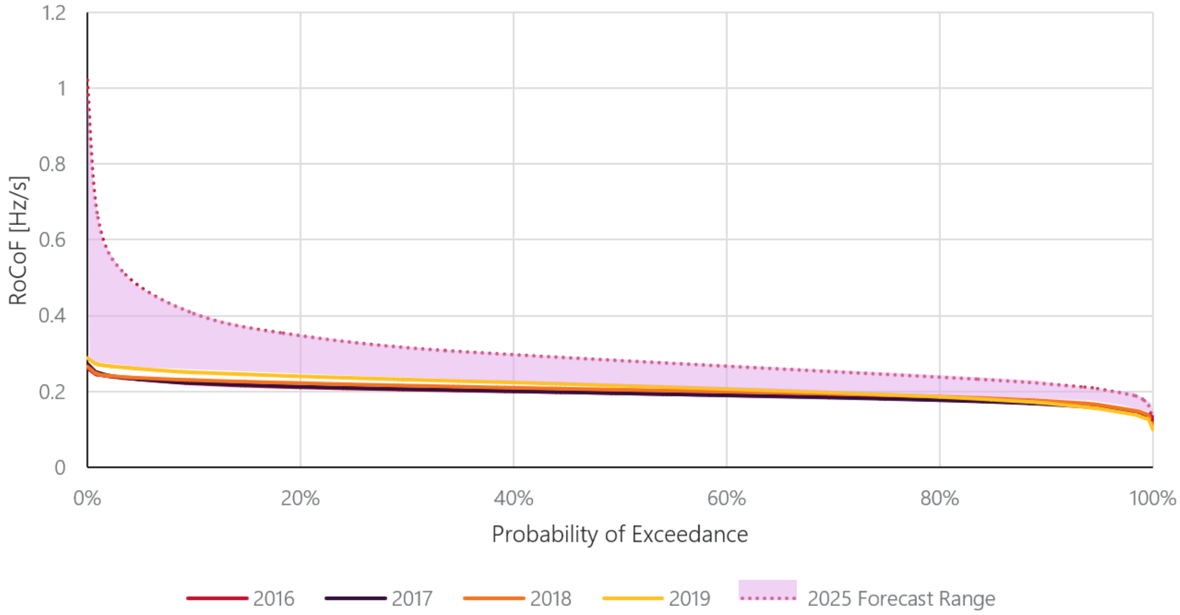
Figure 1 Mainland inertia duration curves, 2015-19 and forecast for 2025



The reduction in system inertia is reflected in the expected instantaneous RoCoF curves associated with the trip of the LCR (see Figure 2). For forecast values, the LCR has been selected as the generation of the single largest scheduled generating unit dispatched in the given interval. In some cases, the historical values of LCR may be larger than the single largest unit due to reclassification of other risks.

[12] The forecast range indicates the range of forecast modelling output using a variety of market dispatch assumptions out to 2025. The minimum extremity of this range is from the 2020 ISP Short Run Marginal Cost modelling, which can be expected to give a conservatively low forecast. The Minimum Units line represents the minimum inertia expected to be maintained through system strength requirements. The Probability of Exceedance means the statistical likelihood the forecast will be exceeded.

Figure 2 Instantaneous RoCoF duration curves, 2015-19 and forecast for 2025



Load relief on the system, often referred to as load damping or load sensitivity, has also changed[13]. Load relief is the change in load that occurs when power system frequency changes. It relates to how particular types of load, particularly motors, draw less power when frequency is lower and more power when frequency is higher.

This dynamic has a beneficial effect after an event by acting to damp frequency excursions and reduce the frequency nadir. As more motor load is connected through electronic interfaces, this factor can be expected to reduce, because the motor dynamics are no longer related to power consumption in the same way.

The provision of PFR in the NEM has been decreasing. Prior to the introduction of the FCAS markets in 2001, the power system was dominated by large synchronous generators, the majority of which provided PFR continuously, as required by the NER at the time[14]. With the removal of the requirement for PFR, it has been gradually withdrawn from the system, trending towards the volumes and nature of response procured through the FCAS markets. Utility-scale batteries, wind farms, solar farms, and Virtual Power Plant (VPPs) can contribute to supporting frequency through PFR. Batteries, wind farms, and VPPs now make up a portion of the FCAS provider pool.

The withdrawal of PFR has reduced the power system's resilience to events and resulted in a lack of effective control of frequency in the NEM under normal operating conditions. A lack of consistency and certainty of PFR delivery from generation has impacted AEMO's ability to effectively model and plan the system, understand the cause of power system incidents, and design EFCS[15]. The implementation of the Mandatory PFR Rule change is currently underway to address these issues[16].

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[13] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/2019/Update-on-Contingency-FCAS-Aug-2019.pdf.

[14] Clause 4.4.2(b) of version 1 of the NER. It is noted that the National Electricity Code, which preceded the NER, also contained clause S5.2.6.4, which specified provision of PFR outside a narrow deadband.

[15] See https://www.aemc.gov.au/sites/default/files/2019-08/Rule%20Change%20Proposal%20-%20Mandatory%20Frequency%20Response.pdf.

[16] See https://www.aemc.gov.au/sites/default/files/2019-08/Rule%20Change%20Proposal%20-%20Mandatory%20Frequency%20Response.pdf

B3.4 RoCoF and inertia limits

The *Managing the rate of change of power system frequency Rule*[17], put in place in 2017, requires that a base level of inertia is provided when there is a credible or protected risk of islanding part of the system, or during islanded conditions. Under the current NER, there is no base level of inertia required under normal operating conditions, or to ensure a resilient system response to non-credible events.

RoCoF is managed for select events in the NEM using constraint questions in the dispatch engine. Constraint equations control the size of the potential risk by reducing its MW value, rather than change the level of inertia. Flows on the Heywood interconnector are managed to limit RoCoF in South Australia to 3 Hz/s in the event of a non-credible separation, or 1 Hz/s in the event of a credible separation. The size of the largest single infeed is managed in Tasmania to avoid triggering UFLS on the RoCoF element.

There is no system limit for RoCoF, however the NER specify RoCoF ride-through requirements for generators under S5.2.5.3. The automatic access standard is to be able to operate continuously for RoCoF of 4 Hz/s for 0.25 seconds, and 3 Hz/s for more than one second. The minimum access standard is to be able to operate continuously for RoCoF of 2 Hz/s for 0.25 seconds, and 1 Hz/s for more than one second. There is no requirement for small-scale generation or network connected equipment more generally. The system RoCoF should be maintained within the range outside of which significant generation tripping is expected, with some margin.

[17] See https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque.

Table 2 Existing inertia and RoCoF management

<table>
<tr><th>System condition</th><th>Managed event</th><th>Inertia /RoCoF limit</th></tr>
<tr><td>System intact</td><td>Credible trip of Largest Credible Risk (single unit)</td><td>Tasmania: The size of the largest single infeed managed to avoid triggering under-frequency load shedding (UFLS) on the RoCoF element.

Mainland: Currently there is no base level of inertia required under normal operating conditions</td></tr>
<tr><td>System intact</td><td>Non-credible separation event</td><td>Tasmania: N/A

South Australia: Flows on the Heywood interconnector are managed to limit RoCoF in South Australia to 3 Hz/s in the event of a non-credible separation.

Rest of NEM: Regional inertia and reserve levels to survive non-credible separations not generally defined.

Procedure: Power System Frequent Risk Review (PSFRR) is a periodic review of power system frequency risks associated with non-credible contingency events and can include assessment of non-credible separations.</td></tr>
<tr><td>System intact</td><td>Credible or protected risk of separation</td><td>Defined as Minimum threshold level of inertia

Input assumptions:

Secure operating level of inertia less the inertia of the largest generating unit in the region.
Interconnector flows can be constrained to zero for credible risk of separation.
Tasmania is always under credible risk of islanding, unless islanded.

Current values:
<table>
<tr><td>Queensland</td><td>12,800 MWs</td></tr>
<tr><td>New South Wales</td><td>10,000 MWs</td></tr>
<tr><td>Victoria</td><td>12,600 MWs</td></tr>
<tr><td>South Australia</td><td>4,400 MWs</td></tr>
<tr><td>Tasmania</td><td>3,200 MWs</td></tr>
<tr><td>Mainland total</td><td>39,800 MWs</td></tr>
</table>
Procedure: Inertia Requirements and Shortfalls Methodology

South Australia: Flows on the Heywood Interconnector are managed to limit RoCoF in South Australia to 1 Hz/s in the event of a credible separation.</td></tr>
<tr><td>Islanded region following separation</td><td>Credible trip of Largest Credible Risk within islanded region</td><td>Defined as Secure operating level of inertia

Current values:
<table>
<tr><td>Queensland</td><td>16,000 MWs</td></tr>
<tr><td>New South Wales</td><td>12,500 MWs</td></tr>
<tr><td>Victoria</td><td>15,400 MWs</td></tr>
<tr><td>South Australia</td><td>6,000 MWs</td></tr>
<tr><td>Tasmania</td><td>3,800 MWs</td></tr>
<tr><td>Mainland total</td><td>49,900 MWs</td></tr>
</table>
Procedure: Inertia Requirements and Shortfalls Methodology</td></tr>
</table>

International approaches

Great Britain has a RoCoF limit of 0.125 Hz/s. This limit has been set to prevent embedded generation on the distribution system tripping[18].

EirGrid has a system RoCoF limit of 0.5 Hz/s, with an associated system inertia floor of 23,000 MWs[19]. EirGrid is undertaking a program of work that includes validating generators' ability to withstand higher RoCoF, with the aim of transitioning to a RoCoF limit of 1 Hz/s measured over 500 ms and associated inertia floor of 20,000 MWs. The planned transition will include trialling a decrease in the inertia floor.

ERCOT (Texas) has a defined critical inertia value of 100,000 MWs through dynamic simulations[20]. If the system inertia is below this level, frequency response from load resources may not respond in time to prevent UFLS from operating.

More information on international approaches to frequency management is provided in *Maintaining Power System Security with High Penetrations of Wind and Solar Generation: International insights for Australia*[18].

[18] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

[19] See http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-Programme-Transition-Plan-Q4-2018-Q4-2020-Final.pdf.

[20] See http://www.ercot.com/content/wcm/lists/144927/Inertia_Basic_Concepts_Impacts_On_ERCOT_v0.pdf.

B4. Credible events

This section covers how reserve is currently scheduled in the NEM and the projected 6-second reserve requirements at lower inertia. Factors that impact frequency control for credible events are investigated though dynamic simulations, including:

- Load relief.
- Size of the LCR.
- Co-incidental trip of DPV.
- The speed of PFR.
- The frequency sensitivity of reserve.

Key insights

- The **volume of contingency FCAS,** at the current performance requirements, would need to be increased to ensure the FOS is met for all credible events under the projected conditions. Under low inertia conditions, greater volumes of reserve are needed.
- As with volume and speed, control that is **continuously sensitive to frequency** is a required characteristic of PFR. The requirement for continuously responsive frequency control with droop limits the maximum proportion of switched reserve.
- **Faster PFR** can reduce the reserve requirement at lower inertia. The introduction of FFR requires system impacts beyond reserve management to be considered and managed.
- DPV trip or reduction due to voltage disturbances adds a **secondary risk**, that needs to be considered alongside the primary LCR.

B4.1 Loss of the largest generator

Raise contingency FCAS is procured to replace the active power lost should the LCR be tripped.

Kogan Creek Power Station is the single largest generating unit in the NEM, and has historically been the most common setting factor for the LCR in the NEM. More recently, the actual generation of Kogan Creek has on occasion reached 763 MW, however, a value of 750 MW is used as the risk for simulations because this is the most common generation value of Kogan Creek.

Internationally, some systems procure PFR to restore the frequency to a given level after it is arrested. Regulation FCAS and energy redispatch are responsible for frequency restoration in the NEM.

B4.2 Method

A single-bus root mean square (RMS) power system model for the NEM has been used to assess the impact of credible contingency events under system intact conditions as the amount of system inertia has decreased.

The loss of the largest generator has been simulated, and the modelled frequency compared to the 49.5 Hz frequency containment requirements under the FOS[21].

The study details the relationship between inertia and the quality and quantity of PFR. The 6-second FCAS requirements under the existing MASS[22] have been used to set the base level of PFR performance. The existing practices for setting reserve volumes were used to provide a reference point when projecting the volumes of reserve required.

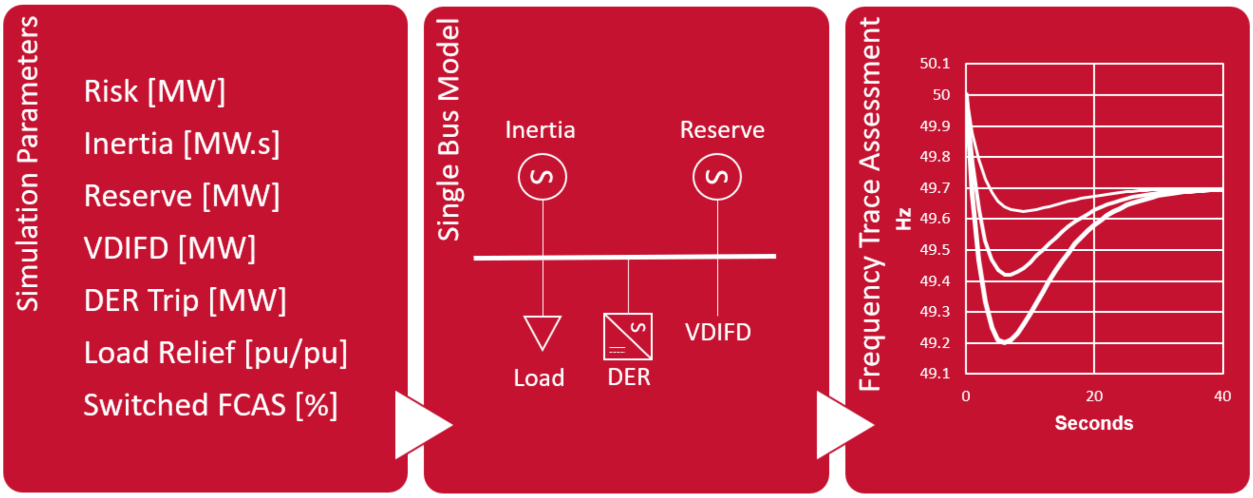
Sensitivity studies on the type of reserve scheduled, as well as the impact of secondary risks, are provided. Secondary risks are disturbances to the power balance that may happen alongside the primary risk. In this study, the loss of a large generator is considered as the primary risk. The secondary risks considered are the trip of DPV and Voltage Dip-Induced Frequency Deviation (VDIFD) that may occur in conjunction with loss of the primary risk.

Modelling

The single-bus RMS power system model for the NEM has been built in PSSE.

The simplified model consists of a lumped governor model, lumped load model, and under-frequency relay armed load to represent switched contingency FCAS. The model also allows DPV to be disconnected and the impact of VDIFD to be estimated. An overview of the modelling method is given in Figure 3, with additional detail provided in Section B7.

Figure 3 Modelling approach



Modelling limitations

The modelling approach used a lumped governor model, weighted towards the responsiveness of the large thermal FCAS providing generators, to represent all PFR in the NEM. Different technologies have different frequency response capabilities, and the responsiveness of generators can vary between different units of the same technology. The response of a single unit may also change based on its dispatch.

A more accurate method of modelling a power system's response to a power imbalance is to model each generating unit individually, providing the dispatch pattern of interest. System parameters, such as load response, can then be progressively refined over time through a continuous process of model validation.

[21] See https://www.aemc.gov.au/sites/default/files/content/c2716a96-e099-441d-9e46-8ac05d36f5a7/REL0065-The-Frequency-Operating-Standard-stage-one-final-for-publi.pdf.

[22] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Market-Ancillary-Service-Specification-V50--effective-30-July-2017.pdf.

A suitable aggregate system frequency model of the mainland NEM, incorporating individual generator models, is not available at this time. The lumped model approach can produce indicative information about system performance, however it is not suited to the accurate simulation of any given event.

Load data

High load and low load scenarios were selected from 2025-26 demand forecasts. The dynamic modelling has been run using 10% and 90% probability of exceedance (POE) forecasts for native demand[23], given in Table 3.

Table 3 Demand value modelling input

Scenario	Native demand (MW)	Operational demand (MW)
High load (10% POE)	28,107	25,695
Low load (90% POE)	18,860	17,933

Inertia-reserve charts

Results have been presented as a plot of the 6-second reserve to arrest the frequency within the FOS requirement against the level of system inertia. This form of presentation has been used in Western Australia's South West Interconnected System (SWIS)[24] and in the Finkel Review[25].

The presentation of the reserve requirement should not be mistaken as a minimum acceptable quantity of PFR, or frequency control enablement. The reserve requirement relates to the quantity of reserve, of an assumed performance, that is needed to meet one set of criteria for an assumed risk. The frequency control needs of the power system are broader than this and are best met by PFR enablement on all generating resources, as far as is practical [26], in conjunction with the reservation of headroom. The contingency FCAS markets are responsible for the reservation of headroom in the NEM.

Static requirement

The static requirement is the size of the LCR less the expected load relief.

When the active power lost during an event is replaced by an equal amount of active power, the frequency decline will be arrested. The static reserve requirement is the amount of active power required to replace the loss of the LCR. This value takes into account the expected load relief for a frequency deviation down to 49.5 Hz. The volume of contingency FCAS procured under the existing market arrangements is equal to the static requirement. The level at which frequency is arrested depends on when the replacement power fully substitutes the active power lost. The slower the response, the further the frequency is allowed to decline.

As the static requirement takes into account load relief, more reserve is procured at low load.

B4.3 Inertia-reserve charts for the loss of Kogan Creek

The inertia-reserve charts for the loss of Kogan Creek for high and low load are given in Figure 4 and Figure 5. The charts show an increasing 6-second reserve requirement at lower levels of inertia as active power is required more quickly to arrest the frequency before it reaches 49.5 Hz. The volume of active power needed remains the same, however more 6-second reserve is being scheduled to achieve power balance sooner. The static requirement is provided for reference.

[23] For demand definitions, see AEMO, *Demand Terms in EMMS Data Model*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

[24] See https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Contingency-Frequency-Response-in-the-SWIS.pdf.

[25] See https://www.energy.gov.au/sites/default/files/independent-review-future-nem-power-system-security-assessment.pdf.

[26] Notes on Frequency Control for the Australian Energy Market Operator, J. Undrill, at https://www.aemc.gov.au/sites/default/files/2019-08/International%20Expert%20Advice%20-%20Notes%20on%20frequency%20control.pdf.

Figure 4 Reserve requirement for the loss of Kogan Creek (high load)

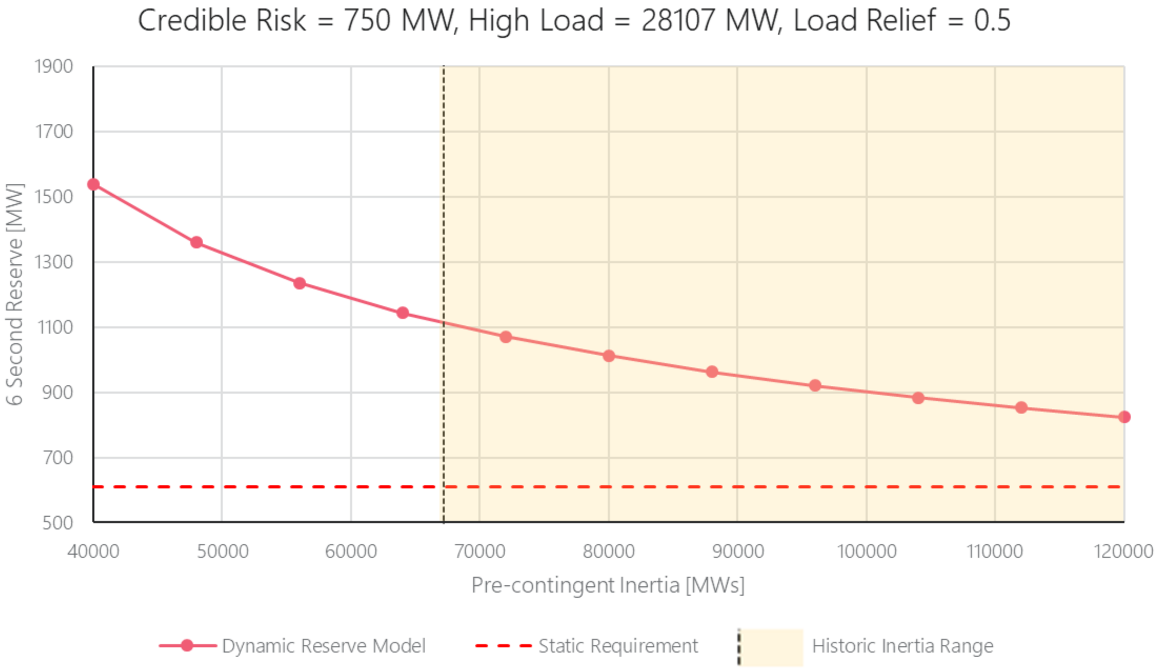
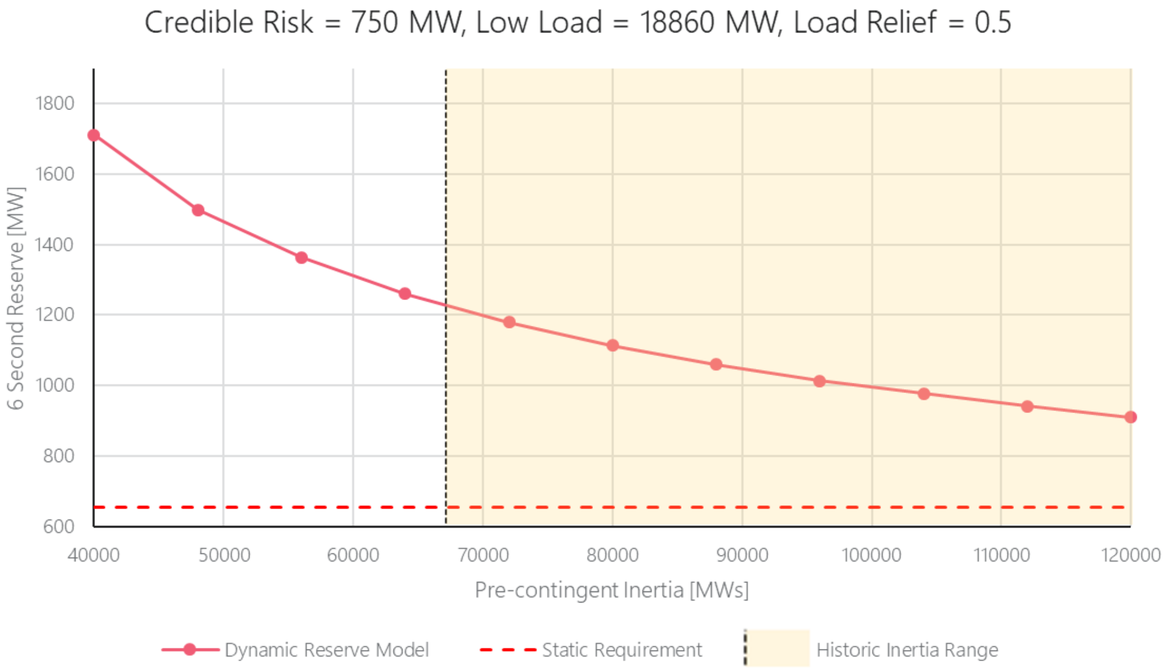


Figure 5 Reserve requirement for the loss of Kogan Creek (low load)



B4.3.1 Gap between the current level of reserve procurement and the reserve requirement

Figure 4 and Figure 5 show a gap between the modelled 6-second reserve requirement and the amount currently procured though FCAS (static requirement). This gap is larger under low inertia. The reserve requirement curve is weighted towards the responsiveness of the large thermal FCAS providing generators, to represent all PFR in the NEM. This is illustrative of the required increase of frequency sensitive reserve at a base speed of provision, but in practice this will vary depending on the aggregate PFR capability of the units dispatched.

Although declining, the PFR supplied by generators outside of FCAS markets is still significant and fills a portion of this gap. Some of the reserve will also be faster than the baseline dynamic model, as discussed in Section B4.8; this will reduce the reserve requirement. Reserve procured for the slow raise service, from units not selected in the fast market, may provide additional support up to six seconds. While the additional support from frequency response outside of the FCAS markets depends on dispatch, as well as what providers are selected, the combined effect has meant the total reserve provision has been adequate for the FOS containment requirement to be met for all historical credible contingencies.

The historical approach for securing the NEM for the loss of the LCR has been to purchase the FCAS required, without knowledge or expectation of any other PFR. As the parameters underpinning frequency control have changed over time, some response outside of the FCAS market, or above market specifications, has assisted in meeting the containment requirements for credible events. The amount of PFR available outside of FCAS markets is variable and AEMO does not have good visibility of the amount or quality of this response unless an event occurs, so the additional availability at any given time is difficult to determine with a high degree of accuracy.

Incorporating some explicit allowance for PFR outside of FCAS markets into the procurement volumes is plausible, although it would be a significant departure from the current approach. There are firm requirements placed on FCAS providers that do not apply to other PFR provision, so reliance on it would require additional risks be managed. Currently, there is insufficient monitoring of PFR provision outside of FCAS enablement, or tools such as online dynamic security assessment of frequency stability to quantify its impact across all dispatch intervals to a high degree of accuracy. Even if an allowance for additional PFR was made in the scheduling of FCAS, at times of low reserve the total amount of PFR would be expected to trend towards the amount made available through FCAS. This is when FCAS markets play their primary role in making headroom available for frequency response.

AEMO is not currently considering reducing FCAS procurement volumes below existing levels by taking PFR outside of FCAS markets into account, and has recently increased FCAS volumes[27]. Regardless of developments in the level of PFR available outside of FCAS, ancillary service arrangements will need to be revised so they ensure the FOS is met at projected levels of inertia when the reserve requirement is higher.

B4.3.2 Frequency traces for the loss of Kogan Creek

The system frequency in response to the same event at high and low load are shown in Figure 6 and Figure 7.

In these traces, the reserve has been set at the static requirement, or the volume of contingency FCAS that would be procured under the existing market arrangements. Traces are given for varying levels of inertia. The MASS standard frequency ramp is also show for reference.

The static requirement, at the response speed modelled, is insufficient by itself to arrest the frequency at 49.5 Hz. The nadir approaches 49 Hz as system inertia approaches 40,000 MWs.

[27] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/2019/Update-on-Contingency-FCAS-Aug-2019.pdf.

Figure 6 System frequency for the loss of Kogan Creek (high load)

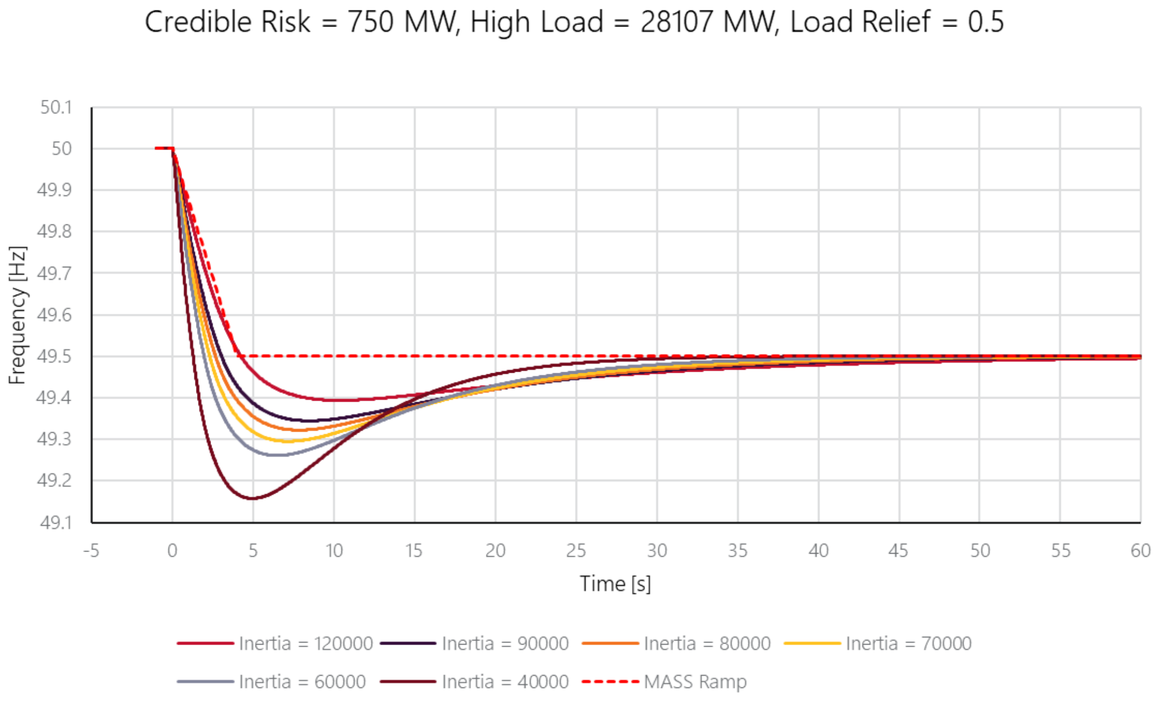
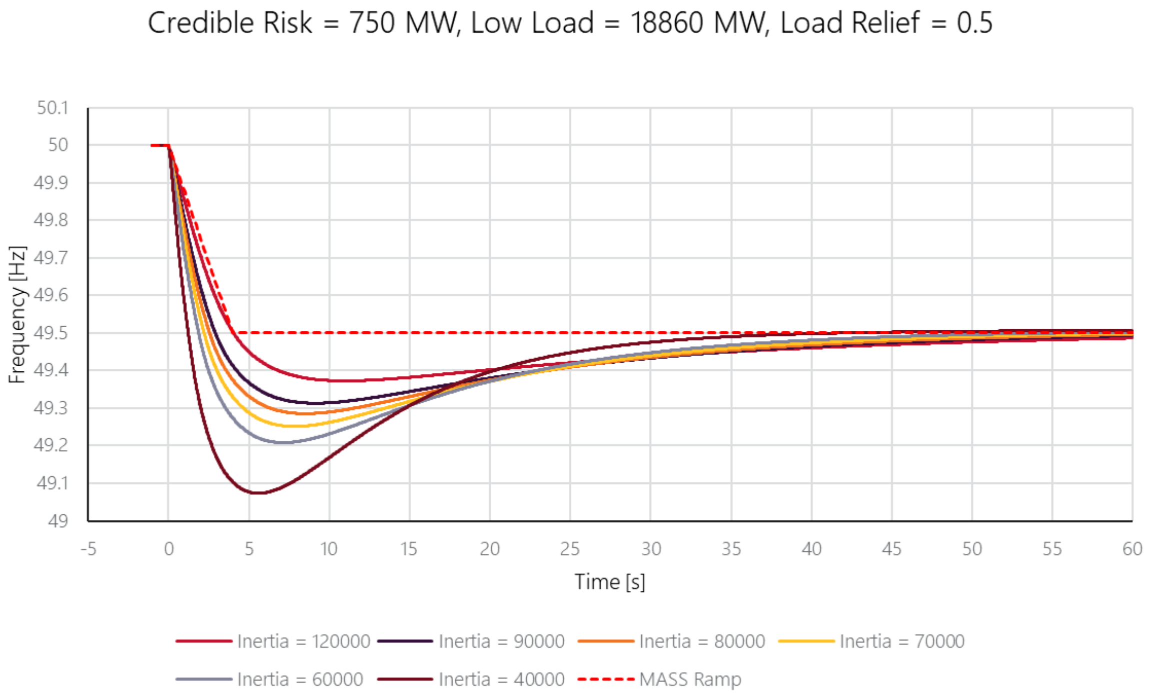


Figure 7 System frequency for the loss of Kogan Creek (low load)



B4.4 Sensitivity to load relief

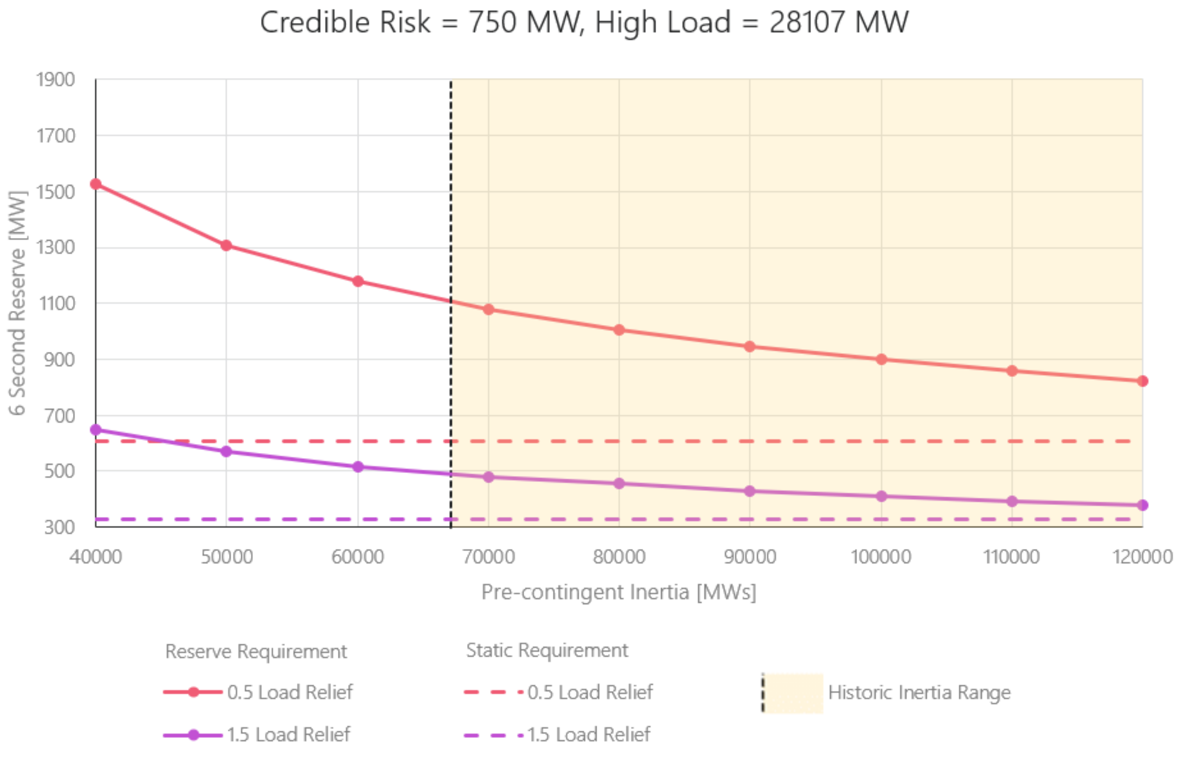
Load relief is the change in load that occurs when power system frequency changes. The mainland load relief factor has historically been modelled as 1.5. This means that for a 1% change in frequency (0.5 Hz), the total mainland demand is assumed to change by 1.5%. As more motor load is connected through electronic interfaces, this factor can be expected to reduce, because the motor dynamics are no longer related to power consumption in the same way.

In September 2019, AEMO changed the amount of load relief assumed when calculating the volumes of required contingency FCAS from 1.5 to 0.5, with the change being progressively introduced[28]. Load relief affects the dynamic frequency performance of the system. Following a generator trip, the frequency will decline. The load reduces in response to the frequency, slowing decline as well as reducing the frequency nadir. The lower the load relief factor, the faster the frequency will fall and so the faster the PFR response needs to be.

Studies from the United States have found that changes to the load response are as significant to system frequency performance as the impact of inertia changes[29]. This level of impact on reserve management is also evident in the NEM. The increase in assumed load relief used in FCAS procurement resulted in an increase in the static level of reserve. There is also a dynamic requirement, on top of the static reserve requirement that increases under low load relief, particularly when coupled with lower inertia. Unlike inertia, the level of load relief cannot be managed by changing system dispatch.

The effect of varying the load relief factor can be seen for high and low load in Figure 8 and Figure 9. The change in load relief changes the static reserve requirement, and so the volume of contingency FCAS that would be procured under the existing market arrangements. The dynamic effect of load relief can be seen in the widening margin between the static requirement and the reserve requirement as inertia is reduced.

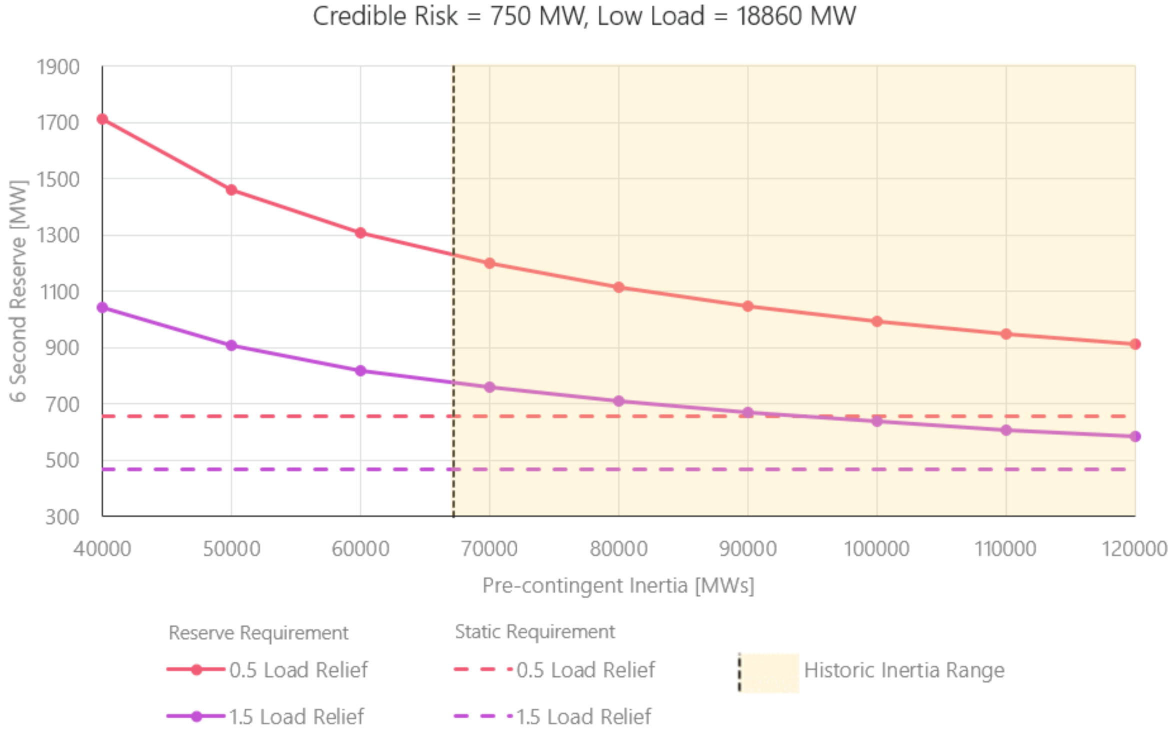
Figure 8 Reserve requirement sensitivity to load relief at high load



[28] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/2019/Update-on-Contingency-FCAS-Aug-2019.pdf.

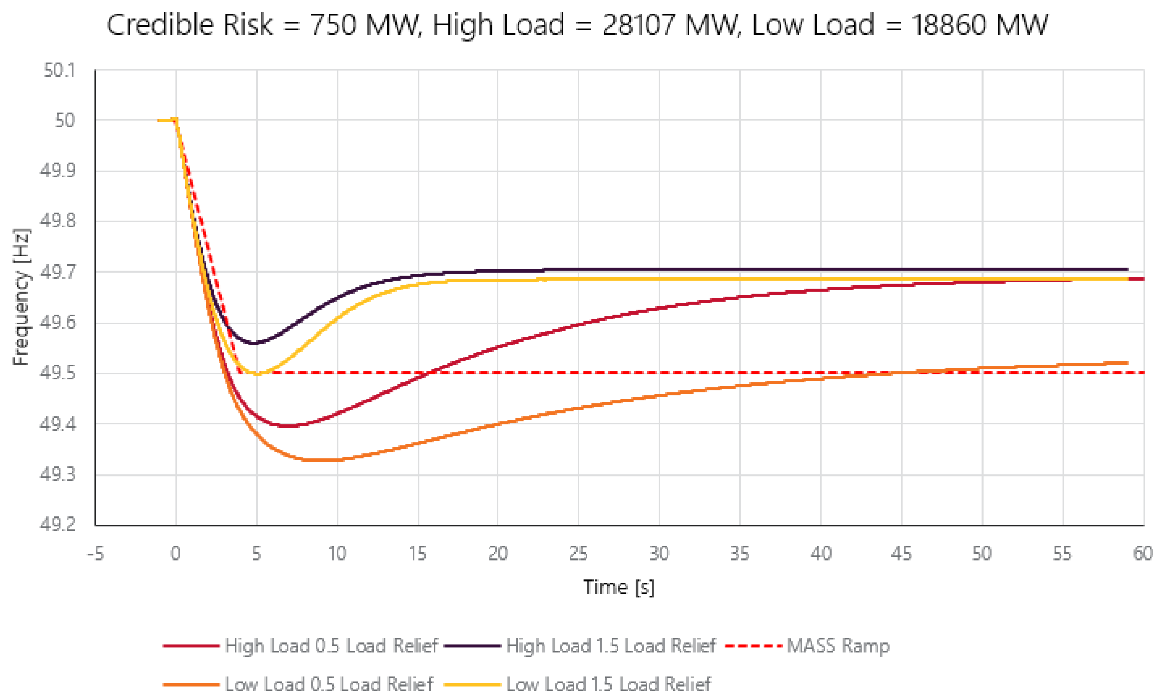
[29] *Primary Frequency Response and Control of Power System Frequency*, J. Undrill, at https://www.ferc.gov/industries/electric/indus-act/reliability/frequency-control-requirements/primary-response.pdf.

Figure 9 Reserve requirement sensitivity to load relief at low load



The impact of load relief on the frequency trajectory following a contingency event is shown in Figure 10. For the purpose of comparison, high and low load traces are shown with the same amount of reserve.

Figure 10 Load relief sensitivity frequency traces at same system inertia (80,000 MWs) and reserve (656 MW)



B4.5 Impact of the size of the LCR

To show the impact of the size of the LCR, five different sized risks were simulated.

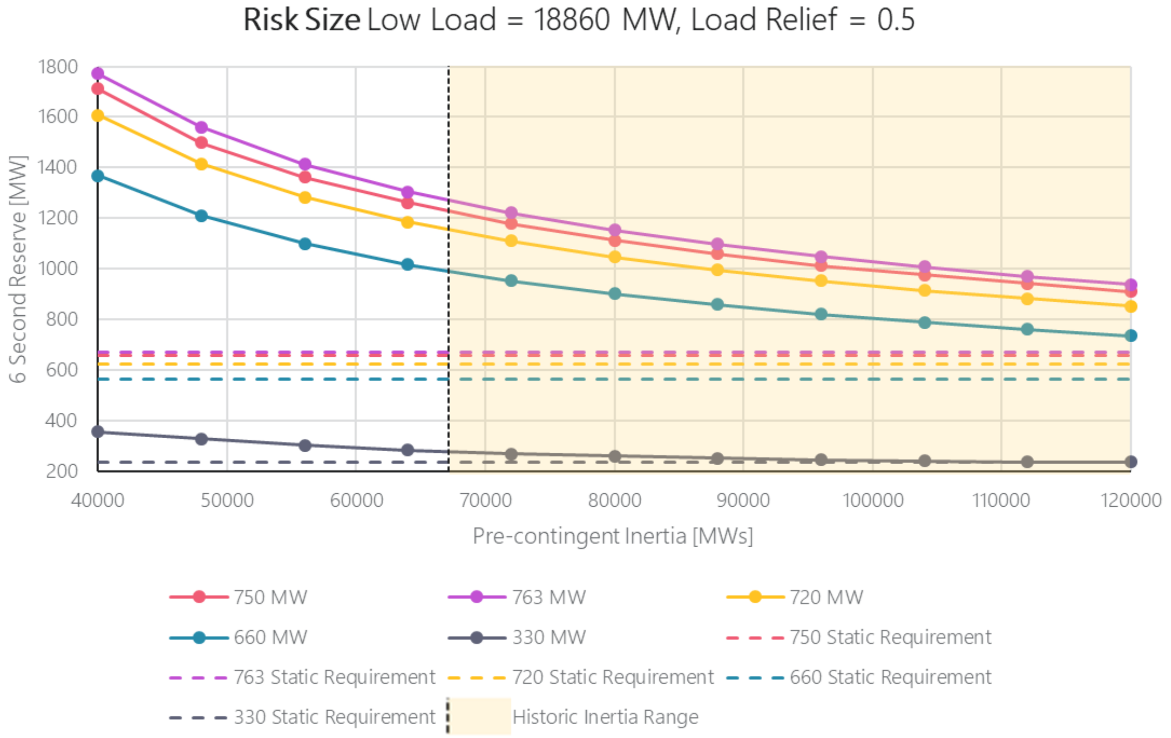
A risk of 763 MW and 750 MW is representative of Kogan Creek at its maximum value and its more typical output. The next largest unit in the NEM is Eraring at 720 MW.

AEMO has also simulated 660 MW and 330 MW risks; 660 MW represents one of several large New South Wales generating units, and 330 MW represents a large New South Wales generating unit at half output, or one of a number of Victorian brown coal units operating in the range of their minimum output.

For the 720 MW, 660 MW, and 330 MW simulations, a contingent inertia value for Eraring or the New South Wales 660 MW fleet has been used, rather than the value for Kogan Creek.

The comparison of reserve requirements is given in Figure 11.

Figure 11 Reserve requirements for different risk sizes



The initial post-event RoCoF is dependent on the size of the risk and inertia. This means that an increase in risk size will result in a greater increase in the reserve requirement at low inertia than at high inertia. This dynamic should be considered if the size of the LCR was to be increased above its existing maximum.

For the 330 MW risk, the static requirement meets the FOS containment criteria at higher inertia, at the speed of reserve modelled.

B4.6 Combined effect of changes on nadir time

A number of parameters underpinning the design of the FCAS markets were based on the system characteristics at the time. These include the size of the largest generating unit, load relief values, and inertia conditions. These parameters affect nadir time, or the time to reach nadir from when the event occurs. With the current LCR, under lower inertia and lower load relief conditions, the nadir times occur earlier.

For historical nadir times, the static reserve requirement is much closer to the total reserve requirement. As the nadir time becomes faster, the additional dynamic reserve requirement becomes more prevalent. The recent change in assumed load relief is a large part of this additional requirement.

Figure 12 System configuration impact on nadir times

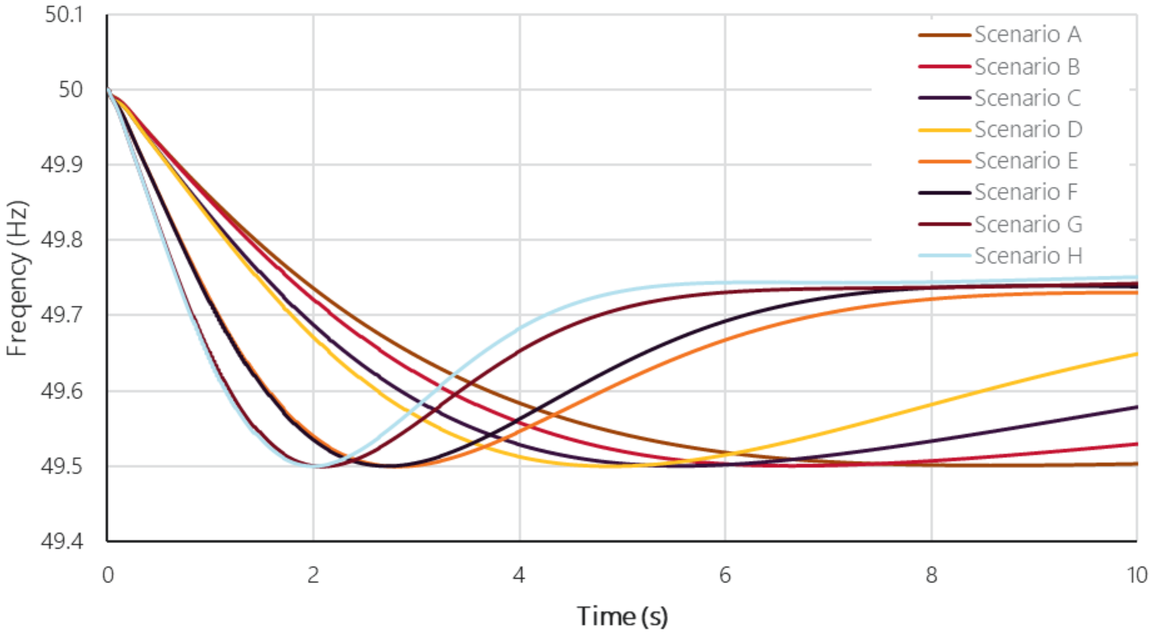


Table 4 Nadir time scenarios

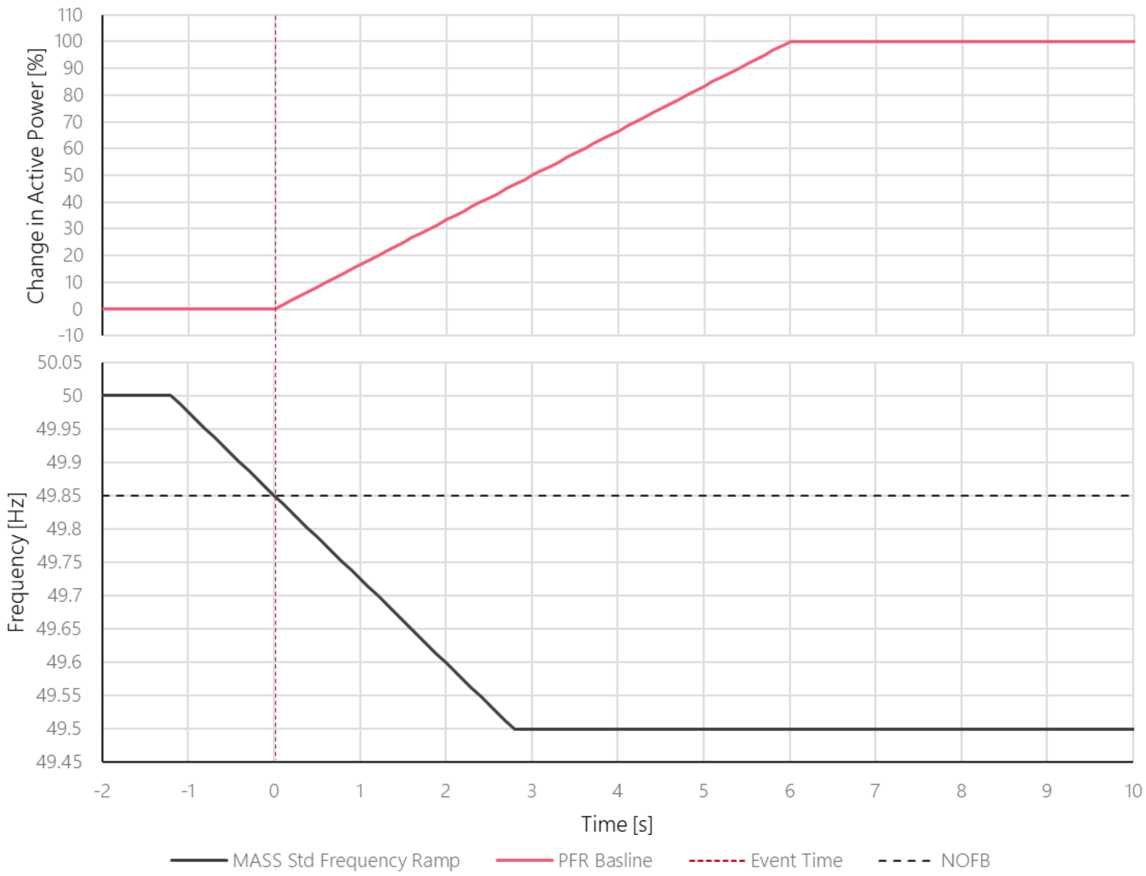
Scenario	Risk (MW)	Required 6s Reserve (MW)	Inertia (MW.s)	Load (MW)	Load Relief	Nadir Time (s)
A	660	271.62	100,000	28,107	1.5	8.61
B	660	477.09	100,000	28,107	1	6.65
C	750	640.65	100,000	28,107	1	5.56
D	750	895.2	100,000	28,107	0.5	4.88
E	750	1,168.71	60,000	28,107	0.5	2.82
F	750	1,302.93	60,000	18,860	0.5	2.69
G	750	1,394.14	45,350	28,107	0.5	2.06
H	750	1,562.63	45,350	18,860	0.5	1.97

B4.7 Frequency responsiveness of reserve

Under current market arrangements, fast contingency FCAS is measured at six seconds. In valuing PFR, the MASS uses a standard frequency ramp. In response to this ramp, the MASS sets a baseline PFR response that is a straight line increasing in active power from the time the frequency crosses the NOFB up to the maximum response six seconds after the NOFB crossing time. The standard frequency ramp and baseline response are shown in Figure 13.

If a generator's measured PFR tracks the baseline response, its registered FCAS value will be its change in output achieved by six seconds. If the measured response is on average below this baseline response, its registered FCAS value will be less than the instantaneous 6-second value. If the measured response is on average above the baseline response, its registered FCAS value will be more.

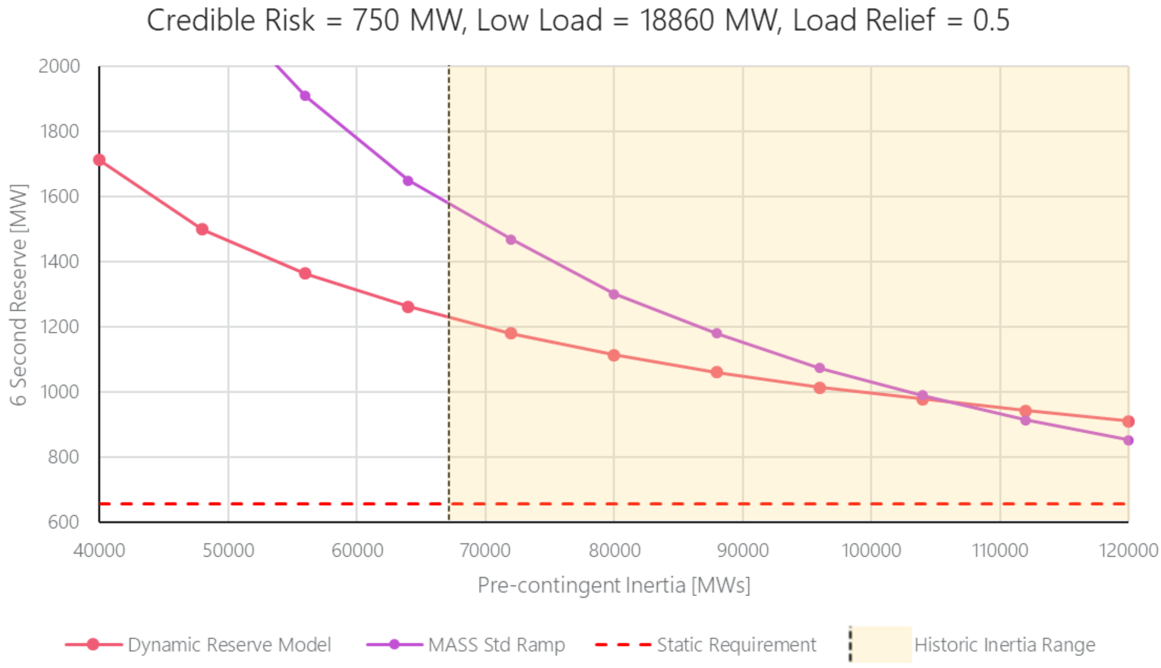
Figure 13 MASS standard under-frequency ramp used to assess raise services



The dynamic lumped model is sensitive to frequency, so if frequency is falling faster, it will respond faster, limited only by the time constants associated with the plant. In contrast, the PFR baseline represents a minimum FCAS performance under the MASS. Its speed is set with reference to one specific frequency profile. The behaviour of the plant for faster or slower frequency excursions is not specified by the MASS. The response of the dynamic lumped model has been compared to the baseline MASS response in Figure 14.

The baseline MASS response is modelled by injecting active power, as shown in Figure 13, starting from when the system frequency crosses 49.85 Hz. This is achieved in PSSE by changing the active power value of a negative load.

Figure 14 Dynamic model response compared to MASS baseline requirement



Some FCAS providers, including conventional machines and IBR, have their plant set to cap or match their FCAS provision to the MASS baseline PFR response, or another fixed profile. As shown in Figure 13, this will slow the speed of response under low inertia conditions and result in greater reserve requirements. This also has implications for modelling and planning of the system. Historically, governors of synchronous machines have been modelled to give the aggregate system PFR. Where complex secondary controllers are driving the response to a large extent, modelling of governors in standard power system modelling packages will no longer result in a representative view of the system.

Removing frequency responsiveness from output completely, by forcing a generator to track a static profile, would have a detrimental impact on system behaviour if adopted widely. Historically, droop control has been applied to governor response so that all generators share the response to a frequency disturbance. By facilitating this sharing, droop control prevents generators responding too aggressively creating adverse interactions between each other. It also prevents over provision in the case of small imbalances.

The MASS should be applied as an overlay to the PFR of a provider, to evaluate the FCAS value of that response. It is not suited as a design guide for setting control parameters of plant. AEMO has drafted a Primary Frequency Response Requirement (PFRR)[30] as part of the Mandatory PFR Rule change. This requirement describes some of the control system design requirements for PFR including frequency responsiveness and droop control.

The extent to which the dynamic model shows lower reserve requirements than the MASS representative ramp model depends on the time constants modelled. In reality, the time constants of individual generators will vary, so the response of the system will vary depending on dispatch.

B4.8 Sensitivity to type of reserve

B4.8.1 Faster reserve

The speed of PFR is a continuum across technologies and individual plants. Batteries, and IBR more generally, represent the faster end of this range.

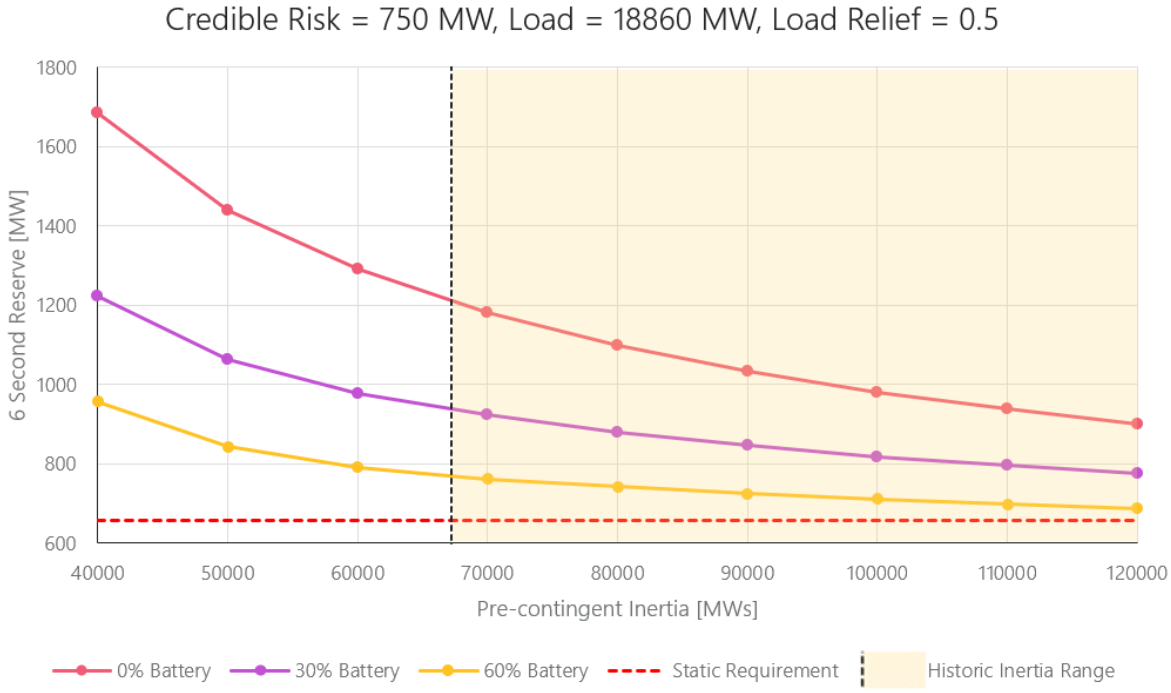
[30] See https://www.aemc.gov.au/sites/default/files/2019-10/AEMO%20-%20Primary%20frequency%20response%20requirements%20V1.1%20-%20clean.PDF.

To simulate the impacts of faster response, a frequency sensitive battery model was introduced into the single bus model.

The battery model has been set with an aggressive droop setting (1.7%) and a ±0.15 Hz deadband. The magnitude of the response has been capped at the value that would be produced for the injection of a MASS standard under-frequency ramp. The control parameters allocated to technologies with faster capabilities are as important to the response as the technology itself. For example, if a battery has been configured to track a baseline MASS ramp profile, it will have a response roughly equivalent to a large thermal generating unit.

Figure 15 shows that a higher proportion of faster reserve reduces the total amount of reserve required.

Figure 15 Reserve requirement for loss of Kogan with increasing proportions of faster reserve



B4.8.2 Trading off inertia with faster frequency response

Faster frequency response allows the power system to operate at lower levels of synchronous inertia, however no large power system operates today without synchronous inertia. Replacing synchronous inertia with fast acting control action may result in a system with very different system dynamics, not evident in a single bus RMS model. In the medium term, some level of synchronous inertia will be required[31,32]. In GE Energy Consulting's 2017 report *Technology Capabilities for Fast Frequency Response*[33], commissioned by AEMO, it was recommended that AEMO consider maintaining a minimum level of inertia, because this would have other benefits beyond frequency control, including in the areas of transient and voltage stability.

B4.8.3 Limitations to Fast Frequency Response

Introduction of rapid responses in the order of hundreds of milliseconds, often termed FFR, brings its own challenges. International studies into the design of wide area monitoring and control systems utilising FFR have found that if delivered in the wrong location it can affect angular separation between regions, increasing

[31] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/FFR-Working-Paper---Final.pdf.

[32] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/FFR-Coversheet-2017-03-10a.pdf.

[33] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf.

the risk of regional separation[34,35]. There are potentially other considerations for high locational concentrations of FFR including local voltage management, coordination with UFLS/OFGS, and interaction with SPSs.

National Grid (Great Britain) developed the Enhanced Frequency Response (EFR) product, which requires providers to respond in one second or less. The tenders were limited to a maximum size of 50 MW to remove grid code concerns[36], but also allowed a wider range of projects to tender. The technical requirements for the service specified a droop envelope and maximum ramp rates[37]. National Grid has undertaken a process of rationalisation of its frequency services and EFR is no longer being actively procured[38].

Droop settings facilitate the sharing of frequency response between providers in response to a frequency event. They allow each unit to respond in accordance with their size, with the overall response being distributed between providers. Batteries are capable of setting very low droop values, giving large responses to small changes in frequency. Internationally, minimum droop values, or maximum reactivity, are specified in grid codes in the range of 2-3%[39]. There is long-standing international experience with droop settings in this range. As the droop setting approaches 0%, or isochronous control, the provider would potentially swing its full capacity in response to any frequency disturbance within its band of frequency sensitivity. Wide adoption of very low droop settings has potential stability implications[40]. AEMO has set a minimum droop setting of 1.7% for battery providers of FCAS[41], unless otherwise specified.

B4.8.4 Switched reserve

While the provision of contingency FCAS has historically been through governor control from synchronous generators, an increasing amount of FCAS with switching controllers is being introduced. These providers are generally large or aggregated loads that can be partially or fully switched off in response to low frequency events, so the majority of switched FCAS providers participate in raise services. These switched loads are tripped when local frequency at the connection point breaches their under-frequency trip setting. In the NEM mainland, under-frequency trip settings are allocated at five levels between 49.8 and 49.6 Hz.

Figure 16 shows an upward trend in the switched proportion of fast FCAS dispatched in each dispatch interval calculated on a monthly basis. While the maximum proportions in each month appears similar, there is an increasing number of intervals where there is a high proportion of switched FCAS, trending to an average proportion of 30%.

Figure 17 shows that a higher proportion of switched reserve reduces the amount of reserve needed under lower inertia conditions. This is because the switched reserve is faster than the lumped dynamic model and so arrests the frequency decline sooner. For simplicity, the modelled switched FCAS is allocated evenly across the five trip settings between 49.8 Hz and 49.6 Hz.

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34 See https://www.nationalgrideso.com/document/144441/download.

35 Icelandic Operational Experience of Synchrophasor-based Fast Frequency Response and Islanding Defence, CIGRE C2-123 2018.

36 See https://www.nationalgrid.com/sites/default/files/documents/Enhanced%20Frequency%20Response%20FAQs%20v5.0_.pdf.

37 See https://www.nationalgrideso.com/sites/eso/files/documents/EFR%20Testing%20Guidance%20VD3%20%28Final%29.pdf.

38 See https://www.nationalgrideso.com/sites/eso/files/documents/Product%20Roadmap%20for%20Frequency%20Response%20and%20Reserve.pdf.

39 See https://certs.lbl.gov/sites/default/files/international_grid_codes_lbnl-2001104.pdf.

40 For example, see '*Impact of Frequency-Watt Control on the Dynamics of a High DER Penetration Power System*', Dinesh Pattabiraman et al, 2018 IEEE Power & Energy Society General Meeting (PESGM).

41 See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf.

Figure 16 Historical trend in dispatched fast raise FCAS

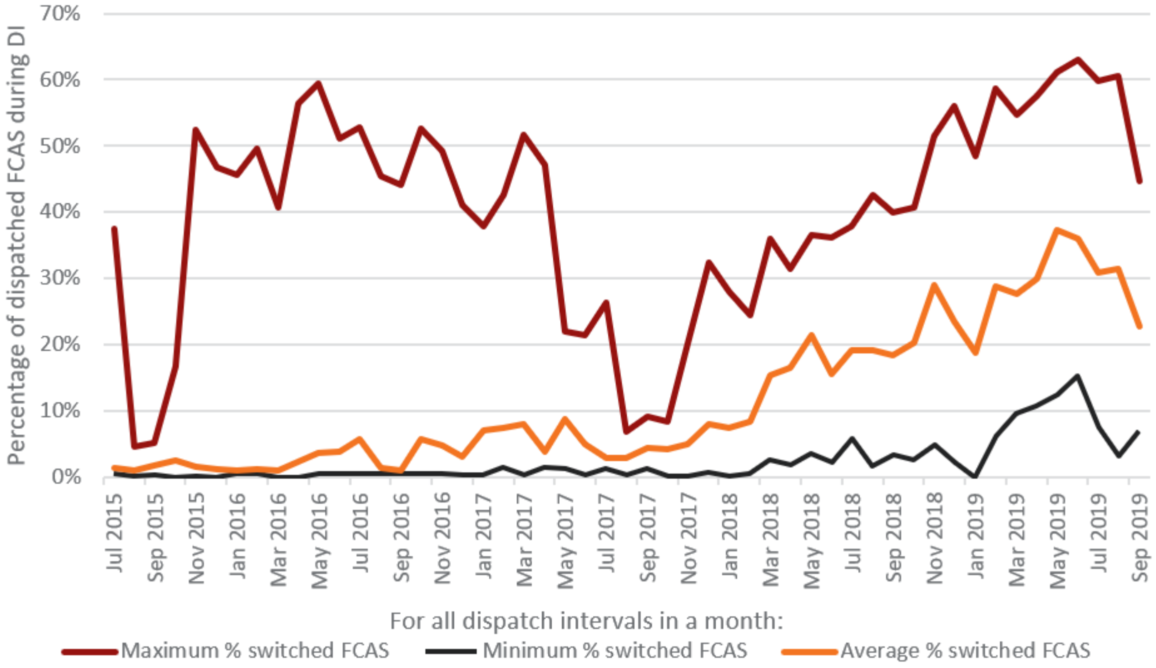
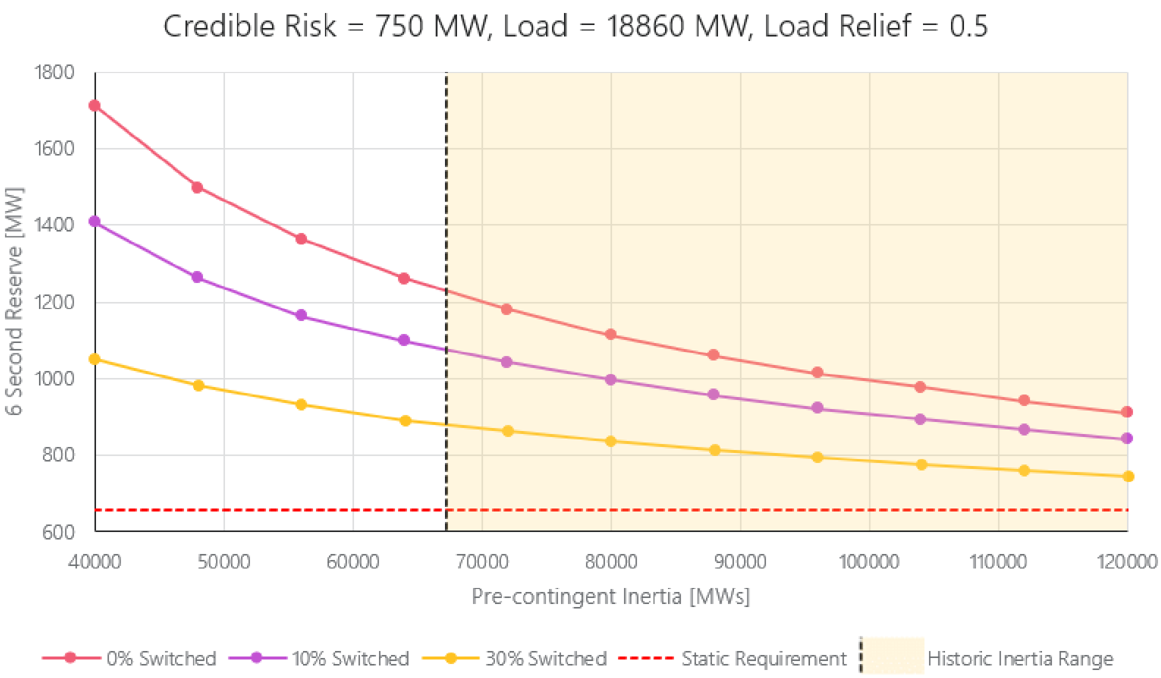


Figure 17 Reserve requirement for loss of Kogan with increasing proportions of switched reserve



B4.8.5 Limitations of switched FCAS

Continuous control

Switched FCAS is not continuously sensitive to frequency and so does not act to control it; rather, it gives it a discrete sized offset in one direction. While not explicitly valued by the MASS, the continuous control provided by frequency sensitive PFR, or governor-like control, is crucial to the operation of the power system.

Some level of frequency-sensitive PFR is required for control of frequency during normal operation and in response to credible events. It is also required for UFLS and OFGS to operate effectively.

Repeatability

Switched FCAS is a one-shot response. After it is triggered, it takes some time for it to be restored and re-armed. For complex events this allows some reserve to be tripped off that is then not available if needed later. A recent complex trip of a large thermal power station had some portion of the switched FCAS trip off on an initial under-frequency dip before the main disturbance some minutes later.

Frequency-sensitive PFR will respond to the frequency as long are there is headroom and energy available for the response. If high penetrations of switched control were to replace frequency-sensitive PFR with headroom, it would reduce system resilience to complex events.

Over-provision

As switched FCAS is a discrete sized MW response, in circumstances where less than the full amount is selected under the market an over-provision may occur if the full amount is delivered. This issue could be addressed to some degree by placing additional requirements on providers to manage the size of their response.

Over-responding to smaller events

If a risk smaller than the LCR trips, then switched reserve may cause the frequency to move above 50 Hz. In the NEM this is managed by staggering the switched reserve across five different under-frequency settings. These settings are typically set at time of registration. The amount armed at each stage is dependent on which providers are selected under the market.

Limiting provision from switched providers

A constraint is currently in place to manage the portion of Fast FCAS in Tasmania that comes from switched reserve.

EirGrid (Ireland) and SONI (Northern Ireland) both require a minimum amount of primary reserve to be dynamic, as opposed to switched or static reserve, because without dynamic reserve, system frequency cannot be controlled[42]. National Grid (Great Britain) also has a minimum dynamic requirement as part of its Firm Frequency Response Market[43]. National Grid periodically reviews the minimum dynamic requirement, with changes made recently to increase the proportion of frequency responsive reserve[44].

ERCOT (Texas) initially limited static reserve to 25% of the Responsive Reserve Service, increasing this to 50% by 2006[45]. As of November 2018, 60% of the Responsive Reserve Service could be provided by loads armed with under-frequency relays[46]. As with the modelling presented above, ERCOT found that some amount of switched load reduces the overall reserve requirement at lower inertia. These percentages serve as an example only, because the system conditions and requirements of the ERCOT system are different from those of the NEM.

Initially, a conservative limit within the range of those applied internationally is likely to be appropriate for the NEM. Addressing over-provision, along with dynamic modelling that allows the post-event frequency performance of the system to be predictively modelled for credible and non-credible events in the mainland, may allow for further refinement of the maximum switched quantity. Modelling would need to be supported by operational experience and monitoring.

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[42] See https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Annexes/ENTSO-E%E2%80%99s%20supporting%20document%20to%20the%20submitted%20Network%20Code%20on%20Load-Frequency%20Control%20and%20Reserves.pdf.

[43] See https://www.nationalgrideso.com/document/2501/download.

[44] See https://www.nationalgrideso.com/document/157216/download.

[45] See https://www.aemc.gov.au/sites/default/files/content/9207cd67-c244-46eb-9af4-9885822cefbe/Final-AEMC-DR-Report_International-Review-of-Demand-Response-Mechanisms.pdf.

[46] See https://www.dena.de/fileadmin/dena/Dokumente/Veranstaltungen/A_Global_Perspective_on__Electricity_Ancillary_Services/4_Julia_Matevosyan.pdf.

B4.8.6 MASS valuation of faster FCAS

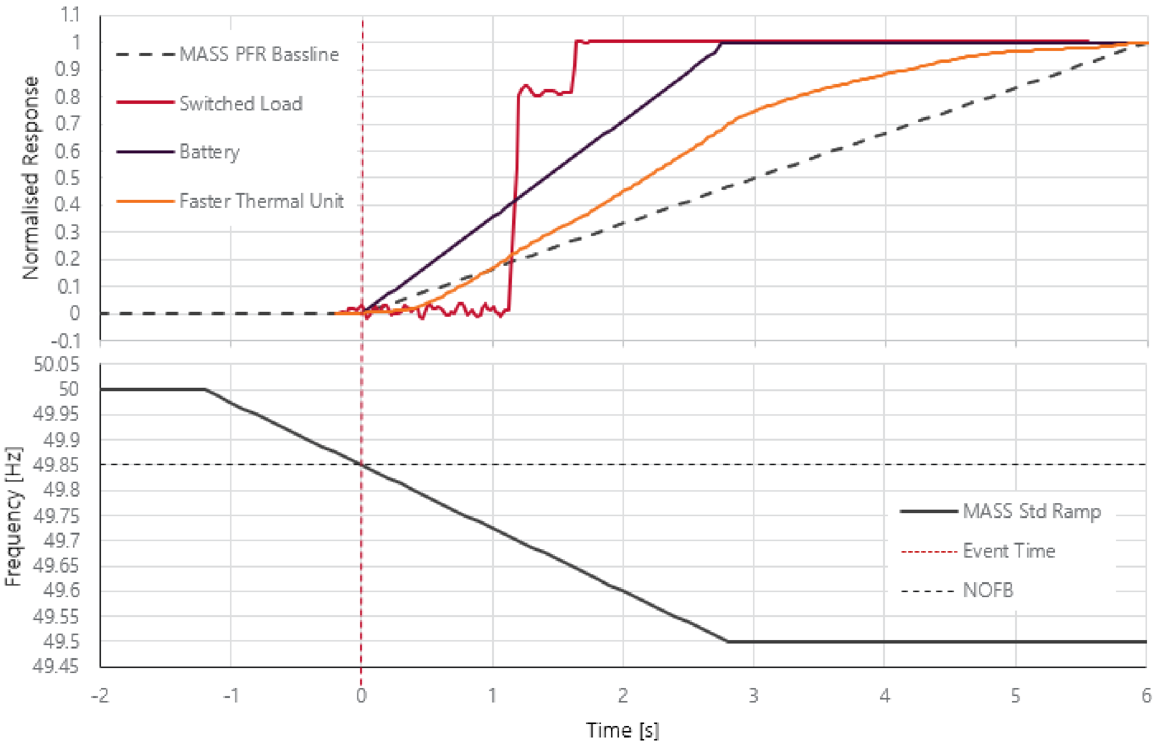
As discussed in Section B4.7, fast FCAS is measured at six seconds. In valuing PFR, the MASS uses a standard frequency ramp. In response to this ramp, the MASS sets a baseline PFR response that is a straight line increasing in active power from the time the frequency crosses the NOFB up to the maximum response six seconds after the NOFB crossing time. The extent to which the provider's average response is above or below this baseline sets how much their registered FCAS value is above or below their instantaneous 6-second output.

The result of this design is that faster providers may be registered for FCAS MW values significantly above their actual instantaneous MW provision. They may limit their response to an instantaneous value lower than their registered FCAS amount or only maintain headroom to ensure delivery of this lesser amount.

When conventional generators provided the bulk of FCAS, this would not have had as much of an effect. Some generators would have been marginally above the baseline, and some marginally below. With batteries contributing greater proportions of FCAS, the effect is potentially higher. This is also a potential consideration for switched FCAS providers, when they are selected for their full delivery.

Figure 18 illustrates the potential variation of these responses depending on the technology employed by FCAS providers. The responses have been normalised to reach the same amount of energy provided at six seconds.

Figure 18 Unit responses to standard frequency ramp used for demonstration of FCAS capability



It is appropriate to reward faster provision, however, increasing the speed of response will not reduce the reserve needed below the static requirement. The active power required to arrest frequency is always the same value, that is, the replacement of active power lost. By allowing the aggregate FCAS MW response to be less than the active power required to replace what was tripped, factoring in load relief, FCAS procurement alone will not ensure the frequency is arrested.

Table 5 shows the potential shortfalls in the required active power at six seconds for the example responses.

Table 5 Potential instantaneous MW shortfalls

Provider example	Potential shortfall in instantaneous MW at 6s
Faster thermal	10%
Battery	36%
Switched Load	32%

Currently, over-provision from switched FCAS providers will limit or cancel this shortfall when their full capacity is not selected. Batteries without a capped response, and with available headroom, will continue to support frequency below 49.5 Hz. This will assist in supporting frequency for non-credible events, but will not necessarily ensure the FOS containment requirement is met for loss of the LCR.

B4.9 Secondary risks

The FOS sets the frequency containment requirements for different categories of events. The event that is most often responsible for setting the raise reserve requirement is a generation event. For this class of event the frequency must be contained within 49.5 Hz to 50.5 Hz.

A generation event is defined in the FOS (A.3 Part D – Definitions) as:

1. *a* synchronisation *of a* generating unit *of more than 50 MW, or*
2. *an event that results in the sudden, unexpected and significant increase or decrease in the* generation *of one or more* generating systems, *totalling more than 50 MW in aggregate, within a period of 30 seconds or less, or*
3. *a* credible contingency event, *not arising from a load event, a* network event, *a* separation event *or a part of a* multiple contingency event.

Secondary risk is not a term defined in the NER or the FOS; however, here the term is used to refer to a potential for active power reduction that may occur concurrently with the trip of the LCR, through some causal connection. This does not mean that the secondary risk will eventuate for every trip of generation, but there is some potential for additional power imbalance.

The two secondary risks considered are:

- The potential for DPV to trip.
- The potential for utility-scale IBR to momentarily reduce output in response to a network fault, taking some time to recover.

The effect of these secondary risks has been added to the primary risk, or LCR, and the reserve requirement simulated. While the resulting event is a more onerous consideration than a single unit trip, it is arguably more likely than a multiple contingency event. For comparison with other sensitivity curves, the generation event containment criterion of 49.5 Hz has been applied in plotting the reserve requirement curves.

While these secondary risks have been looked at individually, both may eventuate at the same time because they are both related to network faults, and as such could have an additive effect.

This report focuses on the system intact condition, rather than the operation of islanded regions following a separation event. Secondary risks affect the operation of islanded regions, as they do the intact system, and would be expected have greater impact under these conditions due to the reduced inertia and availability of PFR in islanded regions. AEMO takes secondary risks into consideration in specifying minimum inertia requirements for islanded regions as part of Minimum Inertia Requirements[47].

[47] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

B4.9.1 DPV trip in conjunction with primary risk

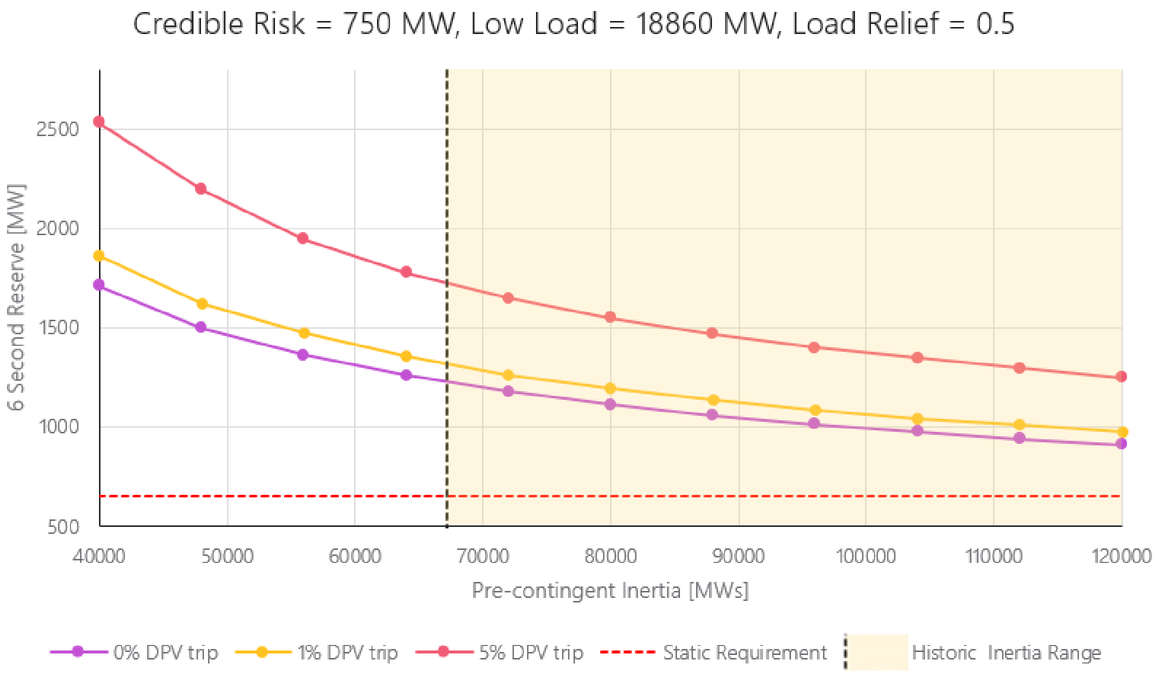
AEMO's recent *Technical Integration of DER* report[48] has identified a number of past events where DPV has responded by curtailing or tripping offline following a voltage disturbance.

A complex event involving three consecutive faults on 3 March 2017 in South Australia resulted in the estimated loss of 150 MW of output from small-scale PV systems across the region, with 40% of monitored systems reducing to zero output. Another event, a fault on the 500 kV network in Victoria on 18 January 2018, resulted in a 28% reduction in monitored output of small-scale PV systems. These events were coupled with loss or reduction in load that counteracted the effect of the PV loss, although the same level of load reduction is not certain for all events.

The net effect of an individual event will depend on the amount of PV online and its electrical proximity to the fault, the severity of the fault, and the load response. As the small-scale PV capacity online grows, it can be expected that the effect of PV loss will grow and become more significant relative to the loss of load. More information on DPV performance during events is in *Renewable Integration Study Stage 1 Appendix A: High Penetrations of Distributed Solar PV*.

As an indication of the potential impact of this on frequency control, an amount of DPV equivalent to between 1% and 5% of the maximum forecast of rooftop solar PV generation in Queensland in 2025 was tripped in conjunction with Kogan Creek in the simulation model. This corresponds to approximately 30 MW and 150 MW of extra risk. Figure 19 shows the resulting reserve requirement curve for the credible frequency containment criteria.

Figure 19 Indicative impact of DPV loss in conjunction with LCR trip



The loss or reduction of load in response to a voltage dip was not included in the model, so the amount of DPV tripped represents the net effect. These values have been chosen to give some illustration of the relative impact, but have not been empirically derived from past events in Queensland or power system studies. AEMO is undertaking work to better quantify the expected impact of the loss of DPV due to voltage disturbances[49].

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48 At https://aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

49 See https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations.

B4.9.2 Voltage Dip-Induced Frequency Deviation

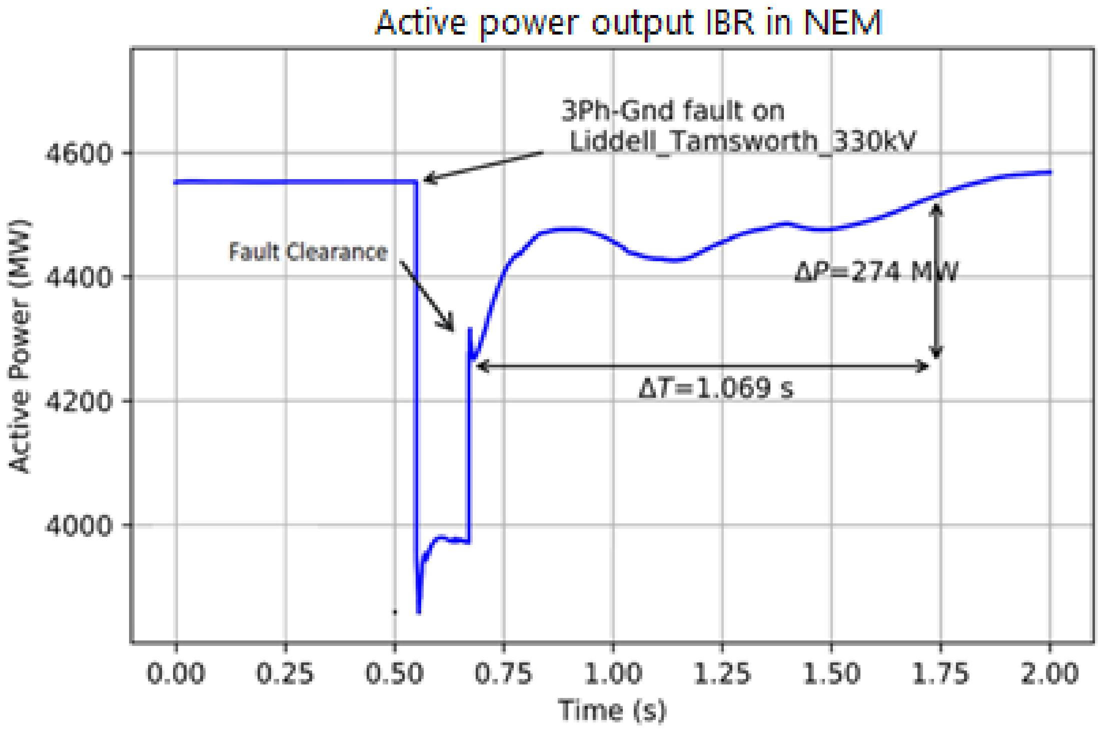
VDIFD is associated with the recovery phase of active power of inverters after a voltage disturbance.

The active power recovery of synchronous generators follows the recovering voltage and is therefore very fast. The active power recovery of wind turbine generators may be slower, to keep mechanical stress on the structure at acceptable levels. The impact of this issue is dependent on the type of wind turbine, and is aggravated by decreasing system strength and a broader propagation of voltage dips[50,51]. IBR without a mechanical prime mover, such as PV plant, can be controlled in such a way that recovery time is reduced.

To estimate the potential impact of VDIFD, selected faults were applied to a recent historical snapshot in PSSE and the post fault recovery time and active power dips measured from the aggregate response of all IBR. The snapshot was chosen to have reasonable amount of wind online at a lower load.

An example of an active power recovery profile is shown in Figure 20.

Figure 20 Example active power recovery in response to a 3ph fault



The most significant faults are shown in Table 6. The case chosen is not necessarily the most onerous possible, but is indicative of the VDIFD that could reasonably associate with large generators due to their electrical proximity. Queensland active power recovery was dominated by solar plant and so was much faster, having less impact on the frequency nadir.

[50] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

[51] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf.

Table 6 Active power recovery for select 3ph network faults

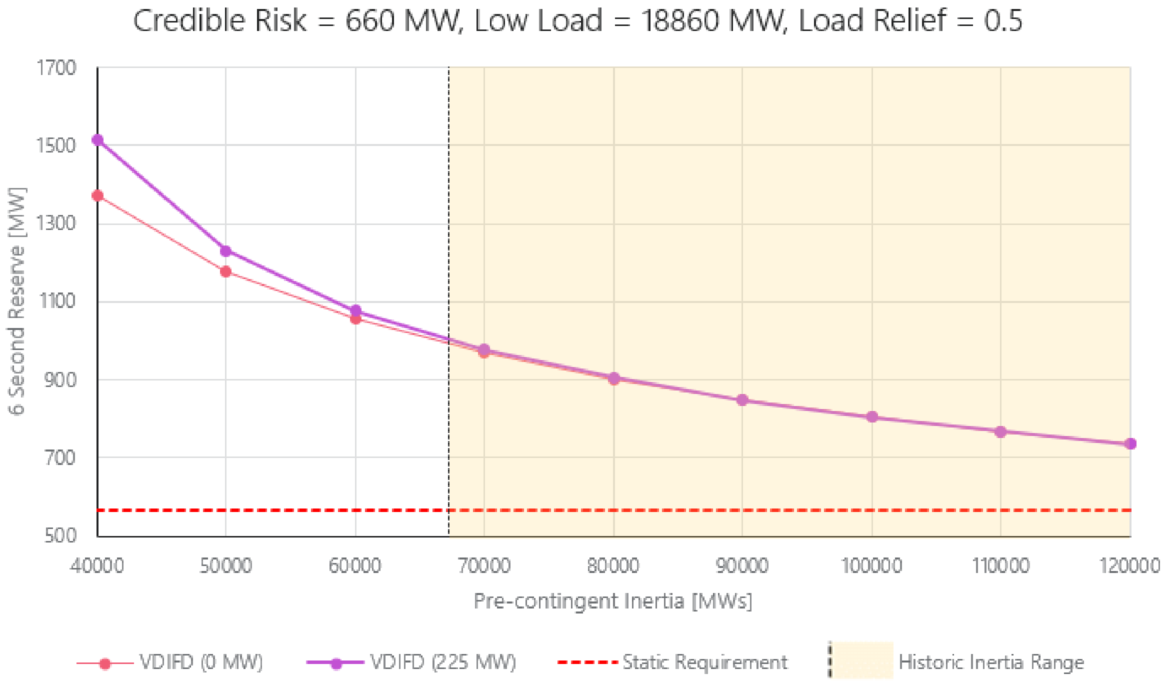
Region	Power plants in electrical proximity	Fault	Post fault recovery	
			$\Delta T\ (s)$	$\Delta P\ (MW)$
NSW	Eraring (720 MW)	Eraring_KempCreek_500kV	1.027	117
	Mt Piper (700 MW)	Wellington_MtPiper_330kV	1.306	218
	Liddell (500 MW)	Liddell_Tamsworth_330kV	1.122	274
	Bayswater (660 MW)	Bayswater_Regntvle_330kV	1.123	225
	Vales Point (660 MW)	Valespnt_NwCstle_330kV	1.053	133
VIC	Loy Yang (560 MW)	Loyyang_Basslink_500kV	1.018	294
	Laverton (156 MW)	Brooklyn_Altona_220kV	1.286	169
	Newport (500 MW)	Thomas.T_S. Morang_220Kv	1.285	230
SA	Snowtown WF (99 MW)	Snowtown_Blythe_275kv	1.05	190
	Pelican Point (160 MW)	Pelican_Parafield_275kV	1.0	238
QLD	Townsville (160 MW)	Ross_Townsville_275kV	0.07	375
	SF concentration	Strathmore_Nebo_275kV	0.09	476
	Stanwell (365 MW)	Stanwell_Bldercoumbe_275kV	0.082	331
	Kogan Creek (750 MW)	Kogan_WesternDowns_275kV	0.01	11

The trip of a unit is not necessarily coupled with a voltage dip, however, a network fault occurring with a unit trip is plausible.

A modelled active power recovery profile, with a recovery time of 1.2 seconds, has been used to simulate the VIFD impact coupled with the loss of a 660 MW NSW unit. This case was chosen because the unit size and associated size and recovery time of the active power reduction had the largest impact on the reserve requirement.

As shown in Figure 21, the VDIFD has little impact under high inertia conditions, becoming measurable as inertia decreases.

Figure 21 Sensitivity to VDIFD at low load, loss of New South Wales 660 MW unit



VDIFD is locational, and the growth in its potential to influence frequency will depend on the characteristics of new wind capacity and its connection location. In the NEM, technical requirements assist in managing this issue, including the system response to voltage disturbances requirements (S5.2.5.4) and the active power recovery requirements (S5.2.5.5) in the NER.

While the impact on the reserve requirement for this individual mainland case is minimal, the VDIFD impact on RoCoF can be significant. In Tasmania, the response of Basslink and wind farms to a fault can result in significant active power reduction during the fault clearing period, causing high RoCoF. To reduce this, constraint equations in the dispatch engine (NEMDE) limit the import on Basslink and the output of semi-scheduled wind generation. This is also a consideration in South Australia, due to the high locational concentration of wind generation.

VDIFD should be monitored as the generation mix changes.

B4.9.3 Coincidental ramp of variable renewable energy

Coincidental ramping of VRE such as wind and solar generation can create a mismatch in the power balance. Unlike the secondary risks described above, these disturbances are not causally linked to the trip of the LCR. As part of the RIS program, AEMO is progressing work to better understand the impact of the variable nature of wind and solar generation on maintaining frequency.

Additional information on coincidental ramping VRE is in *Renewable Integration Study Stage 1 Appendix C: Managing variability and uncertainty*.

B5. Non-credible events

This section provides qualitative information on the changing nature of non-credible events, discussing the impact of increasing system complexity and DPV with relation to post-non-contingent outcomes, and outlining the uncertainty that exists around the maximum permissible RoCoF for the NEM.

Key insights

- DPV behaviour, IBR behaviour, and run-back and intertrip schemes are making the system more complex. Coupled with reduced inertia and load relief, post-contingent outcomes are potentially worse than those seen historically.
- The **maximum permissible RoCoF** for the NEM is not well understood. The outcomes of non-credible events may be exacerbated by DPV trips on RoCoF protection, however, the level at which this becomes material has not been quantified. High RoCoF may also affect relays used for various network functions.
- Access to continuously frequency-sensitive PFR is required within a region for it to successfully island. AEMO is examining **regional contingency FCAS requirements** to ensure areas at risk have access to adequate PFR and associated MW reserves at all times.

Non-credible events are more onerous than credible events, and include the trip of multiple generating units or double circuit transmission lines.

Under the FOS, a different set of criteria applies to non-credible events. For multiple contingency events, reasonable endeavours must be made to contain system frequency between 47 Hz and 52 Hz. For under-frequency events, UFLS can be used to assist in meeting the frequency criteria. There are also reasonable endeavours criteria for frequency stabilisation and recovery after a multiple contingency event.

B5.1 Changing nature of risk

For the same non-credible events that have been considered in system planning historically, there is a widening range of potential consequences.

Inertia and load relief, two key parameters that underpin the system's frequency performance, are declining. These changes are taking the power system into new regions of operation. At the same time, there is an increasing proportion of generation that has been built relatively recently, so less operating experience with the current generation mix has been accumulated.

RoCoF levels, even excluding additional contributions from secondary risks, are projected to increase. The system limits for RoCoF in relation to DPV, some utility-scale generation, and protection relays used in switched reserve and distribution networks have not been fully quantified in the NEM.

High RoCoF could worsen the outcomes of non-credible events through DPV being disconnected. While there are technical requirements for RoCoF for utility-scale generation, the actual withstand capability of all generating units is not presently known[52], adding additional uncertainty to the range of potential outcomes to high RoCoF events.

Historically, network limits have been managed though pre-contingent curtailment of generation through security constraints. For some wind and solar projects, run-back or intertrip schemes have been introduced to manage specific issues. These schemes bring added complexity to the system. By linking otherwise independent events (for example, the loss of one transmission line with the trip of multiple generators), these schemes can complicate the outcomes of non-credible events.

VDIFD and DPV sensitivity to voltage disturbances

As described in Section B4.9, VDIFD and DPV trips due to voltage disturbances have the potential to influence non-credible events. As the initial RoCoF following an event is related to the size of the power lost, post-event RoCoF for non-credible events will be larger. These secondary risks have the potential to increase post-event RoCoF further. If not managed, this has the potential to lead to cascading outages as equipment that is not designed to withstand these RoCoF levels disconnects.

Under-/over-frequency trip of DPV

In addition to trips or output reduction in response to voltage disturbances, DPV may trip in response to an over- or under-frequency. DPV is tripped according to its under-frequency or over-frequency trip setting.

AEMO conducted a survey of small-scale PV frequency trip settings in 2016[53]. The trip settings applied depend on the version of *AS/NZS 4777 Grid Connection of Energy Systems via Inverters* that was applicable at the time of installation. This standard was revised in October 2015 (AS/NZS 4777.2–2015), with the revision including a requirement that inverters will not disconnect between 47 Hz and 52 Hz. The previous revision of this standard did not include this requirement.

DPV that trips between 47 Hz and 52 Hz will affect the power balance within the range that frequency is allowed to deviate for non-credible events. In the under-frequency portion of this range, DPV that trips counteract UFLS to some degree. The survey found that 46% of inverters within the NEM would trip within the range.

DPV can also make a positive contribution to frequency control during an over-frequency event by reducing output through an over-frequency droop response. This response was introduced into the AS/NZS 4777.2:2015 specification.

Under-frequency tripping of DPV has been witnessed for actual events on the NEM. A separation event on 25 August 2018[54] resulted in an over-frequency event in Queensland and South Australia, while there was an under-frequency event in Victoria and New South Wales. The over-frequency droop response as well as over-frequency inverter trips proved beneficial in Queensland and South Australia. In Victoria and New South Wales, an estimated 190 MW of small-scale PV (19% of New South Wales' and 11% of Victoria's small-scale PV generation at the time of the event) was tripped on under-frequency, exacerbating the under-frequency.

RoCoF effect on DPV and protection relays

DPV may deliberately trip for RoCoF that exceeds a RoCoF protection setting. Sometimes this protection element is used as a form of anti-islanding protection. There is no current standard for RoCoF withstand for DPV, however, this is being considered as part of a review of AS/NZS 4777[54]. The RoCoF settings in place for existing DPV installations are not well understood.

RoCoF may also affect the way protection relays operate, including those used to trigger switched reserve and EFCS. As switched reserve fills a greater proportion of the FCAS procured, it will be relied on more in the

[52] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/PSFRR/2018_Power_System_Frequency_Risk_Review.pdf.

[53] See https://aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf.

[54] See https://aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

case of extreme events. More information on the relays employed is needed to assess if higher RoCoF has the potential to delay or prevent provision of switch FCAS.

DPV penetration into UFLS blocks

As increasing DPV reduces customer load, it also has the potential to reduce the size of the load blocks for UFLS. This issue is addressed in detail in *Renewable Integration Study Stage 1 Appendix A: High Penetrations of Distributed Solar PV*.

B5.2 Non-credible separation events

Non-credible separations, or islanding of a part of the NEM, are events that deserve specific attention. Historically there have been instances of islanding of South Australia and Queensland through trips of the double circuit interconnectors that connect these states with the rest of the NEM.

Queensland has separated from the rest of the NEM twice in the last 10 years, on 13 November 2011 and 25 August 2018, both due to lightning strikes. South Australia has separated from the rest of the NEM nine times in the past 10 years, including non-credible separations in 2018, 2019, and 2020. Recently New South Wales and Victoria separated due to bushfires[55].

The Power System Frequency Risk Review (PSFRR)[56] is tasked with reviewing non-credible contingent events, including South Australia and Queensland separations, and can also request the declaration of protected events under the NER. Protected events are non-credible events that have firmer frequency containment criteria. South Australian separation has been declared a protected event under destructive wind conditions.

Trip of a double circuit interconnector may be re-classified as credible under abnormal conditions or when one of the two circuits is on planned outage. The *Inertia Requirements Methodology and Inertia Requirements and Shortfalls*[57] specifies minimum amounts of regional inertia when there is a credible risk of islanding.

In the case of a non-credible separation of a region, some level of continuously frequency-sensitive PFR will be required in that region for it to successfully island. If no PFR is available, the power imbalance following separation will cause the frequency to rise or decline to the point where UFLS or over-frequency generator tripping is initiated. As the load or generation tripped is in discrete sized blocks, assuming the power balance is over-corrected, the frequency will swing in the other direction and cause tripping when it reaches the opposite extremity. This pattern could continue in an uncontrolled way until widespread loss of generation on over-frequency or under-frequency protection results in a black system event.

Separation can occur at multiple locations, so distribution of PFR across the NEM will make the system more resilient to separation events. The introduction of the Mandatory Primary Frequency Response Rule will assist in maintaining and extending PFR distribution.

In the NEM, contingency FCAS is procured for the NEM as a whole, and under normal circumstances there are no regional frequency sensitive reserve requirements in place. Following the 25 August 2018 event[58], several recommendations were made relating to frequency control. One of these recommendations was to consider regional requirements for contingency FCAS[59]. AEMO is investigating regional FCAS requirements for South Australia and Queensland. The risk of non-credible separation of South Australia will be greatly reduced by the construction of the second interconnector due for completion in 2023-25.

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[55] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en.

[56] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/PSFRR/2018_Power_System_Frequency_Risk_Review-Final_Report.pdf.

[57] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[58] See https://aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

[59] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf.

B6. Managing transition to lower inertia

This section outlines how a staged transition to lower levels of inertia would allow the required reserve qualities and capacity to be built in advance of the system needs, and uncertainties in system performance managed.

Key insights

- Faster frequency response allows the power system to operate at lower levels of synchronous inertia, however no large power system operates without synchronous inertia. Some level of **synchronous inertia** will be needed for the foreseeable future.
- To manage the expansion of the envelope of system operation progressively, a **staged approach to operating at lower inertia** should be considered. This would allow the system frequency control design to be adapted to the changing system, with capacity built in advance of the requirement becoming evident on the system.
- Progressing towards low inertia will necessitate the **revision of ancillary service arrangements**, understanding **system RoCoF limits**, and the adoption of **near-universal PFR**.
- Development of a **system frequency model** able to predict post-contingent frequency outcomes is needed to enable lower inertia conditions to be studied for credible and non-credible events, and for the design of effective EFCS.

With inertia and load relief declining, the power system will be entering new regions of operation. Under these conditions, the requirements for reserve are changing. The way reserve has been historically allocated will not be sufficient, by itself, to ensure the FOS is met for credible events.

Tasmania and South Australia have inertia-sensitive reserve requirements[60]. Tasmanian FCAS constraints managing the trip of Basslink include an inertia term, and South Australia has inertia-sensitive FCAS constraints when islanded.

Under the current market framework, the amount of mainland reserve is not increased at lower inertia values or managed through reducing the size of the LCR. Changes are needed in the way reserve is managed to ensure the FOS requirements will be met at lower inertia. These changes could include a combination of:

- Scheduling more reserve.
- Ensuring a proportion of faster reserve.
- Reducing the size of the LCR.

[60] See https://www.aemo.com.au/-/media/Files/PDF/Transfer_Limit_Advice_Tasmania_and_SA_FCAS_2_July_14.pdf.

B6.1 PFR Rule change

The implementation of the Mandatory PFR Rule change will improve the resilience of the system for credible and non-credible events[61], which will be increasingly important under lower inertia conditions. It is also needed to improve the control of frequency under normal conditions and to allow AEMO to model and analyse the performance of the power system (especially for complex dynamic behaviour), which is essential for AEMO's ongoing management of power system security.

However, the PFR Rule change does not ensure an adequate level of reserve, and the requirements around its provision are not as prescriptive as FCAS requirements.

Currently the FCAS markets are responsible ensuring a base level of frequency sensitive reserve. The Mandatory PFR Rule change will not alter this approach.

B6.2 Faster frequency response

Faster frequency response allows the power system to operate at lower levels of synchronous inertia, however, no large power system operates without synchronous inertia. Replacing synchronous inertia with fast acting control action may result in a system with different system dynamics from those of today. This requires verification that the measures put in place to allow operation at lower inertia are working as expected, with operational experience being built progressively. Some level of synchronous inertia will be needed for the foreseeable future.

As the share of faster reserve grows, consideration needs to be given to how it is valued, to ensure the quantity requirements are not eroded due to faster provision, as discussed in Section B4.8.6. Consideration of the locational-based impacts of FFR is also needed. Switched reserve has specific qualities that require that its overall share of reserve provision be managed.

B6.3 Frequency containment requirements

The 0.5 Hz FOS containment requirement is relatively tight, compared to some used internationally. While relaxing this requirement would reduce reserve requirements, this is not recommended as an initial option.

Relaxing this requirement would reduce the margin between the expected frequency nadir and the triggering of the first UFLS block. This would need to be coupled with the ability to predict frequency nadirs for credible risk with a higher degree of confidence. The impact of secondary risks along with operating with lower load relief and inertia are still not fully quantified. Under normal conditions, reserve is only scheduled for loss of the LCR. The FOS does not maintain as firm requirements for non-credible events. Reducing the containment requirement would affect the system's resilience to non-credible events as well as for the loss of the LCR.

B6.4 Staged transition to lower inertia for system intact

The adaption of the MASS, or ancillary service arrangements more generally, to the changing system requires a design range for inertia, with the speed and amount of the required PFR set to ensure the FOS requirements are met. Expanding the inertia operating range in a staged manner would allow the system frequency control design to be adapted to the changing system, with capacity built in advance of the requirement becoming evident on the system.

The extent to which higher RoCoF will impact the system, particularly for non-credible events, has not been fully quantified for the NEM. RoCoF limits are currently not specified for the NEM as a whole. The impact of RoCoF on DPV and protection relays used in various network functions should be investigated, with a view to understanding the technical operating envelope for RoCoF. Managing the level of minimum inertia would

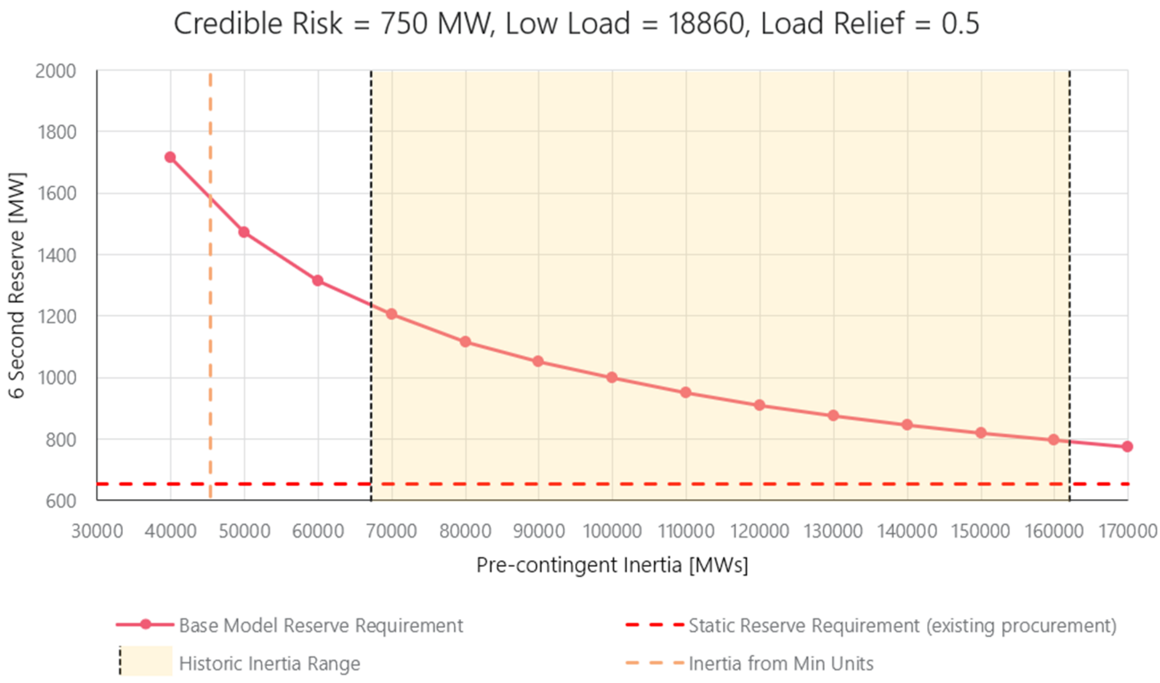
[61] See https://www.aemc.gov.au/sites/default/files/2019-08/Rule%20Change%20Proposal%20-%20Mandatory%20Frequency%20Response.pdf.

allow the impact of RoCoF to be understood through additional studies and hardware testing, system monitoring, and operational experience. Progressive assessment of RoCoF and inertia limits has been employed by system operators internationally.

To manage the expansion of the envelope of system operation progressively outside of existing operational experience, a staged approach to operating at lower inertia should be considered.

Figure 22 shows the modelled reserve requirement at low load across the historic inertia range. The expected inertia available from system strength requirements is shown for comparison.

Figure 22 Reserve requirement



A system inertia safety net in range of 55,000 MWs to 65,000 MWs is likely to be appropriate as an initial minimum safety net value for system intact. This range is suggested because:

- The minimum inertia should be set to allow the envelope of operating experience to be progressively expanded, and so should be within range of the historical minimum.
- As the inertia is decreased to this range, the required reserve when set according to the existing MASS requirements is relatively linear. Above this range, the reserve requirement increases more rapidly. The reserve requirement increases 400 MW across the 94,800 MWs historic inertia range. Across the 21,800 MWs range between the historic minimum and the expected inertia through system strength[62], the reserve requirement increases another 400 MW.
- At this level of inertia, instantaneous RoCoF for a 750 MW risk would be ~0.3 Hz/s. This level of RoCoF is within the range of international experience[63]. Events involving secondary risks or non-credible events will result in higher RoCoF. RoCoF should be maintained within conservative limits until system RoCoF limits are better quantified.
- Beyond this level, secondary risks carry a greater impact.

[62] System strength requirements require synchronous generation to be online, and so make inertia available. See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

[63] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

B6.5 Further progression towards low inertia

Any inertia safety net value should be reviewed periodically, with the aim of reducing it as the system's behaviour at lower inertia is better understood and mitigation measures are put in place. As a prerequisite for reducing inertia below the initial safety net value, towards the expected level available through system strength, a set of actions would need to be taken.

As a minimum, these actions would include:

- Ensuring the ancillary service arrangements are in place to operate over the extended inertia range. This includes ensuring the required speed and volume of PFR match the size of the LCR and the FOS containment requirements. Some level of revision of the existing ancillary service arrangements will be required irrespective of the introduction and level of an inertia safety net, and may need to be in place before transitioning past the initial safety net value.
- Investigating the effect of higher RoCoF on DPV, utility-scale generation, switched reserve providers, and protection relays used in various network functions.
- Developing a system frequency model able to predict post-contingent frequency outcomes based on generating unit dispatch. This would enable lower inertia systems to be studied for credible and non-credible events.
- Continued assessment of the adequacy of EFCS, including UFLS, at lower inertia values.
- Adopting near-universal PFR enablement from the generation fleet.

The minimum set of synchronous units required to be online for system strength will provided an approximate level of 45,350 MWs[64] of inertia for the mainland after the four ElectraNet synchronous condensers are brought online. While the minimum synchronous unit requirements are not in place to manage frequency control or RoCoF, it will likely form a backstop inertia value, providing all of the above actions are worked through successfully. It is expected that the inertia safety net value could be progressively lowered to a comparable level.

B6.6 Regional inertia limits

The Minimum Inertia Requirements[65] set the required regional minimum inertia values to operate an island (Secure operating level of inertia), or when there is a credible risk of islanding (Minimum threshold level of inertia). These requirements do not ensure a non-credible loss of an interconnector will result in the formation of a viable island, as the Inertia Rule assumes that the interconnector flows can be constrained to zero when there is a credible risk of separation. The proposed system intact inertia safety net does not address this. In investigating regional contingency FCAS requirements, regional inertia availability should be considered.

In formulating the regional minimum inertia values, a number of assumptions are different to those applied in the system intact case. The applicable frequency containment band is 1 Hz for an islanded region or when there is a credible risk of islanding, rather than the 0.5 Hz requirements for system intact. It is also assumed that the largest generator within an islanded region will be dispatched down to its minimum output to reduce the size of the managed risk. The previously assumed load relief factor value of 1.5 was used in the assessment of the existing reginal minimum inertia requirements. These will be updated over time, as required. As summary of the existing inertia limits is given in Table 2.

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[64] Inertia levels available through system strength requirements, prior to synchronous condenser installation in South Australia, are given in *the Inertia Requirements and Shortfalls* document, available via the footnote below. Revision of the minimum sets of units needed to maintain system strength could change the inertia these requirements would make available.

[65] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

There are other locational considerations for inertia, such as transient and small signal stability, that are separate from the system intact inertia safety net.

B6.7 Tools and models

The existing tools AEMO uses to model frequency need to be updated so that they are able to predict system frequency performance for an event of interest, taking into account the capabilities of different units and a particular dispatch scenario.

The Mandatory PFR Rule change includes several provisions to make the PFR from generators modellable and predictable, including the use of consistent settings and a technical specification for the way PFR should be delivered.

These provisions need to be coupled with appropriate modelling of the response of individual generators to improve on the capability of existing tools. This would allow credible and non-credible events to be studied for planning a changing system.

System frequency models benefit from being progressively improved and adapted based on validation against real events. This requires a level of system monitoring, ideally including high-speed monitoring of individual generators.

It is common for power system operators to include frequency assessments as part of their dynamic security assessment tools, which run simulations to confirm power system security close to real time. With the changes affecting power systems globally, these tools are becoming increasingly important. These types of tools allow the adequacy of PFR, and frequency control arrangements more generally, to be monitored between events. This is important, because events do not necessarily occur at the worst-case alignment of risk size, inertia, PFR performance, headroom, and load response. Trending simulated contingency outcomes, coupled with progressively validating models based on real events, can be valuable in tracking changing system conditions.

Models that consistently and accurately simulate the frequency performance of generating units are a prerequisite to developing these tools.

B7. Single bus model

Lumped governor model

The single bus model has been implemented using the standard GGOV1 model to represent the aggregate reserve response. The GGOV1 model parameters have been chosen to be representative of the larger thermal units, so as to achieve a reactivity within the range of existing Fast FCAS providers. PFR of this quality represents a large proportion of contingency FCAS provision.

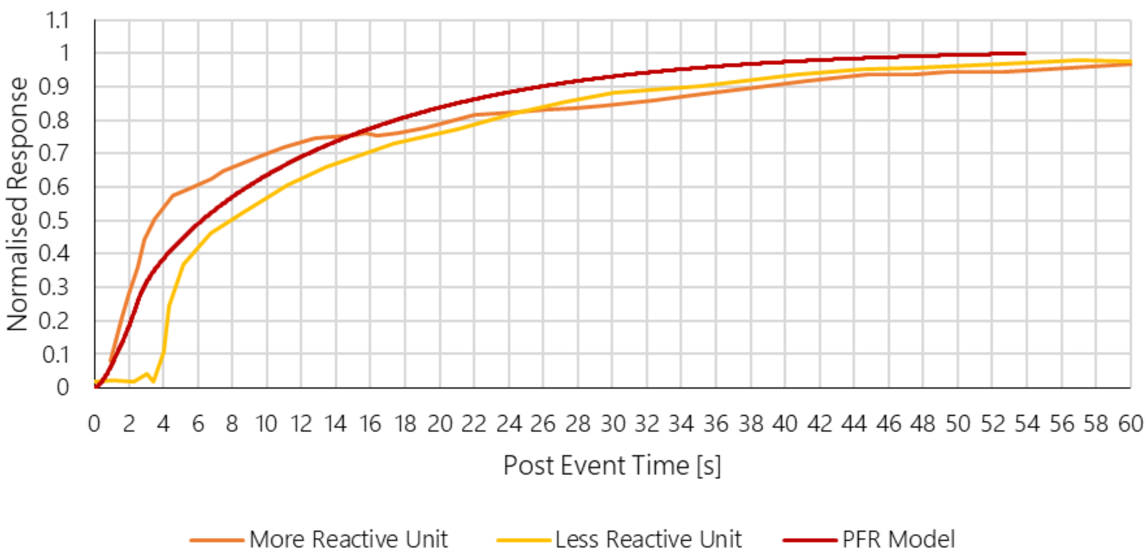
The key parameters for the GGOV1 model are provided in Table 7.

Table 7 GGOV1 key model parameters

Droop	Kpgov	Kigov	Tb	Tc	Ta	Deadband
0.05	10	2	3	1.5	0.1	0.03

Figure 23 shows two measured sub-critical steam generator responses to an injected MASS standard frequency ramp. One of the measured traces is representative of a more responsive unit, the other of a less responsive unit. The model's response to a MASS standard frequency ramp is provided for comparison. It is the response out to six seconds that is the most critical, given the way the reserve is scheduled in the modelling.

Figure 23 MASS standard ramp response comparison

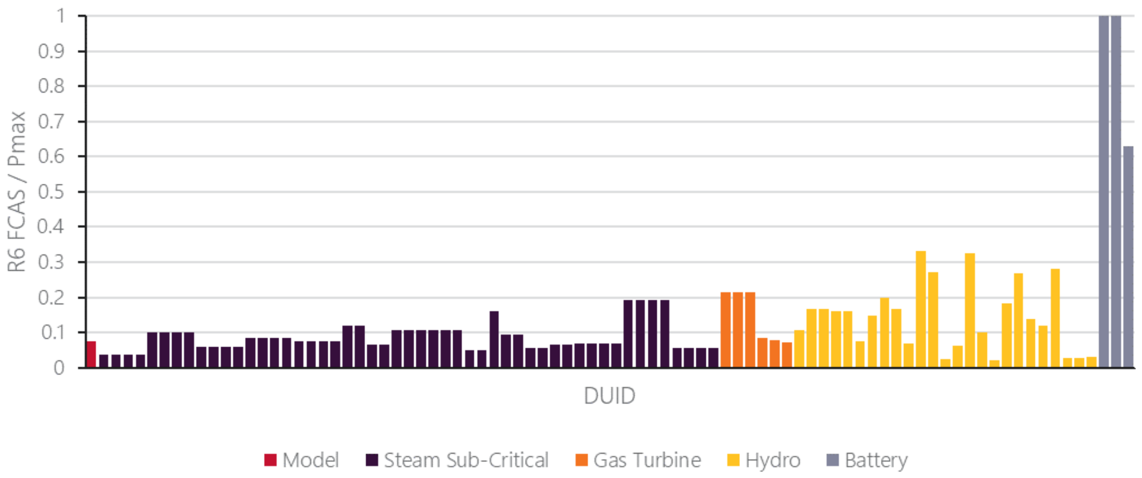


The PFR from this model is capped at the scheduled reserve value using the maximum valve position parameter. This prevents more reserve being delivered than that scheduled, which may introduce additional conservatism into the speed of the response when approaching the maximum valve position. This does not materially affect the result in most cases.

Comparison of the model to the 6-second FCAS providers

As a measure of reactivity, the ratio of the 6-second FCAS provision to the maximum active power of the unit has been plotted for the majority of registered FCAS participants in Figure 24. The same ratio for the model is also plotted for comparison. The reactivity of the model is in the lower-mid range of reactivity of the subcritical steam R6 FCAS providers.

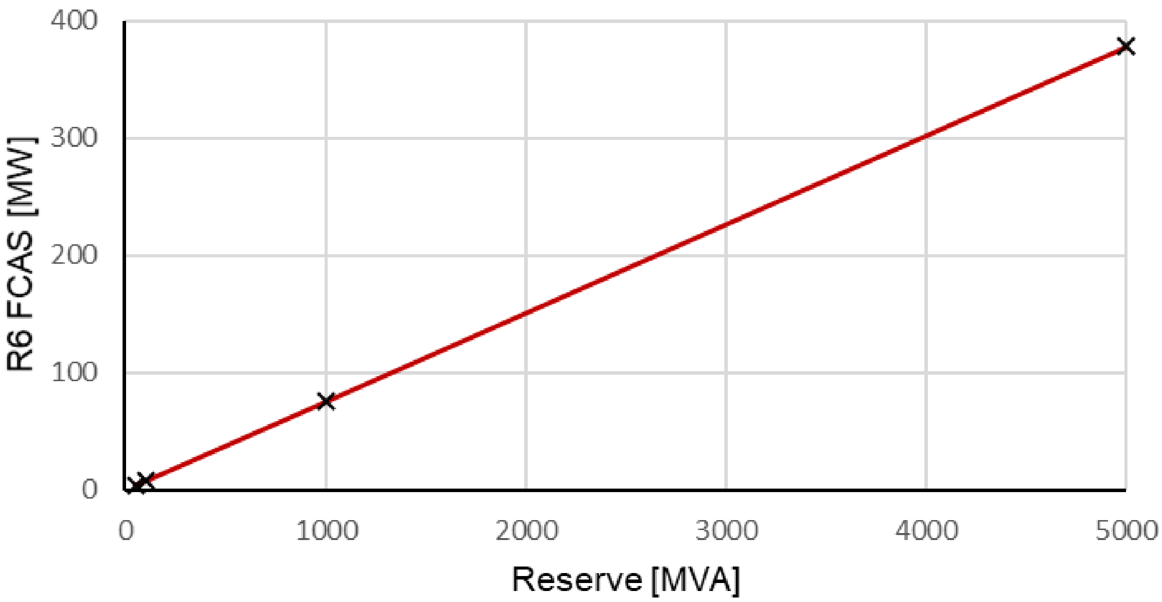
Figure 24 Reactivity of Fast Raise FCAS providers



Scheduling of reserve

The megavolt-amperes (MVA) base of the model is set according to the reserve scheduled, as calculated from the FCAS validation tool[66], used on the model's output. The relationship between the amount of reserve and the scheduled MVA is shown in Figure 25. The turbine rating has been set to match the MVA of the generator. In reality, for large thermal plant, the turbine rating could be set lower than the electrical machine MVA. This does not affect the modelling as the value of interest is the reserve capacity.

Figure 25 FCAS dispatch Logic based on MASS assessment of model output



[66] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/market-ancillary-services-specification-and-fcas-verification-tool.

Modelled governor dead band

As the model schedules reserve based on the MASS, the reserve requirement is largely insensitive to the modelled governor deadband for N-1 scenarios.

The deadband on the frequency responsive model has been set at +/-150 mHz. If the same level of FCAS providing plant (MVA and headroom) is kept and the deadband reduced to a narrow value (+/-15 mHz) then the frequency nadir will be improved significantly. This is because the governor will see a larger frequency error signal and so will be more responsive.

In contrast, if the reserve is scheduled according to the MASS measurement of the frequency responsive model with a narrow deadband, a lower MVA of plant will be scheduled. Under this scenario, the difference in the required reserve modelled between a narrow and wide deadband is marginal, but the plant MVA needed to achieve the response is much less.

From a system perspective, a narrower deadband is preferable as it will achieve a greater PFR from both units that are and are not selected for FCAS and have available headroom.

Comparison to past events

The model's response was compared against six historical frequency events, as listed in Table 8. These were selected because the experienced frequency changes were higher than average, providing a more extreme worst case for comparison.

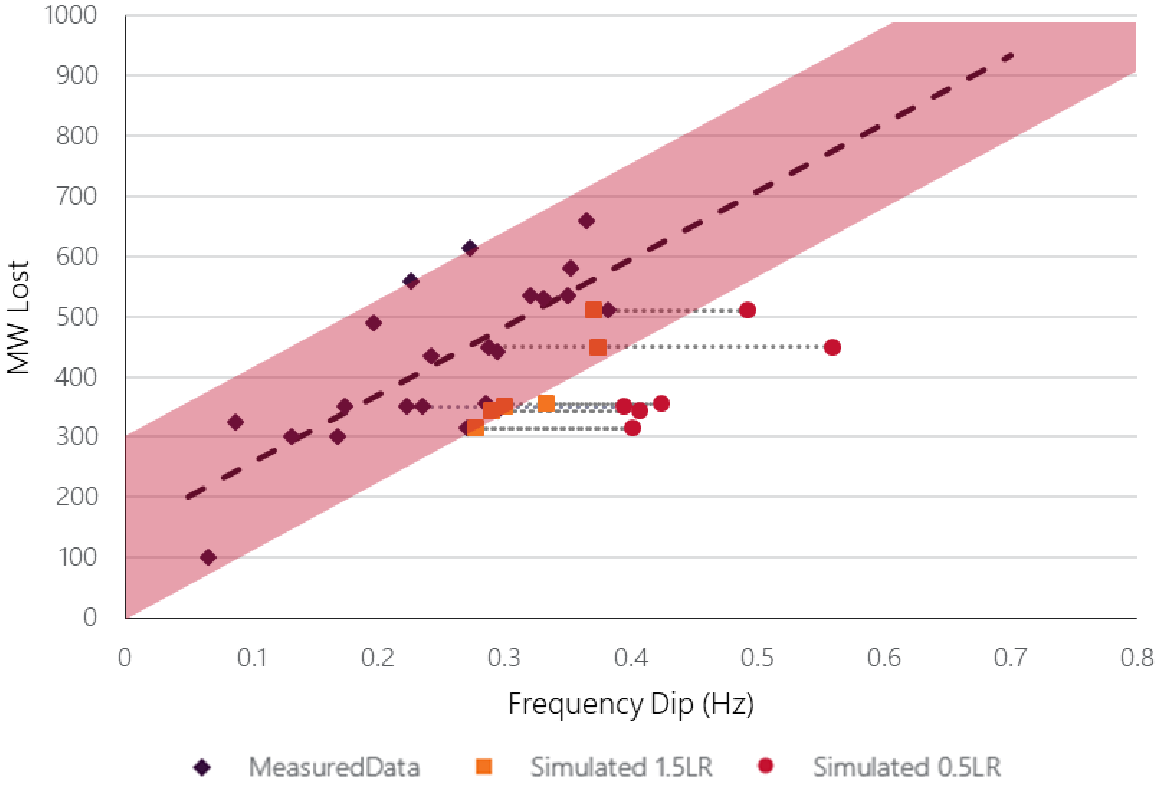
Table 8 Historical frequency events 2018-19 used for model comparison

ID	Event	Description	Mainland post-contingency inertia (MWs)	Mainland Operational Demand (MW)	Total Dispatched R6FCAS (MW)	Dispatched Switched FCAS (MW)
1	23/12/2018 09:17	Trip of Liddell Unit 1 (1,620 MWs) from 350 MW	79,294.6	15,686	452.88	66.52
2	27/01/2019 04:50	Trip of Bayswater Unit 1 (2,480 MWs) from 510 MW	96,909.3	16,699	556.37	262.14
3	25/02/2019 12:03	Trip of Newport Power Station (2,752 MWs) from 450 MW	95,633.7	20,753	372.17	95.73
4	19/02/2019 13:24	Trip of Callide B Unit 1 (1,048 MWs) from 315 MW	100,102.4	21,590	332.7	84.00
5	05/02/2019 22:36	Trip of Tallawarra (3,900 MWs) from 343 MW	95,933.2	21,465	382.25	86.00
6	28/12/2018 00:43	Trip of Bayswater Unit 1 (2,480 MWs) from 351 MW	86,157.5	19,117	469.95	74.35

Figure 26 provides a summary of frequency events recorded during the 2018-19 financial year for which 20 ms high-speed monitoring (HSM) data was available[67]. The modelled nadir for the six chosen events is shown for comparison. Both the modelled and measured frequency dips are the change in frequency from before the event to the lowest point. Variation in the starting frequency means the nadir may have been higher or lower in absolute terms. The linear trend in frequency depression in relation to the power imbalance, as well as the maximum deviation from the trend are also shown.

[67] Figure 26 shows the change in frequency, rather than the absolute nadir. The variability around the fitted linear relationship is shown by the shaded red area. Accounting for the ±0.15 Hz variability in the starting frequency would add additional uncertainty to the absolute nadir time.

Figure 26 **Measured and simulated frequency depression**

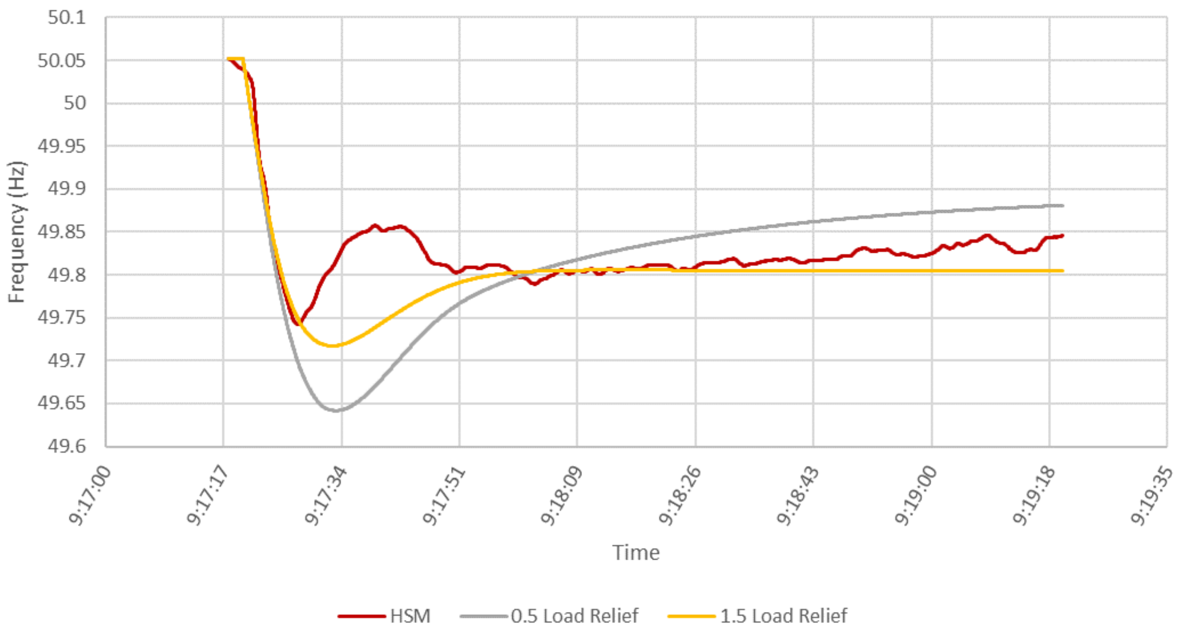


For any given event, it would be expected that the amount of PFR would exceed the amount procured through the market system. This PFR may come from generators not selected for FCAS or from additional provision from FCAS selected generators. For comparisons to past events, only the amount of reserve available through FCAS was modelled, as there is not good visibility of the reserve delivered in addition to this. As only the volume of reserve procured from the market has been modelled, at a base performance level, the modelled response is expected to show lower frequency nadirs than the real events.

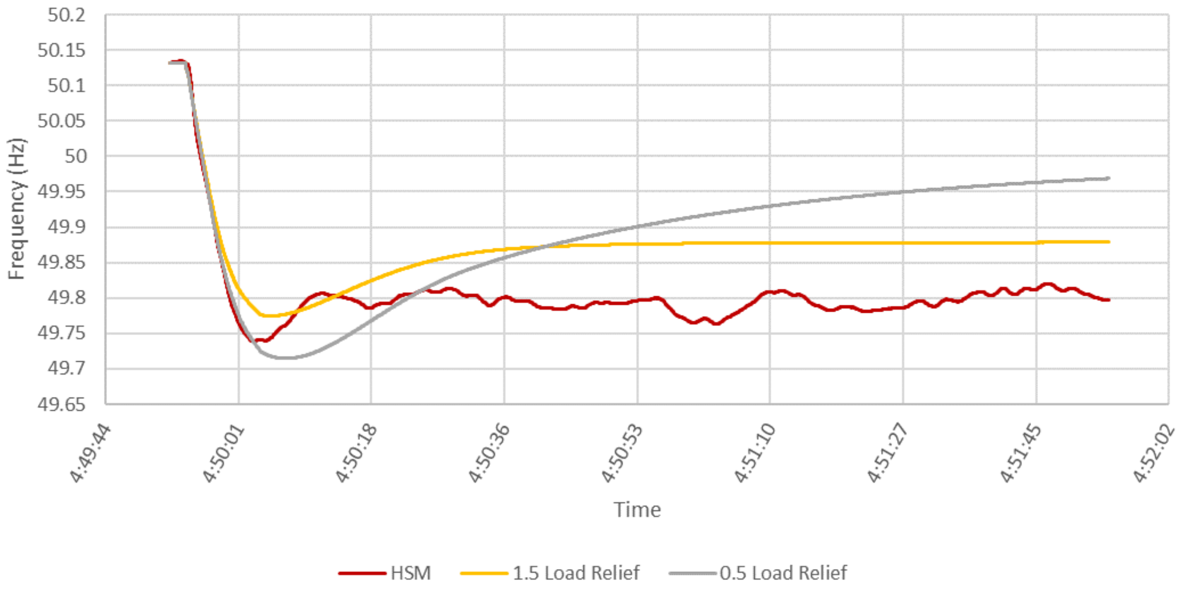
Overlays of the modelled response to the real events provide a comparison point to the level of conservatism in the modelling, and an indication of what outcomes could be expected if the decline in PFR was to continue. This is different to system frequency models that model the quality and quantity of reserve available on each individual unit for a provided dispatch. These more sophisticated models are suitable for being validated against real events and being progressively revised to then be able to provide a good predictor of post-event frequency outcomes.

Modelled results are shown below using values of 1.5 pu/pu (per unit load /per unit frequency) and 0.5 pu/pu for load relief. The 1.5 pu/pu value was used in the setting of the reserve level at the time of the events. The 0.5 pu/pu value is an updated load relief value now considered a more appropriate representation for the NEM. While the higher load relief values show a closer match to the measured frequency nadir, this is mainly attributable to additional PFR being provided outside of FCAS procurement.

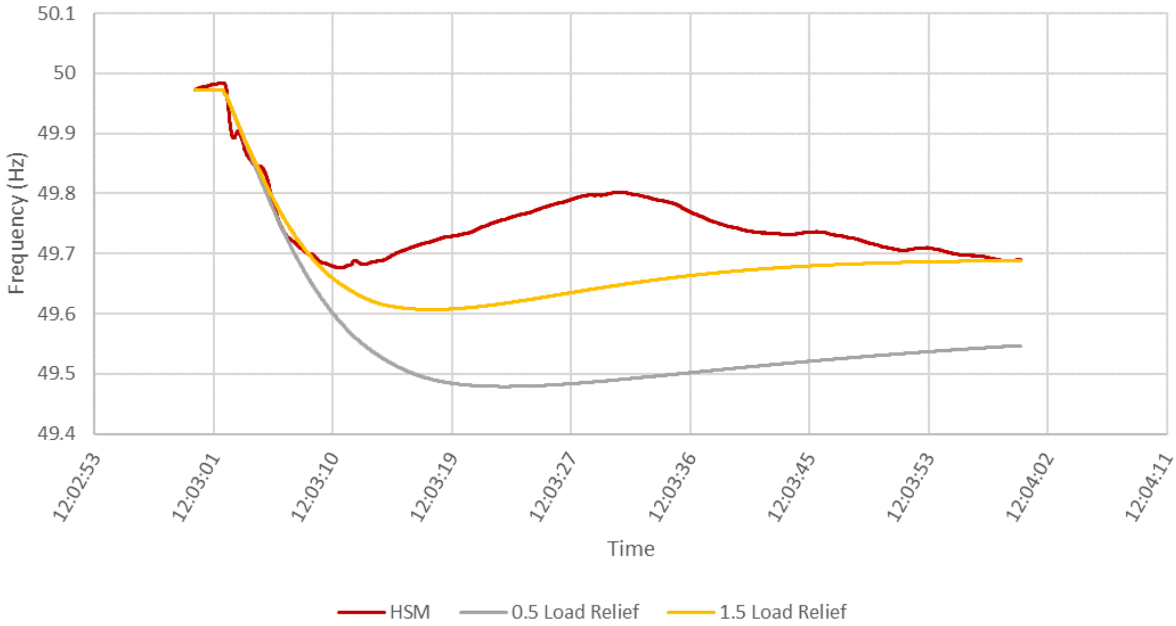
Event 1: 23/12/2018 09:17 trip of Liddell



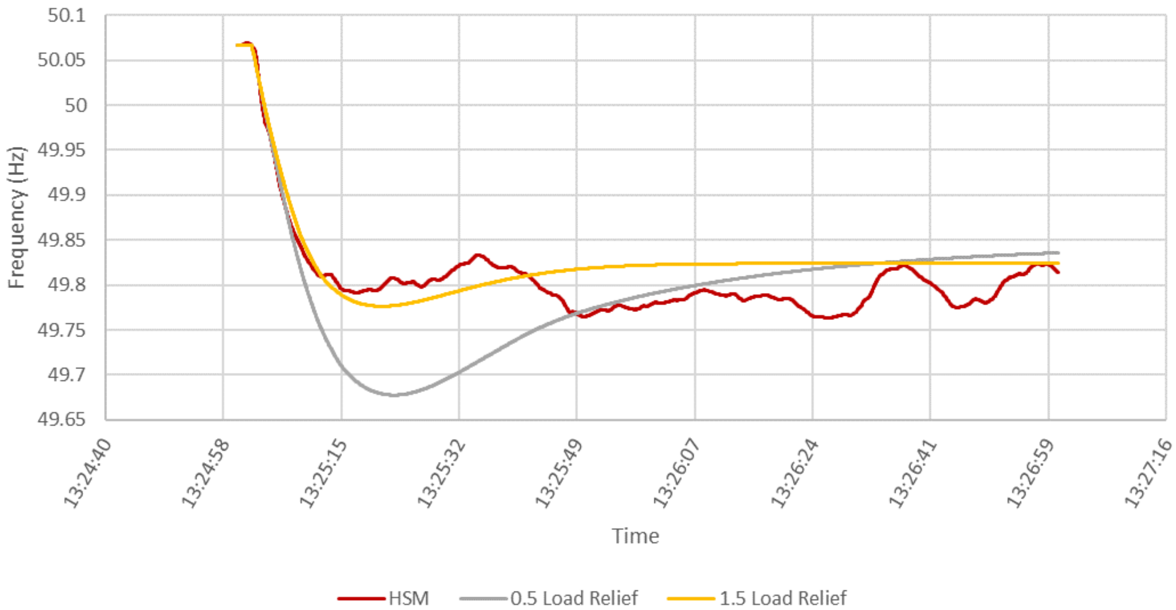
Event 2: 27/1/2019 04:49 trip of Bayswater



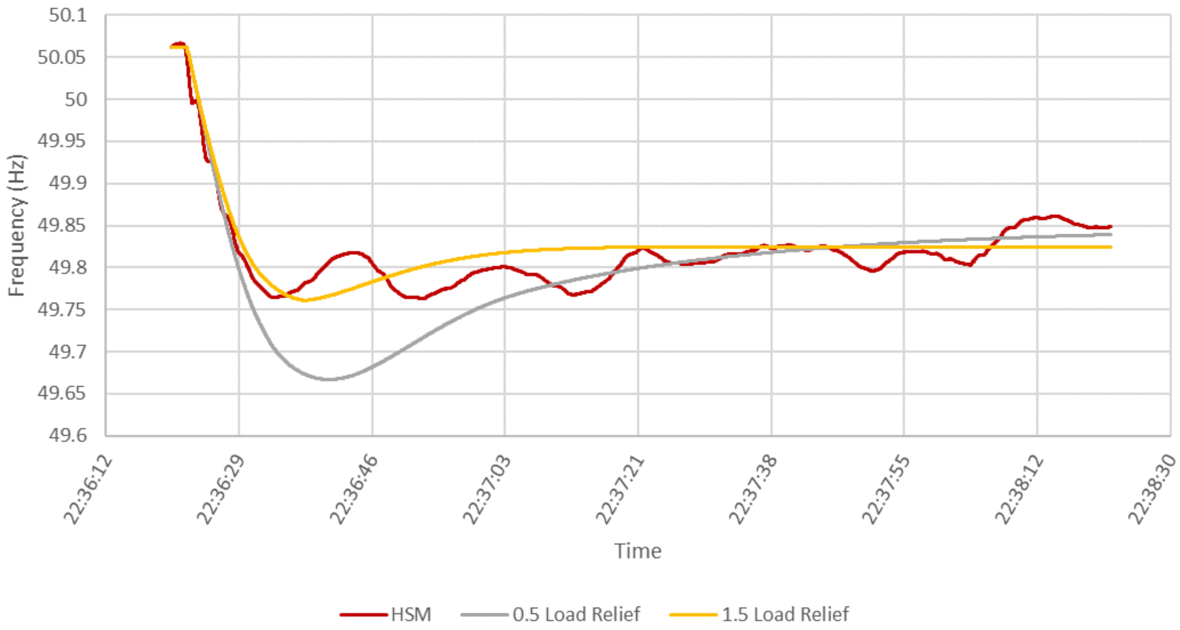
Event 3: 25/2/2019 12:03 trip of Newport



Event 4: 19/2/2019 13:24 trip of Callide B



Event 5: 5/2/2019 22:36 trip of Tallawarra



Event 6: 28/12/2019 00:43 trip of Bayswater