AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

Separation leading to under-frequency in South Australia

May 2023

Key observations and proposed management measures

A report for the National Electricity Market

Important notice

Purpose

This report presents results and conclusions from a suite of studies relating to the non-credible separation of South Australia from the rest of the National Electricity Market power system, undertaken following a recommendation from AEMO's 2020 Power System Frequency Risk Review.

This publication is generally based on information available to AEMO as at December 2022 unless otherwise indicated.

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Version control

Version	Release date	Changes
1	19 May 2023	First release

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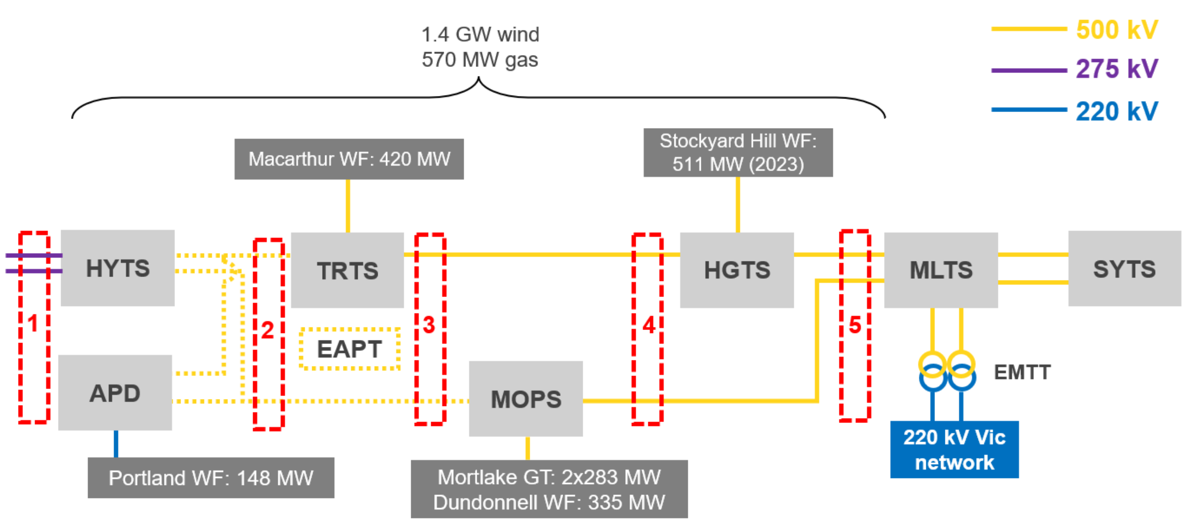
Executive summary

This report presents the results and conclusions from AEMO's studies relating to specified scenarios involving the non-credible separation of South Australia from the rest of the National Electricity Market (NEM) power system. The studies described in this report were undertaken following a recommendation, initially in the 2020 Power System Frequency Risk Review, to request the Reliability Panel to declare the non-credible separation as a protected event under the National Electricity Rules (NER)[1,2,3].

Based on the study outcomes, AEMO has identified a number of preferred management actions for containment, stabilisation and recovery of extreme under-frequency for the separation events studied, and will not submit a protected event request to the Reliability Panel at this time.

The contingency events studied in this report are the double-circuit trip of the lines illustrated in Figure 1, leading to synchronous separation of South Australia from the rest of the NEM, under power system conditions resulting in under-frequency in South Australia. All studies in this report relate to the period prior to commissioning of Project EnergyConnect Stage 2.

Figure 1 South Australia separation points studied in this analysis, numbered [1] to [5]



[1]: Heywood - South East (HYTS - SESS) 275 kilovolt (kV) lines.
[2]: Heywood – Alcoa Portland - Mortlake (HYTS - APD - MOPS) 500 kV line and Heywood - APD - Tarrone (HYTS - APD - TRTS) 500 kV line.
[3]: Heywood - APD - Mortlake (HYTS - APD - MOPS) 500 kV line and Tarrone - Haunted Gully (TRTS - HGTS) 500 kV line.
[4]: Tarrone - Haunted Gully (TRTS - HGTS) 500kV line and Mortlake - Moorabool (MOPS - MLTS) 500 kV line.
[5]: Moorabool - Haunted Gully (MLTS - HGTS) 500 kV line and Moorabool - Mortlake (MLTS -MOPS) 500 kV line.

WF: Wind farm
GT: Gas turbine

[1] AEMO (July 2020), *2020 Power System Frequency Risk Review – Stage 1*, Appendix A1, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-1/psfrr-stage-1-after-consultation.pdf?la=en&hash=A57E8CA017BA90B05DDD5BBBB86D19CD.

[2] AEMO (December 2020) *Power System Frequency Risk Review – Stage 2 Final Report*, https://aemo.com.au/-/media/files/initiatives/der/2020/2020-psfrr-stage-2-final-report.pdf?la=en&hash=9B8FF52E750F25F56665F2BE10EBFDFA.

[3] AEMO (July 2022) *Power System Frequency Risk Review Final Report*, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en&hash=79BE593AE07E51B7E8129210D45840A6.

The basis for the original studies was that increasing distributed PV (DPV) is reducing the effectiveness of the under-frequency load shedding (UFLS) scheme in South Australia to arrest severe under-frequency events. Total UFLS load in South Australia reached a minimum of -110 megawatts (MW) in spring 2021, and was below 200 MW for 2% of 2021-22. Deterioration of UFLS capability may result in increased risks of cascading failure following contingency events in South Australia.

Separations at locations [1], [2] and [5] in Figure 1 have occurred in the last five years. Based on these historical observations, non-credible separation events that are in-scope for this report are assumed to occur approximately 0.6 times per year (approximately three events every five years).

Out of scope

The following were considered out of scope for the present series of studies:

- Separation events leading to over-frequency in South Australia. Power system studies indicate further complicating factors for these types of separation events, which the proposed risk management measures in this report are not designed to address.
- Separation events at other network locations, including other possible locations in the 275 kilovolt (kV) South Australian network, or other possible separation points in South-West Victoria. These have not been studied in this proposal.
- Separation events occurring following the full commissioning of Project EnergyConnect (PEC) Stage 2. The proposed management measures are defined to be effective only until full commissioning of PEC Stage 2.

Scenarios

Studies were conducted based on interconnector flows and generator dispatch outcomes from AEMO's 2022 *Integrated System Plan* (ISP)[4], using dispatch outcomes from a Plexos market model for every 30-minute interval in the two financial years 2022-23 and 2023-24. The analysis considered two forecast dispatch patterns:

- **2 x synchronous generator requirement** – present minimum two synchronous generating unit requirement is sustained in South Australia. A minimum of at least two synchronous generating units is maintained online in South Australia in all periods, noting that many periods will feature more synchronous units online where this is the least-cost dispatch to meet demand.
- **No synchronous generator requirement** – the existing minimum two synchronous generating unit requirement is removed. Dispatch patterns may include periods with no synchronous units online in South Australia, but also features various numbers of synchronous units online in many periods when this is the least-cost dispatch outcome.

Proposed management measures were designed to be robust in both scenarios.

These studies do not make any assessment of the ability to operate South Australia with no synchronous generating units online, beyond simple frequency dynamics following a non-credible separation. This is being investigated in a parallel workstream.

[4] AEMO 2022, https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

Models applied

Selected studies were conducted in a root mean square (RMS) model for a separation at Heywood (point [1] in Figure 1) and Moorabool (point [5]) under a range of conditions. The RMS models were based on historical snapshots with a full network representation of the NEM. These studies were used to benchmark a simplified multi-mass model (MMM) representation of the South Australian power system, which allows rapid testing of many trading intervals, to facilitate cost/benefit assessments. Benchmarking indicates that the MMM provides a fair representation of system frequency for separation events leading to under-frequency in South Australia.

The MMM representation does not include any direct representation of system strength, voltage or reactive power, and was only applied to model conditions where the RMS studies showed relatively simple frequency dynamics without these complicating factors.

Influential assumptions

RoCoF withstand capabilities

An extreme rate of change of frequency (RoCoF) can be experienced in South Australia following a non-credible separation. Large synchronous generating units, particularly gas turbines, can demonstrate a range of issues for RoCoFs exceeding ±1-2 hertz per second (Hz/s). AEMO requested information from power station operators on the RoCoF withstand capabilities of key synchronous generators in South Australia, examined unit behaviours in previous historical events, and reviewed international experiences. Two wind farms in South Australia were identified to have explicit RoCoF protection, which was included directly in all studies.

Pelican Point Combined Cycle Gas Turbine (PPCCGT) is noted as the highest priority as it may have a relatively higher risk of tripping in response to extreme RoCoF in the ranges observed in these studies, and is large enough to influence power system outcomes in South Australia following a non-credible separation. This analysis used a base assumption that PPCCGT will trip if RoCoF exceeds an average of ±2 Hz/s for more than 100 milliseconds (ms), but also modelled sensitivities with a range of additional PPCCGT RoCoF withstand capabilities. It is noted that there is significant uncertainty regarding the RoCoF withstand capabilities of all units.

Tripping behaviours

The detailed models provided to AEMO to represent Lake Bonney Wind Farm 1-3 (LKB1-3) and Canunda Wind Farm (CNUN) in electromagnetic transient (EMT) power system studies show that they may trip following a separation event[5]. For these studies, it has been assumed that these units will trip 200 ms following a separation event. A sensitivity where the wind farms remain connected has also been modelled.

Control schemes

For separation events in the 500 kV South-West Victoria network, there are a number of control schemes that influence power system outcomes. These include the following, which were represented in the studies:

- The South-West Victoria Generator Fast Trip (SWV GFT) scheme[6].

[5] AEMO, *Transfer Limit Advice – System Strength in SA and Victoria*, April 2023, Section 2.2, https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

[6] The SWV GFT is designed to prevent voltage collapse or instability due to very low system strength in the 500 kV South-West Victoria network post-separation. Following a separation at point [5], the SWV GFT trips Stockyard Hill and Dundonnell Wind Farms. Following a separation at point [4] (see Figure 1), the SWVV GFT would trip Dundonnell WF only, due to the location of the separation.

- The Emergency APD Potline Tripping (EAPT) control scheme[7].

Acceptance criteria

The analysis was conducted in two parts:

- **Frequency containment** – assessment of the ability to contain frequency in the first 60 seconds following separation. Scenarios were considered a "fail" outcome if frequency fell below 47.6 Hz, and a "risk" outcome if frequency fell below 48 Hz.
- **Frequency stabilisation and recovery** – assessment of the ability to stabilise and recover frequency in the 10 minutes following separation. Scenarios were considered a "fail" outcome if they did not reach 49 Hz within two minutes of separation and 49.5 Hz within 10 minutes of separation, or a "risk" outcome if they did not recover to 49.75 Hz within 10 minutes.

This report does not make any assessment of the ability to operate the South Australian island in the period following the first 10 minutes after a non-credible separation event.

Frequency containment: expected power system outcomes

Frequency containment studies identified a range of different factors that contribute to power system risks, as summarised in Table 1. Multiple risk factors can apply in the same period.

Table 1 Contributing risk factors identified

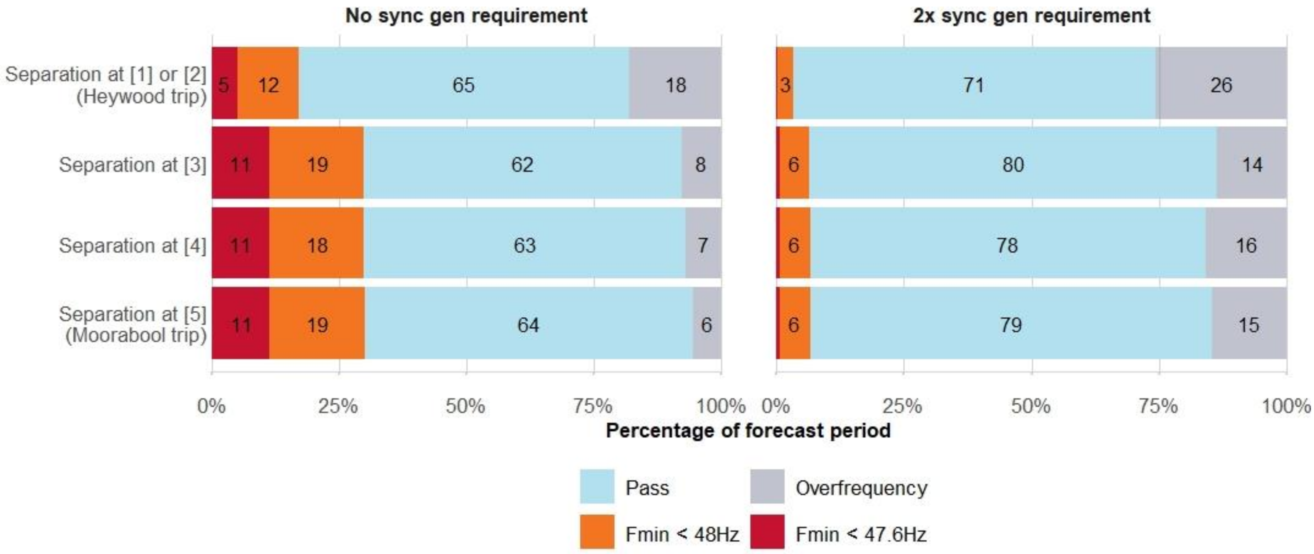
Risk factor (multiple risk factors may be present in a single period)		Description	% of 2022-23 and 2023-24 demonstrating this risk factor ('risk' or 'fail' outcomes)			
			Separation at [1] or [2]		Separation at [3], [4] or [5]	
			2x sync gen requirement	No sync gen requirement	2x sync gen requirement	No sync gen requirement
1	Low UFLS load	High generation from distributed PV (DPV) and low UFLS load means that even moderate imports into South Australia can lead to risk/fail outcomes.	1%	3%	As for separation at [1] or [2]	
2	High import with degraded UFLS or low inertia	During periods of high import into South Australia, although UFLS load is only partially affected by DPV generation, the very large size of the original contingency event overwhelms the degraded capability of the scheme, leading to cascading failure.	1%	11%	As for separation at [1] or [2]	
3	Extreme RoCoF leading to synchronous unit trip (Modelling assumes PPCCGT trips if RoCoF exceeds 2 Hz/s for ≥100 ms)	When synchronous units vulnerable to high RoCoF are online and imports are high, RoCoF following separation can exceed the assumed withstand capability of the units, leading to a unit trip and cascading failure.	0.5%	5%	4%	19%

[7] The EAPT scheme is designed to secure the system against separation of the 500 kV network between Moorabool (MLTS) and Heywood (HYTS) terminal stations and prevent the Alcoa Portland Smelter (APD) load in Victoria from remaining connected to an islanded South Australia system. The scheme acts to disconnect HYTS from the South-West Victoria 500 kV network. Benchmarking studies between RMS models and the MMM were used to develop the MMM EAPT model. A RoCoF proxy was developed, which activates the MMM EAPT within 190-210 ms following a separation if RoCoF exceeds 2 Hz/s (100 ms average). Further details on the EAPT scheme are in AEMO, *Final Report – Queensland and South Australia system separation on 25 August 2018*, Section 3.4, January 2019, 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.

Risk factor (multiple risk factors may be present in a single period)		Description	% of 2022-23 and 2023-24 demonstrating this risk factor ('risk' or 'fail' outcomes)			
			Separation at [1] or [2]		Separation at [3], [4] or [5]	
			2x sync gen requirement	No sync gen requirement	2x sync gen requirement	No sync gen requirement
4	Generation trip exacerbates contingency (Modelling assumes LKB 1-3 and CNUN WF trip 200ms after separation)	EMT models provided to AEMO show that Lake Bonney 1-3 (LKB1-3) and Canunda (CNUN) wind farms may trip following separation events when operating above certain thresholds. There is also a set of wind farms tripped by the SWV GFT for separations at [4] or [5] (see Figure 1), to manage system strength issues. When wind generation is high, the trip of these wind farms following a separation event can exacerbate a contingency and contribute to risk/fail outcomes.	2.5%	10%	6%	26%
5	Interconnector flows exceeding thresholds	Interconnector flows can exceed existing limits due to drift (movements in load or generator levels within trading intervals) or timestep issues (constraints use the inertia level from the preceding interval).	Not quantified in these studies			
6	Over frequency (up to 26% of trading intervals in 2022-23 to 2023-24)	Separations at Heywood leading to over-frequency (typically when exporting from South Australia) have been identified to lead to instabilities on the Queensland – New South Wales Interconnector (QNI) and other complicating factors which require further analysis and are excluded from the scope of studies in this report.	Not quantified in these studies (out of scope)			

Figure 2 shows the expected total percentage of time at risk ('risk' or 'fail' based on defined acceptance criteria, shown respectively in orange and red in the figure), amalgamating all the identified risk factors, and accounting for where multiple risk factors may be present in a single five-minute trading interval.

Figure 2 Percentage of periods at risk (2022-23 and 2023-24) following a non-credible separation event (frequency containment)



The associated estimate of unserved energy (USE) is summarised in Table 2. These estimates are based on the estimated likelihood of a non-credible separation event at the relevant locations (0.4 to 0.8 per year), the likelihood of a cascading failure following separation in each period (assumed to be 100% for a “fail” outcome and 50% for a “risk” outcome), and the range of plausible USE associated with a black system event. Annual costs are based on the Value of Customer Reliability (VCR) determined by the Australian Energy Regulator (AER)[8]. Cost estimates based on 2 x VCR are also included, as an additional reference to account for the escalated inconvenience and costs to customers from long duration outages.

Table 2 USE estimates for frequency containment

	Separation at [1] or [2]			Separation at [3], [4] or [5]		
	USE (megawatt hours [MWh]/year)	Annual cost ($ million/year)		USE (MWh/year)	Annual cost ($ million/year)	
		Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement	167 - 741	$8 - $36	$16 - $73	310 - 1,375	$15 - $68	$30 - $135
Minimum 2 synchronous unit requirement	26 - 116	$1 - $6	$3 - $11	53 - 236	$3 - $12	$5 - $23

Management options – Frequency containment

The possible management options considered for frequency containment are summarised in Table 3.

Table 3 Management options for frequency containment

Options	Details	Recommendation	
Option 1: Restore UFLS or increase Emergency Under Frequency Response (EUFR)	Take actions to restore UFLS or develop alternative sources of EUFR, as far as technically and economically feasible.	✓	• AEMO has already recommended this action to SA Power Networks (SAPN) and ElectraNet (as far as technically and economically feasible) • This work is already underway, and falls under existing network service provider (NSP) responsibilities defined in NER S5.1.10.1(a). • This cannot be fully addressed quickly, so other management measures are proposed below as a stop-gap measure. As EUFR is restored, these other management measures are designed to progressively ease.
Option 2: Constrain Heywood imports	Constrain imports into South Australia during high-risk periods: • where there is insufficient emergency under-frequency response (including UFLS) to manage a clean double-circuit separation at [1] or [2], or • if RoCoF post-separation might exceed the withstand thresholds for units online.	✓	• Effective constraints are currently implemented under regulation 88A of the South Australian *Electricity (General) Regulations 2012* (Regulation 88A)[A] to limit RoCoF in South Australia to 3 Hz/s for a non-credible loss of the Heywood Interconnector. • Constraint formulations have been reviewed based on latest forecasts and system conditions, with fine tuning proposed to maintain efficacy.
Option 3A: Physical testing of synchronous unit RoCoF withstand capabilities	Explore feasibility of physical testing of selected synchronous generating units to develop more insight into RoCoF withstand capabilities. PPCCGT is noted as the highest priority.	?	• Noting the plant age, technology and modelling capability[B], investigate feasibility of testing as a first step, exploring costs, expected timelines, and the level of confidence in RoCoF withstand capabilities that could be achieved by testing.

[8] $43.23/kWh for the SA region in 2019 (indexed by CPI to $49.14/kWh as at December 2022). From AER 2019, *Values of Consumer Reliability – Final Decision*, Table 5.22, available at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf.

Options	Details	Recommendation	
Option 4: Modification to control schemes in South-West Victoria	Explore several options to modify control schemes in the South-West Victoria network to better manage the brief period of extreme RoCoF that can occur following non-credible separation events at [3], [4] or [5].	✘	• Modifications to EAPT scheme unlikely to result in reduced risk and may have unintended consequences. • Selective disarming of SWV GFT scheme infeasible since this is required to manage system strength issues. • Do not recommend.
Option 5: Address RoCoF protection on wind farms	Remove/replace specific RoCoF anti-islanding protection on two wind farms in South Australia	✘	• Studies indicate this does not materially reduce risk. • Do not recommend.
Option 6: Address generation tripping	Identify and if possible address the cause of LKB and CNUN wind farm instability and tripping behaviour demonstrated in EMT models (provided to AEMO)[C] following separation events when operating above thresholds.	✘	• Unit operators advise they have already extensively explored options to investigate and address this behaviour. • Tripping behaviour is assumed in design of other management measures proposed; if this tripping behaviour can be rectified then other management measures can be eased, reducing system costs.
Option 7: Constrain imports in South-West Victoria	Explored implementation of a constraint that reduces network flows in South-West Victoria to reduce RoCoF following a non-credible separation at [3] to below thresholds that might lead to synchronous generator tripping in South Australia.	✘	• High market cost. By constraining network flows, the constraint acts to dispatch down lower cost generation in Victoria, typically replaced with higher cost gas-fired generation in South Australia. • Do not recommend.
Option 3B: Constrain RoCoF-vulnerable generating units	Implement a constraint that reduces dispatch of units identified to be vulnerable to extreme RoCoF to minimum generation in periods where there is a risk of unit trip following a separation in the South-West Victoria network. This aims to minimise likelihood of cascading failure in the event of a unit trip. Designed to complement constraints on Heywood imports (Option 2). This does not completely remove security risks, but reduces them significantly.	✘	• Directly constraining synchronous units to minimum generation has a relatively lower cost than constraining network flows in South-West Victoria. The constraint typically replaces unit generation with similar cost generation in South Australia. • Do not recommend implementing based on present evidence available. The constraint demonstrates a positive cost/benefit for the assumed PPCCGT RoCoF withstand capabilities (trip for RoCoF>±2 Hz/s for 100 ms), but actual RoCoF capability is highly uncertain. Actual benefits are unknown. • Could be implemented in future if further evidence indicates this would be beneficial.

A. Regulation 88A was introduced by the *Electricity (General) (Provision of Limit Advice) Variation Regulations 2016*, No 240 of 2016.
B. Associated with the challenge of undertaking detailed modelling of electrical and mechanical components to evaluate generator ride-through performance for large RoCoF events.
C. AEMO, *Transfer Limit Advice – System Strength in SA and Victoria*, April 2023, Section 2.2, https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

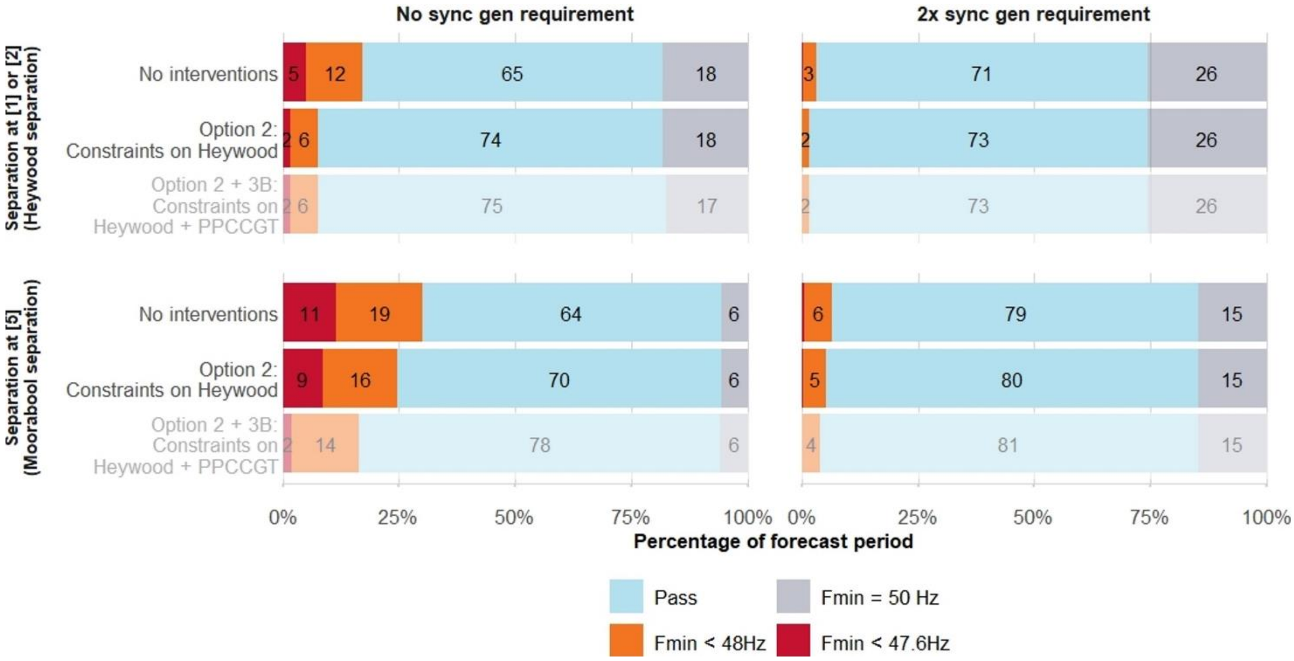
Figure 3 shows the expected improvement in power system security outcomes for Option 2 (constrain Heywood imports) and Option 3B (constrain RoCoF-vulnerable units). Option 2 is designed to manage risks for separations at [1] and [2], while Option 3B is designed to manage risks for separations at [3], [4] or [5]. Option 3B is not recommended at this time due to uncertainties around RoCoF ride-through capability. The analysis in Figure 3 is based on the assumption that PPCCGT will trip if RoCoF exceeds ±2 Hz/s for ≥100 ms, and is provided for illustration only.

Option 2 and Option 3B both demonstrate a positive cost/benefit, as summarised in Table 4. The constraints will bind less frequently and incur less costs if the other recommended measures can be progressed (such as increasing Emergency Under Frequency Response [EUFR]).

Risks appear low in the scenario where the 2 x synchronous generating unit requirement is maintained. It is noted that the incidence of high risk dispatch outcomes in the 2 x synchronous generator scenario may not be well captured by Plexos model forecasts. In the no synchronous generator requirement scenario, up to 22% of periods show risk and fail outcomes when there is one or more synchronous units online, indicating that risks can arise even in periods with synchronous units online.

It is intended that Option 2 be implemented regardless of outcomes in the parallel workstream investigating minimum synchronous generating unit requirements in South Australia. The Option 2 constraints are designed to only bind when high risk dispatch outcomes arise, and bind rarely if these types of dispatch periods do not occur. The proposed constraints demonstrate a positive cost/benefit outcome in both forecast dispatch scenarios.

Figure 3 Impact of quantifiable management options – % of 2022-23 and 2023-24 at risk following non-credible separation



Note: outcomes are shown for a separation at [5]. System security risks are similar for separations at [3], [4] or [5].

Some residual risk periods remain even with the application of the proposed constraints. In these residual risk periods, analysis indicates a reasonable likelihood that South Australia will not meet the frequency containment targets in the Frequency Operating Standard (FOS) for multiple contingency events in an interconnected system, even with the management measures proposed. More aggressive management measures (such as more heavily binding system constraints, incurring higher costs) would be required to address all identified risk periods.

The overall cost/benefit calculation for the combined constraints is shown in Table 4, with the central scenario-weighted net benefit value shown in bold. Constraint costs have been estimated based on a merit order algorithm. Constraint benefits have been estimated in terms of reduced risk of cascading failure in South Australia following a separation. This impact is quantified as annual reduction in USE.

This analysis indicates that these constraints demonstrate a central estimate with net positive benefit across both forecast scenarios assessed. At this time, AEMO recommends implementing Option 2 (constraints on Heywood), but does not recommend Option 3B (in grey in Table 4) due to the significant uncertainty on the unit RoCoF withstand capabilities which make it difficult to confirm the benefits.

Table 4 Costs and benefits for Option 2 (+ Option 3B): Constraint on Heywood imports (and specific generating units), 2022-23 and 2023-24

		Reduction in USE from constraints (MWh/year)	Estimated benefits ($mil/year)		Estimated costs ($mil/year)	Estimated net benefit ($mil/year)	
			Standard VCR	2 x VCR		Standard VCR	2 x VCR
Option 2 (Heywood constraints)	No minimum synchronous unit requirement	135 to 601	$7 to $30	$13 to $59	$12	-$5 to $18 **Central: $6**	$1 to $47 **Central: $23**
	Minimum 2 synchronous unit requirement	25 to 110	$1 to $5	$2 to $11	$2.4	-$1 to $3 **Central: $0.8**	$0 to $8 **Central: $4**
Option 2 + Option 3B (RoCoF-vulnerable unit constraints)	No minimum synchronous unit requirement	271 to 1,202	$13 to $59	$27 to $118	$17	-$4 to $42 **Central: $18**	$9 to $101 **Central: $53**
	Minimum 2 synchronous unit requirement	35 to 156	$2 to $8	$3 to $15	$3	-$1 to $5 **Central: $2**	$0 to $12 **Central: $6**

Frequency recovery

Historical events have shown that it can take 10 to 15 minutes for AEMO to confirm a non-credible separation and reconfigure the system for islanded operation of South Australia. This means that during the first 10 to 15 minutes following a non-credible separation event, before the necessary elements are reconfigured, frequency control is largely reliant on the automatic responses of resources within the South Australian island.

The FOS specifies, on a reasonable endeavours basis, that frequency should be stabilised above 49 Hz in two minutes, and recover to above 49.5 Hz in 10 minutes, following a non-credible separation event. This aligns with the continuous operation capabilities defined in the generator performance standards (GPS) of the majority of generating units in South Australia at present, meaning that these units are not required to remain connected beyond these thresholds, and may have explicit protection causing them to trip if these thresholds are exceeded. Some older units (with a total installed capacity of approximately 1.5 gigawatts [GW]) have GPS that only require them to remain connected for eight minutes if frequency is below 49.5 Hz.

A survey of unit operators confirmed that several units do have explicit protection elements to disconnect at or just beyond their limits of required continuous operation. For some units without explicit protection, operators noted that the complex interaction between primary and secondary equipment under these extreme frequency conditions makes it difficult to predict the timeframe and means by which a generating unit may disconnect. Respondents also noted that operation outside their required frequency ranges as defined in their GPS could result in damage to generating units or auxiliary plant, increased maintenance and inspection requirements to maintain reliability, reduced asset lifespan, and insurance risk from operating outside of original equipment manufacturer (OEM) specifications.

This survey indicated a real risk that generating units may trip if these timelines/thresholds are reached or exceeded, and therefore there are real risks to the power system if frequency is not recovered to the specified levels within the time allotted in the FOS for a protected or non-credible separation event. It is not practically feasible to confirm whether sufficient generating units can sustain operation beyond these timelines/thresholds (and make corresponding GPS and protection system adjustments) to allow the FOS limits to be relaxed.

Frequency recovery: expected power system outcomes

Studies indicate two broad types of scenarios that lead to "risk" and "fail" scenarios in the recovery period:

- Moderate or severe contingency events where the frequency nadir is below 49 Hz, and the initial settling frequency is between 49 Hz and 49.5 Hz. Following the interaction of various dynamics in the first 1-2 minutes (including UFLS tripping, frequency response from fast-responding inverter-based resources, responses of synchronous unit governors, and disconnection and reconnection of DPV), frequency settles below 49.5 Hz and there are no further autonomous dynamics to recover frequency in the first 10 minutes. Approximately 80% of the observed risk/fail scenarios are of this type.
- Mild contingency events where the frequency nadir is between 49 Hz and 49.5 Hz. In these events, the initial droop response from generating units assists frequency containment, but in the absence of manual intervention there are no further dynamics to recover frequency in the first 10 minutes. Approximately 20% of the observed risk/fail scenarios are of this type.

Figure 4 shows the proportion of forecast periods showing "fail" outcomes (do not recover to 49.5 Hz in 10 minutes) or "risk" outcomes (do not recover to 49.75 Hz in 10 minutes) following a non-credible separation leading to under-frequency. Over-frequency periods (not illustrated) showed similar outcomes.

Figure 4 Frequency recovery: under-frequency (2022-23 and 2023-24)

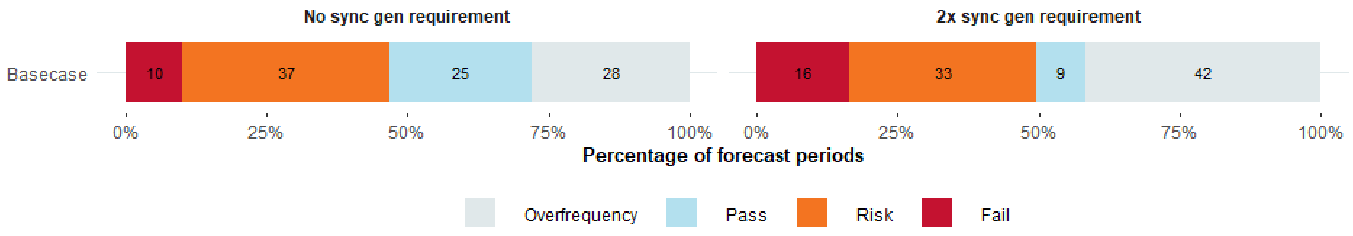


Table 5 shows the USE and annual cost estimates associated with frequency recovery risks. The likelihood of a cascading failure following separation in each period was assumed to be 30% for a "fail" outcome and 1% for a "risk" outcome for under-frequency events. For over-frequency events, the likelihood of a cascading failure following separation was assumed to be 10% for a "fail" outcome and 0.5% for a "risk" outcome. Unit trips in an over-frequency scenario were assigned a lower risk since they may assist frequency recovery, but still have some (small) risk of cascading failure associated with uncoordinated tripping behaviour that could occur simultaneously for a large capacity of generation.

Table 5 USE estimates associated with frequency recovery risks

	Under-frequency events			Over-frequency events		
	USE (MWh/year)	Annual cost ($ million/year)		USE (MWh/year)	Annual cost ($ million/year)	
		Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement	111 - 494	$5 - $21	$10 - $43	20 - 90	$1 - $4	$2 - $8
Minimum 2 synchronous unit requirement	163 - 725	$7 - $31	$14 - $63	34 - 149	$1 - $6	$3 - $13

Studies also showed that frequency recovery risks show little correlation to any discernible pre-event variables (with the exception of extremely mild contingency events where the frequency nadir is above 49.5 Hz). This means that frequency recovery issues must be considered equally likely in any trading interval, and the cost of management measures cannot be minimised effectively via selective enablement of management mechanisms only in certain periods.

Proportional droop response is an important contributor to arresting and stabilising a severe frequency decline immediately following a separation event. However, the studies showed in some cases that an increased amount of proportional response could result in poorer frequency *recovery* outcomes. As frequency begins to recover, proportional droop providers immediately withdraw their response, which counteracts and inhibits frequency recovery. This effect is more pronounced in systems with a large capacity of fast-responding proportional resources because they respond quickly enough to displace UFLS, which delivers a switched (sustained) response that does not withdraw as frequency recovers.

This means that the growing capacity of inverter-based resources in South Australia (particularly battery energy storage systems [BESS] which typically have a fast proportional response enabled and are often dispatched with both headroom and footroom available) is likely to significantly assist with frequency containment, but also may detrimentally affect frequency recovery dynamics, unless management measures are introduced.

Management options – Frequency recovery

The management options considered for improving frequency recovery outcomes are summarised in Table 6.

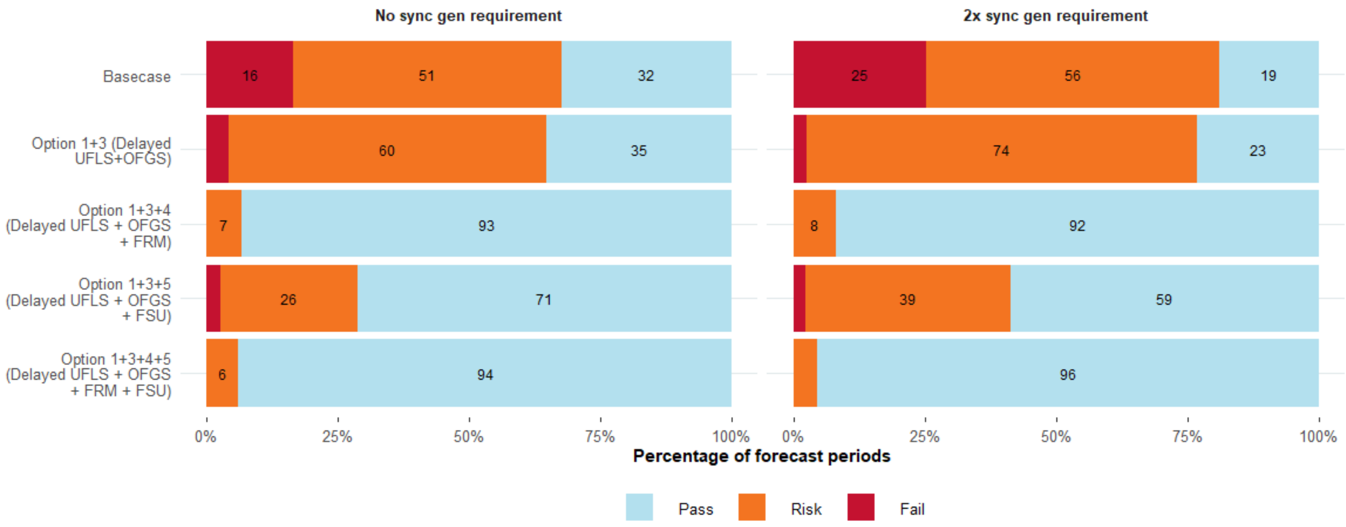
Table 6 Management options for frequency recovery

Options	Details	Recommendation	
Option 1: Delayed UFLS	Expand delayed UFLS scheme to include an average of 120 megawatts (MW) of total load	✓	• AEMO has already recommended this action to SAPN. • Falls under existing NSP responsibilities defined in NER S5.1.10.1(a).
Option 2: Modification of existing UFLS bands	Reduce number of UFLS bands while maintaining total load on the scheme	✗	• Do not recommend. • Less improvement and less robust than other options and increases risk of frequency overshoot.
Option 3: Delayed OFGS	Frequency may settle above 50.5 Hz if there is overshoot following an underfrequency event. Introduce delayed over-frequency generation shedding (OFGS) scheme with four blocks (~120 MW wind capacity each block). Also addresses over-frequency cases following separation.	✓	• AEMO and ElectraNet are collaborating on implementation • Falls under existing NSP responsibilities.
Option 4: Frequency Recovery Mode (FRM)	Implement “Frequency Recovery Mode” (FRM) on 400 MW of proportional resources, to assist frequency recovery and offset detrimental withdrawal as frequency recovers.	(✓)	• Explore potential for implementation on new or existing units (especially BESS in South Australia). • AEMO is working with ElectraNet on implementation pathways.
Option 5: Fast start units (FSU) energy injection	Introduce control schemes on ~100 MW of fast start units (FSU) to automatically detect extended under-frequency, synchronise and ramp up.	(✓)	• Explore implementation if FRM cannot be feasibly implemented on 400 MW of capable units.
Option 6: Introduce local Delayed FCAS requirements	Introduce requirements for Delayed frequency control ancillary services (FCAS) in South Australia in all periods.	✗	• Do not recommend. • May not reliably deliver the required response. • Higher costs than other options.

This combination of services results in a robust solution that will effectively recover frequency under a variety of operating conditions and resource availabilities. Delayed UFLS and OFGS can be implemented relatively quickly, and address a large proportion of the highest risk cases. As more fast acting proportional response is added to the network, delayed UFLS is expected to become less effective. Implementing Frequency Recovery Mode (FRM) on 400 MW of capable units provides a comprehensive long-term solution. If implementation of FRM on 400 MW of capable units is not feasible, fast start units can provide an alternative.

Figure 5 shows the frequency recovery outcomes for all cases (both import and export periods), with the recommended options implemented in a progressive stacking. Implementation of the recommended options (1+3+4) reduces fail cases from 16-25% of all periods to 0% and risk cases from 51-56% to 7-8% of all periods.

Figure 5 Effectiveness of frequency recovery mitigation options



The total estimated benefits of the recommended options combined (Option 1+3+4) in terms of the reduction in USE are summarised in Table 7. Quantification of costs requires further investigation.

Table 7 Estimated benefits of combined recommended options (2022-23 and 2023-24): Option 1+3+4

	Under-frequency cases only			Including over-frequency cases		
	Reduction in USE (MWh/year)	Estimated benefits ($mil/year)		Reduction in USE (MWh/year)	Estimated benefits ($mil/year)	
		Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement	100 - 444	$4 - $19	$9 - $38	120 - 531	$5 - $23	$10 - $46
Minimum 2 synchronous unit requirement	154 - 682	$7 - $29	$13 - $59	186 - 827	$8 - $36	$16 - $72

Next steps

Following the analysis outlined in this report, AEMO has decided not to further progress a request for declaration of the non-credible separation of South Australia as a protected event. All the recommended actions identified in these studies can be implemented without declaration of a protected event, and can be expected to minimise the identified power system risks associated with extreme under-frequency to non-material levels. Conversely, the declaration of a protected event could require additional measures to address the broader aspects of power system security envisaged by the NER for those events, which may not be justified or prudent at this time.

As outlined in Table 3 and Table 6, AEMO intends to continue restoring UFLS and increasing EUFR, managing periods of inadequate UFLS through Heywood constraints, and implementing delayed UFLS and OFGS for frequency recovery. AEMO intends to work with market participants to further examine the feasibility of RoCoF testing for synchronous units and frequency recovery mode (FRM) on BESS in South Australia.

Contents

Tables

Figures

1 Introduction

AEMO's studies show that distributed PV (DPV) reduces the effectiveness of the under-frequency load shedding (UFLS) scheme in South Australia to arrest severe under-frequency events. This is due to a combination of several impacts:

- **Reducing net load** – increasing levels of generation from DPV reduces 'net' load on UFLS load circuits. Total UFLS load in South Australia reached a minimum of -110 megawatts (MW) in spring 2021, and was below 200 MW for 2% of 2021-22.
- **Reverse flows** – in the absence of intervention, the action of UFLS relays to trip load circuits operating in reverse flows will exacerbate an under-frequency event, rather than helping to correct the disturbance. In calendar year 2022, total distribution-connected[9] UFLS load in South Australia was below 0 MW for ~90 hours in the year, and many individual circuits were in reverse flows for longer periods.
- **DPV disconnection** – it is estimated that up to 12% of DPV systems installed in South Australia at present may demonstrate under-frequency disconnection behaviour when frequency falls below 49 hertz (Hz)[10]. This means a severe under-frequency event can be exacerbated by the disconnection of DPV that trips at the same time as UFLS stages. This exacerbates the size of the contingency event, further increasing the probability that the UFLS will be inadequate to arrest a severe under-frequency event.

The deterioration of UFLS capability increases the risk of cascading failure events in South Australia. AEMO reported analysis on these effects in the Power System Frequency Risk Review (PSFRR) reports released in July 2020[11], December 2020[12], and July 2022[13]. This report builds on that analysis, focusing on the non-credible separation of South Australia from the rest of the National Electricity Market (NEM) at the Heywood Interconnector and various locations in South-West Victoria, under conditions where this would lead to under-frequency in South Australia.

The studies in this report were undertaken to support the detailed risk, cost and benefit analysis needed before submitting a request to the Reliability Panel to declare the non-credible separation of South Australia as a protected event under the National Electricity Rules (NER). This was a recommendation initially made in AEMO's 2020 Power System Frequency Risk Review (PSFRR), to allow for comprehensive and transparent measures to contain frequency in periods when the UFLS scheme is likely to be inadequate to do so.

[9] Distribution-connected UFLS load in South Australia typically makes up the majority of the region's UFLS load, contributing 85% of UFLS load in low-DPV periods. Transmission-connected UFLS loads are less impacted by DPV generation, but are typically on the lower UFLS trip frequency bands and can vary through the year based on individual requirements of large sites. In 2022, transmission-connected UFLS load was typically 200 MW, but fell below 130 MW in some periods.

[10] AEMO (May 2021), *Behaviour of distributed resources during power system disturbances*, Section 3.1, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[11] AEMO (July 2020), *2020 Power System Frequency Risk Review – Stage 1*, Appendix A1, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-1/psfrr-stage-1-after-consultation.pdf?la=en&hash=A57E8CA017BA90B05DDD5BBBB86D19CD.

[12] AEMO (December 2020), *Power System Frequency Risk Review – Stage 2 Final Report*, Section 6.2, https://aemo.com.au/-/media/files/initiatives/der/2020/2020-psfrr-stage-2-final-report.pdf?la=en&hash=9B8FF52E750F25F56665F2BE10EBFDFA.

[13] AEMO (July 2022), *Power System Frequency Risk Review*, Section 3.3 and Section 7.3, https://aemo.com.au/-/media/files/initiatives/der/2020/2020-psfrr-stage-2-final-report.pdf?la=en&hash=9B8FF52E750F25F56665F2BE10EBFDFA.

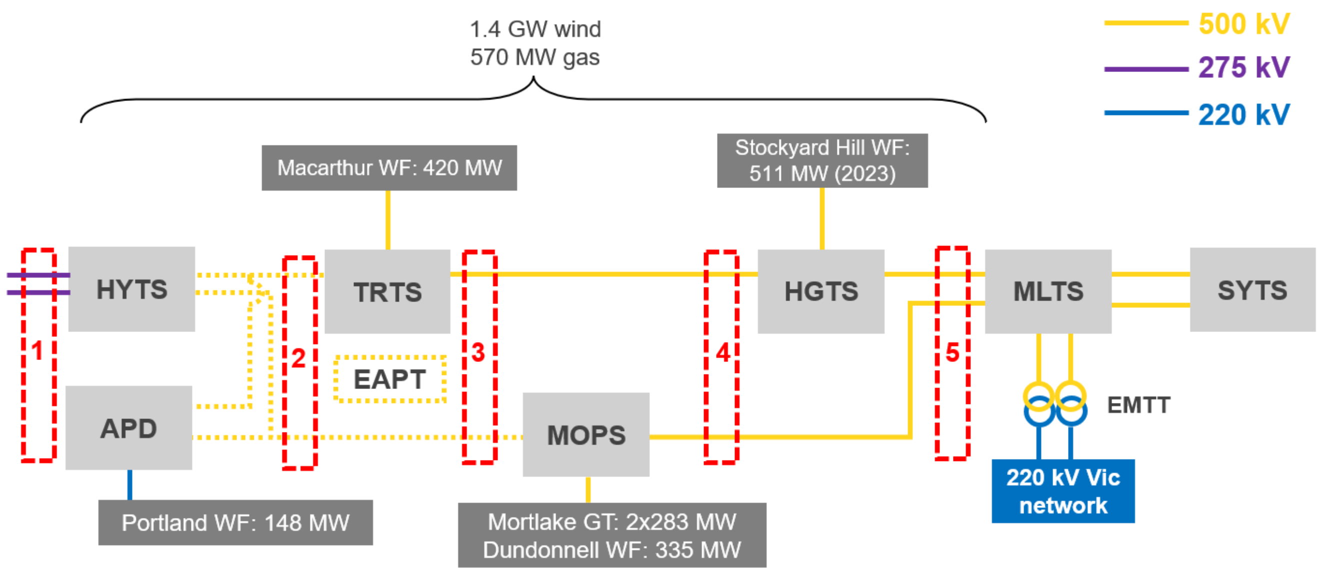
The remainder of this report presents:

- The non-credible (double-circuit) separation events considered, and aspects of those separations outside the scope of the present studies (see Section 2).
- AEMO's assessment of the likelihood of occurrence of those separation events (Section 3).
- AEMO's assumptions and assessment approach (Section 4).
- Under-frequency containment risk analysis for the considered separation events at Heywood (Section 5) and in the South West Victoria network (Section 6) and the recommended management options (Section 7).
- Frequency recovery risk analysis for the considered separation events (Section 8) and recommended management options (Section 9).
- Next steps, including AEMO's decision not to progress a protected event declaration (Section 10).
- Key modelling assumptions (Appendix A1), PSS®E and PSCAD benchmarking studies (Appendix A3), cost benefit assumptions (Appendix A4).
- Detailed risks associated with extreme RoCoF (Appendix A2).

2 Nature of the event

AEMO has studied South Australian separations resulting in under-frequency at the following locations, as numbered in Figure 6. The management measures proposed in this report are designed to manage separations at these locations. Separations at locations [1], [2] and [5] in Figure 6 have occurred in the last five years.

Figure 6 South Australia separation points studied in this analysis, numbered [1] to [5]



[1]: Heywood - South East (HYTS - SESS) 275 kilovolt (kV) lines.
[2]: Heywood – Alcoa Portland - Mortlake (HYTS - APD - MOPS) 500 kV line and Heywood - APD - Tarrone (HYTS - APD - TRTS) 500 kV line.
[3]: Heywood - APD - Mortlake (HYTS - APD - MOPS) 500 kV line and Tarrone - Haunted Gully (TRTS - HGTS) 500 kV line.
[4]: Tarrone - Haunted Gully (TRTS - HGTS) 500kV line and Mortlake - Moorabool (MOPS - MLTS) 500 kV line.
[5]: Moorabool - Haunted Gully (MLTS - HGTS) 500 kV line and Moorabool - Mortlake (MLTS -MOPS) 500 kV line.

WF: Wind farm
GT: Gas turbine

Over-frequency events are out of scope

Separation events under conditions leading to over-frequency in South Australia are out of scope for this analysis. A number of further complicating factors have been identified for over-frequency events (outlined in Appendix A3) which require further analysis to develop suitable management approaches. To separate this work into manageable pieces, allow more expedient implementation of management measures, and facilitate more effective consultation, this report focuses only on separation events leading to under-frequency in South Australia[14], while future work will examine possible approaches for the management of over-frequency events.

The South Australian over-frequency generation shedding (OFGS) scheme has recently undergone review and changes are in the process of implementation.

[14] Including conditions where over-frequency may result from 'overshoot' of under-frequency response.

Separation points that are out of scope

There are other possible points in the network where a non-credible separation could occur between South Australia and Victoria. For example, ElectraNet has identified that there are possible separation points in the South Australian 275 kV network west of point [1] in Figure 6, including:

- South East to Tailem Bend (such as occurred on 12 November 2022[15]).
- Tailem Bend to Tungkillo/Cherry Gardens.

Separation at these points in the South Australian network interacts with the meshed 132 kV network and involves control schemes which have not been directly modelled in this assessment. These are therefore out of scope.

There are also other possible separation points in the 500 kV South-West Victorian network, including between Moorabool (MLTS) and Sydenham (SYTS), east of point [5] in Figure 6. Separation events at these points will interact with the protection in the 220 kV Victorian network and the Emergency Moorabool Transformer Tripping (EMTT) control scheme in complex ways, which are out of scope for the analysis.

These other possible separation points have not been examined in this report in detail. Future analysis may identify further risks associated with these alternative points of separation that require additional management measures.

Project EnergyConnect

The identified risks associated with synchronous separation and measures proposed are designed for implementation in the period prior to full commissioning of Project EnergyConnect (PEC) Stage 2.

The measures proposed here have been designed to continue to apply (with minor adjustments) following commissioning of Stage 1 of PEC. PEC Stage 1 will have a maximum capacity of up to 150 MW and will be designed with an intertrip that opens the PEC Stage 1 circuit approximately 200 milliseconds (ms) following the loss of lines at [1] to [5]. As such, PEC Stage 1 could increase the contingency size associated with a separation by up to 150 MW; this potential impact is studied in a sensitivity summarised in Section 7.9.1. The proposed measures in this study have been confirmed to remain appropriate with PEC Stage 1.

Following the full commissioning of Project EnergyConnect Stage 2, AEMO and the relevant network service providers (NSPs) will be undertaking extensive analysis to identify appropriate management measures to maintain system security in South Australia beyond this time.

Operation of the South Australia island

This analysis only considers the ability to contain, stabilise and recover frequency in the 10 minutes following a non-credible separation event. No consideration has been given to any measures that may be required to successfully operate a South Australia island beyond the first 10 minutes after a separation event.

Focus on frequency dynamics only

This report focuses primarily on frequency dynamics. It does not provide any detailed investigation or commentary into issues such as system strength, voltage management, reactive power management, grid-forming

[15] AEMO (November 2022) Preliminary Report – Trip of South East – Tailem Bend 275kV lines on 12 November 2022, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/preliminary-report--trip-of-south-east-tailem-bend.pdf?la=en.

requirements, or the ability to survive a non-credible separation and operate a South Australian island with no synchronous generating units operating. These issues have been investigated at a high level only (as summarised in Appendix A3) to confirm there are no obvious compounding issues that would invalidate the frequency studies performed. Parallel work streams are underway to investigate these other issues, and may subsequently reveal other power system challenges requiring further management measures.

3 Likelihood of the event

Table 8 provides a summary of South Australian separation events since the start of the NEM in 1998. Causes are widely varied.

For this analysis, the estimated likelihood of a relevant (in scope) separation event was based on:

- Non-credible contingency events,
- Occurring in the relevant network locations ([1] to [5] as defined in Figure 6), and
- Occurring in the past five years (sampling focused on the most recent period, as most relevant to the present power system).

Three events in the past five years meet these criteria. This indicates a likelihood of three separation events in five years, or 0.6 occurrences per year.

For sensitivity analysis, a range was applied to this baseline, considering the possibility of one more or one less event in the relevant network locations, occurring in the five year period. This results in a likelihood range of 0.4 to 0.8 occurrences per year.

Likelihood of non-credible SA separation

- Central assumption: 0.6 occurrences per year (three events in five years)
- Sensitivities: 0.4 to 0.8 occurrences per year (two to four events in five years)

Table 8 Historical South Australian separation events

Datetime	Classification	Heywood flow (VIC to SA)	Description	Meets criteria?	Justification
23/10/1999 12:06	Credible	250	Loss of SESS-TBSS 275 kV line while parallel line out of service.	FALSE	Credible contingency
30/10/1999 6:02	Unknown	144	Unknown	FALSE	Outside the timeframe considered
2/12/1999 13:11	Non-credible	490	Loss of 2 x Northern Power Station units within 40 seconds triggered South East Substation (SESS) loss of synchronism (LOS) protection to operate.	FALSE	Outside the timeframe considered
27/05/2003 17:02	Credible	-31	Loss of a HYTS-SESS 275 kV line while parallel circuit out for maintenance.	FALSE	Credible contingency
8/03/2004 11:28	Non-credible	312	Incorrect fast runback of units following fault caused SESS LOS protection to operate.	FALSE	Outside the timeframe considered
14/03/2005 6:39	Non-Credible	431	Incorrect fast runback of units following fault caused SESS LOS protection to operate.	FALSE	Outside the timeframe considered
16/01/2007 15:02	Non-credible	-298	Heywood interconnector LOS protection operated due to oscillations following New South Wales – Victoria separation.	FALSE	Outside the timeframe considered

Datetime	Classification	Heywood flow (VIC to SA)	Description	Meets criteria?	Justification
19/10/2011 06:18	Credible	15	Loss of a HYTS-SESS 275 kV line while parallel circuit out for maintenance.	FALSE	Credible contingency
13/12/2012 07:07	Credible	163	APD protection operated during line switching in preparation for APD-HYTS 2 line outage.	FALSE	Credible contingency
1/11/2015 21:51	Credible	221	Loss of a HYTS-SESS 275 kV line while parallel circuit out for maintenance.	FALSE	Credible contingency
28/09/2016 16:18	Non-credible	508	Repeated South Australia transmission faults triggered large loss of generation in South Australia, leading to sudden increase in HYTS flows and operation of SESS LOS protection, resulting in black system.	FALSE	This mechanism of cascading failure is now managed via the South Australia System Integrity Protection Scheme (SA SIPS) scheme.
1/12/2016 00:16	Credible	217	500 kV line fault in Victoria during prior outage of another line.	FALSE	Credible contingency
25/08/2018 13:11	Non-credible	-170	Loss of the Queensland – New South Wales Interconnector (QNI) due to lightning caused subsequent power swing across HYTS and under-frequency, resulting in operation of EAPT scheme to trip the 500 kV circuits at HYTS.	TRUE	The unexpected operation of a control scheme separating South Australia could lead to cascading failure if repeated while South Australia is importing and has insufficient UFLS.
16/11/2019 18:06	Non-credible	-307	Malfunctioning communication equipment caused the trip of HYTS – APD – MOPS 500 kV line and HYTS – APD – TRTS 500kV line (point [2]).	TRUE	The unexpected operation of protection separating South Australia could lead to cascading failure if repeated while South Australia is importing and has insufficient UFLS.
31/01/2020 13:24	Non-credible	-531	Severe weather caused transmission tower failure and the loss of the MLTS – HGTS 500 kV line and MLTS – MOPS 500 kV line (point [5]).	TRUE	This event could lead to cascading failure if South Australia was importing, and South Australia UFLS is insufficient.
02/03/2020 12:00	Credible	-14	Malfunctioning 500 kV circuit at HYTS led to opening of single line connecting Victoria and South Australia.	FALSE	Credible contingency
12/11/2022 16:39	Non-credible	-208	Severe weather caused transmission tower failure.	FALSE	Location of separation within South Australia out of scope.

4 Analysis approach

This section provides a summary of the assumptions and assessment approach applied. Detailed modelling assumptions are summarised in Appendix A1.

4.1 Assessment approach for different timescales

The Frequency Operating Standard (FOS) provides that for a multiple contingency event resulting in an island within the mainland, reasonable endeavours be taken such that frequency is contained with 47-52 Hz, stabilised to within 49-51 Hz within two minutes, and recovered to within 49.5-50.5 Hz within 10 minutes[16].

To determine the measures required to meet these requirements, this report separates the analysis into two parts:

- **Frequency containment** – studies focused on meeting containment requirements in the *first 60 seconds* following separation. Power system containment risks are identified in Sections 5 and 6, with management measures outlined in Section 7.
- **Frequency stabilisation and recovery** – studies focused on meeting the stabilisation and recovery requirements in the *10 minutes* following a separation event. Power system recovery risks are outlined in Section 8, with management measures outlined in Section 9.

These elements occur on different timescales and therefore are studied with different approaches and have different management measures. For this reason, they have been considered separately to allow independent consideration of the management measures for each. Analysis for each timeframe assumes that the other issue is suitably addressed with the recommended management measures.

4.2 Scenarios and generator dispatch assumptions

ISP scenarios

Studies were conducted based on interconnector flows and generator dispatch outcomes from AEMO's 2022 *Integrated System Plan* (ISP) Plexos market model for every 30-minute interval in the two financial years 2022-23 and 2023-24, prior to the expected commissioning of the Project EnergyConnect (PEC) interconnector. DPV and load growth forecasts were applied from the 2022 ISP *Step Change* scenario[17].

Minimum unit requirements in South Australia

Following commissioning of the four ElectraNet synchronous condensers, there is an ongoing program of work to assess the minimum synchronous unit requirements in South Australia.

[16] For this study, AEMO has applied the Mainland system frequency outcomes for an island (rather than for an interconnected system). The FOS is unclear on which standard should be applied for a multiple contingency event that results in an island. AEMO has applied the less onerous (island) standard in the design of measures in this study, but can adjust this on advice from the Reliability Panel if required.

[17] AEMO 2022, *2022 Integrated System Plan (ISP)*, https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

To ensure the analysis in this report is robust to the possible outcomes of this process, this analysis has been performed with two sensitivities:

- **2 x synchronous generator requirement** – present minimum two synchronous generating unit requirement is sustained in South Australia. A minimum of at least two synchronous generating units is maintained online in South Australia in all periods, noting that many periods will feature more synchronous units online where this is the least-cost dispatch to meet demand.
- **No synchronous generator requirement** – the existing minimum two synchronous generating unit requirement is removed. Dispatch patterns may include periods with no synchronous units online in South Australia, but also features various numbers of synchronous units online in many periods when this is the least-cost dispatch outcome. Synchronous generating units are only dispatched if the South Australian energy price is sufficient to cover their assumed short run marginal costs (SRMC).

The use of these two dispatch sensitivities allows assessment of the risks and proposed management measures in both cases, to ensure they are robust to possible findings about minimum synchronous unit requirements in South Australia. Both forecast scenarios feature many periods with between three and six synchronous generating units online. A dispatch scenario with a minimum of a single synchronous unit requirement has not been studied explicitly in this report, but findings are expected to be robust in such a scenario.

All forecast scenarios are assumed to have the four ElectraNet synchronous condensers available and operating.

The 2022 ISP projections suggest that future scenarios will have an increased likelihood of reduced synchronous generation and inertia levels in South Australia, and increased incidence of import periods into South Australia. With more periods of import, there is a greater proportion of periods where the UFLS scheme is relied on to manage the double-circuit loss of the interconnector.

4.3 Models applied

The following approach has been applied for the analysis:

- **Selected studies were conducted in a root mean square (RMS) model (PSS®E)**, analysing separations at Heywood (point [1] in Figure 6) and Moorabool (point [5]) under a select range of conditions. These studies provided a benchmark for power system frequency outcomes, and were used to identify conditions where relevant control schemes may operate, or where there may be voltage or reactive power issues or other complicating factors that are influential in simulation outcomes.
- **A multi-mass model (MMM) representation** of the South Australian power system was constructed in Matlab/Simulink, with frequency outcomes tuned against the selected RMS model cases. This model was designed and validated to represent the frequency outcomes in South Australia following various non-credible contingency events.

The MMM is a relatively simple model that allows rapid assessment of many trading intervals, and informs an assessment of the percentage of periods at risk given a spectrum of possible dispatch outcomes (necessary for this analysis to probabilistically estimate unserved energy associated with a non-credible contingency event).

The MMM **does not directly include any representation of power system voltages, reactive power, or system strength**. It is only possible to study a relatively small number of cases in detailed models that include these factors. For this reason, only selected case studies have been conducted in the RMS model, and these were used to inform the MMM analysis.

For separations at points [1] to [5] leading to under-frequency, no voltage or stability issues were identified in the selected RMS studies undertaken (summarised at length in Appendix A3), so this approach is considered reasonable. For non-credible separation events at [1] to [5] leading to over-frequency in South Australia, some RMS studies indicated stability issues and complicating factors. For this reason, the MMM outcomes may not reflect real power system outcomes in these cases, and separations leading to over-frequency are considered out of scope, requiring further investigation.

While risks related to voltage, system strength or reactive power management have not been associated with non-credible separation events leading to under-frequency in the studies undertaken to date, it is possible future studies will identify issues not captured in this analysis.

4.3.1 Key assumptions for the multi-mass model (MMM) representation of South Australia

The MMM representation of the South Australian power system applied for these studies includes:

- **Synchronous generator governor models** – aligned with mandatory Primary Frequency Response (PFR) requirements, with frequency control ancillary services (FCAS) maximum registered quantities and trapeziums used as a proxy for likely PFR response.
- **Inverter-based resources** – batteries were assumed to provide FFR, summarised in Section 4.7. A proportion of semi-scheduled wind and solar plant is assumed to have an over-frequency droop response.
- **UFLS** – availability modelled based on projected UFLS load availability in each frequency block in each half-hour, excluding the impacts of dynamic arming of UFLS relays. This includes a delayed UFLS block with an average load of 14 MW that trips following frequency below 49.0 Hz and remaining below 49.5 Hz for more than 30 seconds.

Further details on the modelling assumptions are summarised in Appendix A1, and more information on the RMS and EMT models can be found in Appendix A3.

4.4 South Australia under-frequency load shedding (UFLS) interventions

There are a range of interventions in various stages of completion aiming to improve performance of the South Australian UFLS scheme in periods with high DPV generation. They are incorporated into this analysis as described below.

4.4.1 New UFLS loads

Approximately 300 MW of new loads have been added to the South Australian UFLS scheme between 2020 and 2022. These new loads increase total UFLS load and aid in preventing cascading failure. As many of these loads are considered sensitive, most of these loads have been placed at the bottom of the scheme (47.5 and 47.6 Hz bands), where they will be tripped last. These new loads in the SA UFLS have been included in all the analysis in this report.

4.4.2 Dynamic arming of UFLS relays

Dynamic arming aims to dynamically disarm UFLS circuits (also referred to as “blocking” arming of UFLS circuits) when they are operating in reverse flows (based on local measurements of active power flows on each circuit). If dynamic arming is not implemented, “reverse” operation of the UFLS scheme may exacerbate an under-frequency event, rather than helping to arrest it[18]. In South Australia, implementing dynamic arming requires a substantial program of work to replace and re-configure a large proportion of the UFLS relays in the distribution network.

The Australian Energy Regulator (AER) has approved the SA Power Networks (SAPN) proposal for a cost pass-through for the implementation of dynamic arming[19]. The rollout of these measures is underway, and is expected to continue during 2023 and 2024. Dynamic arming will gradually increase UFLS load availability, which will reduce power system risk, and reduce market costs of the management measures proposed in this report.

At the time the analysis for this report was conducted, there was considerable uncertainty over the timing and amount of UFLS load that would be added to the scheme via dynamic arming rollout in 2022-23 and 2023-24, so the impact of dynamic arming on UFLS load has not been directly included in the analysis in this report. However, the proposed management measures outlined in this report account for available UFLS load in real time. As the dynamic arming rollout progresses, consequent increases in UFLS load will be automatically accounted for without need for re-design. This means the market impact of the proposed management measures may reduce over time compared with what is shown in this report.

4.4.3 Constraints on the Heywood interconnector

There are a number of constraints applied to the Heywood Interconnector which manage risks associated with a non-credible separation.

In 2016, under Regulation 88A[20], the following constraint was implemented on the Heywood Interconnector:

- **Rate of change of frequency (RoCoF) limit** – imports and exports from South Australia limited to maintain instantaneous RoCoF for a non-credible separation at Heywood to less than ±3 hertz per second (Hz/s).

In October 2020[21], the following updates were made, following studies on the ability of UFLS to manage non-credible separations at Heywood:

- **RoCoF limit on imports** – imports into South Australia limited to maintain instantaneous RoCoF for a non-credible separation at Heywood to less than -2 Hz/s. The export limit was unchanged at +3 Hz/s.

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[18] AEMO (May 2021), *South Australian Under Frequency Load Shedding – Dynamic Arming*, https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf?la=en&hash=C82E09BBF2A112ED014F3436A18D836C

[19] AER (1 June 2023) SA Power Networks – Cost pass through – Emergency standards 2021-22, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-pass-throughs/sa-power-networks-cost-pass-through-emergency-standards-2021%E2%80%9322

[20] Regulation 88A

of the *Electricity (General) Regulations 2012* (SA), introduced by the *Electricity (General) (Provision of Limit Advice) Variation Regulations 2016*, No 240 of 2016 https://www.legislation.sa.gov.au/__legislation/lz/v/r/2016/electricity%20(general)%20(provision%20of%20limit%20advice)%20variation%20regulations%202016_240/2016.240.un.pdf.

[21] AEMO (October 2020) Heywood UFLS constraints, https://aemo.com.au/-/media/files/initiatives/der/2020/heywood-ufls-constraints-fact-sheet.pdf?la=en&hash=066F80AE0EE3CF9701A0509818A239BB.

- **Regression limit on imports –** imports into South Australia reduced to levels that can be effectively managed by the expected capability of the UFLS scheme. This regression constraint adjusts dynamically in real time based on UFLS load, DPV generation, power system inertia and FFR.

The cost-effectiveness of these constraints in reducing power system risks (accounting for the impact of increased market costs) has been assessed against a counterfactual case where imports and exports on the Heywood Interconnector are maintained below the instantaneous ±3 Hz/s RoCoF threshold. This counterfactual (without the additional import constraints) is used as the "base case" throughout this report, unless otherwise noted, so that the costs and benefits of these import limits could be assessed.

AEMO does not recommend any adjustment to the instantaneous ±3 Hz/s RoCoF limits (implemented under Regulation 88A), as beyond this threshold there is low confidence that emergency frequency controls schemes will operate properly to arrest a disturbance[22].

4.5 Risks associated with extreme RoCoF

Extreme RoCoF conditions can be experienced in South Australia following a non-credible separation event. Risks associated with extreme RoCoF in South Australia have been analysed as part of this study. A detailed assessment of RoCoF-related risks is outlined in Appendix A2. In summary:

- There is considerable uncertainty over RoCoF withstand capabilities.
- AEMO's assessment suggests that inverter-based generation and distributed generation are likely to be minimally affected by extreme RoCoF in the NEM, with a few exceptions that have specific RoCoF protection settings[23].
- Generally, large synchronous generating units can be anticipated to successfully ride through disturbances up to ±1 Hz/s (with some exceptions), but many may demonstrate a range of issues for disturbances at ±2 Hz/s. There are a range of possible failure mechanisms, affected by a wide range of factors, and many of these are difficult to study and difficult to incorporate into the models typically applied for power system analysis. Based on observations during historical events, international studies, and how often the units operate, AEMO's assessment (summarised in Appendix A2) suggests that:
  - Risks are probably low for most synchronous units in South Australia, but:
  - There is a meaningful risk that the gas turbine units (GTs) at Pelican Point closed-cycle gas turbine (PPCCGT) may trip in response to extreme RoCoF. Given how often PPCCGT operates, and the dispatch levels at which the station typically operates, this could have important consequences in a significant proportion of periods.

[22] AEMO 2022, *AEMO Advice: Reliability Panel Review of Frequency Operating Standard*, Section 3.2, https://www.aemc.gov.au/sites/default/files/2022-12/AEMO%20FOS%20advice%20to%20the%20Reliability%20Panel%20FINAL%20for%20Publishing%20221205.pdf.

[23] Two wind farms in South Australia have existing anti-islanding protection settings that trip the generators if RoCoF exceeds ±1 Hz/s for more than one second. These protection settings have been modelled in all studies in this report.

4.5.1 Assumptions for RoCoF withstand capabilities

AEMO has requested information from the power station operators on the RoCoF ride-through capabilities of PPCCGT, but the exact level at which these units may trip in response to extreme RoCoF remains unknown. For this analysis, AEMO has assumed the following:

- **Base assumption** – if RoCoF exceeds ±2 Hz/s for >100 ms, the gas turbines (GTs) at PPCCGT trip. The PPCCGT steam turbine (ST) is assumed to disconnect 40 seconds after the GTs, due to the loss of steam[24].
- **Sensitivity 1 –** GTs at PPCCGT trip if RoCoF exceeds ±2 Hz/s for >250 ms. The PPCCGT ST disconnects 40 seconds after the GTs, due to the loss of steam.
- **Sensitivity 2** – PPCCGT remains connected and successfully rides through high RoCoF.

The incidence and scale of risks, as well as the proposed risk management options presented in this report, are based on the RoCoF withstand base assumption for PPCCGT outlined above. If further information becomes available about PPCCGT's RoCoF withstand capabilities, these remediation approaches should be reviewed.

4.6 Generation tripping on SA separation

The PSCAD models of Lake Bonney Wind Farm 1-3 (LKB1-3) and Canunda Wind Farm (CNUN), which have been provided to AEMO to represent these generating units in power system studies, show that these plant may trip following a separation between Heywood and Moorabool (points [1] to [5] in Figure 6) if they are generating above certain thresholds. To manage this, these wind farms are constrained to 60 MW and 35 MW respectively during periods where South Australia is at credible risk of separation[25].

A range of assumptions have been applied in this report to represent this behaviour, discussed further in Section 7.6.1.

Iberdrola has requested that LKB1-3 be added to an intertrip scheme, such that the trip of the wind farm will occur in a stable manner. Following this, it is proposed that the 60 MW constraint in place during periods where South Australia is at credible risk of separation could be eased, although other constraints designed to manage the loss of the wind farm's generation will be required. Details of the scheme are still being determined, but are not relevant to this analysis (which focuses on non-credible separation events only).

4.7 Fast Frequency Response (FFR)

High FFR raise levels reduce under-frequency containment risks for South Australia, as raise FFR augments UFLS by providing rapid active power injection following a generation loss.

For these studies, it was assumed that FFR is delivered by Battery Energy Storage Systems (BESS), with a 1.7% droop, a ±0.015 Hz deadband and responding to a disturbance with a 200 ms delay.

[24] As the PPCCGT ST runs on steam from the GTs, the ST typically trips within 40-75 seconds following a trip of the GT (as the ST runs out of steam). The exact time at which the ST trips may vary depending on station operating conditions, the non-credible contingency, and the RoCoF trip mechanism. In 2005, when PPCCGT tripped in the 2005 high RoCoF event, the ST disconnected after the GT within approximately 40 – 75 seconds.

[25] AEMO, *Transfer Limit Advice – System Strength in SA and Victoria*, April 2023, Section 2.2, https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

- **Base assumption** – a total of 150 MW headroom and 120 MW footroom was assumed to be available in total in South Australia in all forecast periods. At least 150 MW raise and 120 MW lower response was available in South Australia from the existing BESS in South Australia across 75% of the year in 2020-21 and 2021-22.
- **Sensitivity** – at the time of modelling, the 250 MW Torrens BESS was considered 'anticipated' and thus was not modelled in the market model dispatch forecast (Section 4.2). A sensitivity was modelled where the Torrens BESS was assumed to provide FFR in a manner similar to existing BESS. Results for this sensitivity are included in Section 7.9.2.

FFR response availability may vary significantly between trading intervals. Sensitivities were considered in the studies to design constraints and other management measures that scale in real time with FFR availability. In particular, interconnector constraints are designed to allow greater import in real time if FFR response capability in South Australia is high in that trading interval. This recognises the possibility of new FFR providers commissioned in South Australia.

All studies assume unlimited energy availability from BESS, as FFR providers are rarely energy limited in the 60-second timescale considered by frequency containment models. Possible limitations are noted where relevant (but not directly represented in the studies).

4.8 Control schemes

There are various control schemes that strongly influence power system outcomes, particularly for separation events in the South-West Victoria network (points [3], [4] or [5] in Figure 6). These include the Emergency APD Potline Tripping scheme (EAPT) and the South-West Victoria Generator Fast Trip scheme (SWV GFT). These are summarised in Section 6.1, including an outline of how they have been represented in the studies in this report.

4.9 Acceptance criteria

4.9.1 Frequency containment

For frequency containment studies (Section 5 and Section 6), simulation outcomes were assessed against the acceptance criteria summarised in Table 9.

Table 9 Acceptance criteria for frequency containment studies

	Frequency nadir in first 60 seconds	Likely outcomes	Assumed likelihood of cascading failure
Fail	Falls below 47.6 Hz	Cascading failure to a black system is considered likely. Setting the threshold at 47.6 Hz allows a buffer of 0.6 Hz over the requirement in the FOS, to account for modelling uncertainty.	100%
Risk	Falls below 48 Hz	These cases are highlighted as severe events with frequency far outside normal ranges, with some risk of cascading failure (for example, due to factors not represented in these models).	50%
Pass	Remains above 48 Hz	For these cases, there is reasonable confidence that the power system will survive the separation.	0%

4.9.2 Frequency stabilisation and recovery

For frequency stabilisation and recovery studies (Section 8), simulation outcomes were assessed against the acceptance criteria summarised in Table 10.

Table 10 Acceptance criteria for frequency stabilisation and recovery studies

	Frequency in first 10 minutes	Likely outcomes	Assumed likelihood of cascading failure
Fail	Not contained within 47-52 Hz, and/or not stabilised within 49-51 Hz within two minutes, and/or not recovered to within 49.5-50.5 Hz within 10 minutes	FOS requirements not met. Possible disconnection of generators potentially leading to cascading failure to black system.	Under-frequency: 30% Over-frequency: 10%
Risk	Stabilised within 49 – 51 Hz within 2 minutes and recovered to within 49.5 – 50.5 Hz within 10 minutes and stable (RoCoF < 0.01 Hz/s)	FOS requirements have been marginally met. Modelling uncertainty presents a risk that frequency will not meet the FOS requirements with the potential for generator disconnection.	Under-frequency: 1% Over-frequency: 0.5%
Pass	Stabilised within 49-51 Hz within two minutes and recovered to within 49.75-50.25 Hz within 10 minutes and stable	For these cases, there is reasonable confidence that the power system will meet the FOS requirements for frequency.	0%

5 Frequency containment – separation at Heywood Interconnector

5.1 Consequences for the power system

This section summarises power system risks identified in frequency containment studies (examining the first 60 seconds following a non-credible separation event) for non-credible separation at the Heywood Interconnector (points [1] or [2] as defined in Figure 6).

5.1.1 Case studies illustrating periods at risk

AEMO's studies indicate several key risk factors, each illustrated in case studies below. The percentage of time associated with each risk factor "type" is summarised in Section 5.1.2.

Risk factor type 1 – low UFLS load

This risk factor is characterised by high levels of DPV generation contributing to low levels of UFLS load. Under these conditions, the loss of the interconnector when there are moderate imports into South Australia could cascade into 'risk' or 'fail' scenarios, which have a high risk of cascading failure.

This risk factor includes a combination of:

- Low load and reverse flows on the UFLS.
- Tripping of DPV generation in response to under-frequency (described in Section 1).
- Moderate import into South Australia.

A case study of such a period is shown in Figure 7, and Table 11 notes key events. The actual scenario outcome with approximately 1.4 gigawatts (GW) of DPV generating is shown in black, compared against an equivalent hypothetical counterfactual case with 0 MW of DPV generating (in grey), to illustrate the effects of DPV.

In the counterfactual scenario without DPV (grey), frequency arrests just below 49 Hz. The trip of UFLS bands between [B] and [C] down to the 48.85 Hz band successfully arrests frequency decline and restores frequency back towards 50 Hz.

Some of the risk periods of this type will be partially addressed by the implementation of dynamic arming of UFLS relays (blocking UFLS relay operation when the feeder is in reverse flows). As noted above (Section 4.4.2), at the time the analysis for this report was conducted, there was considerable uncertainty over the rollout of dynamic arming, so the impact of this measure has not been directly included in the analysis in this report. Mindful of this, management measures have been designed to account for increases in UFLS load, so as the dynamic arming rollout progresses, consequent increases in UFLS load will be automatically accounted for without need for re-design.

Figure 7 Impact of low UFLS on system security: Case study (13:30, spring 2022)

	Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	DPV generation (MW)	Imports at Heywood (MW)	Synchronous generator dispatch
Original scenario	400	251	4,400	1,371	224	None
No DPV, counterfactual	1,771	1,513		0		

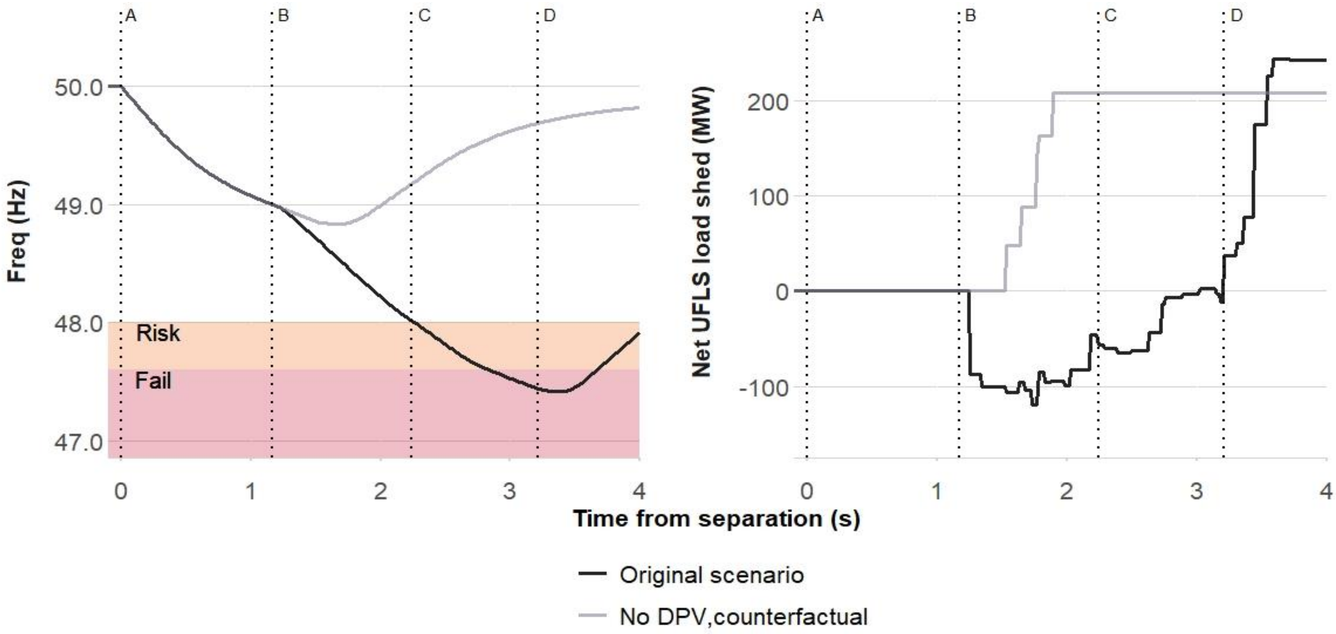


Table 11 Impact of low UFLS on system security: Case study key events (13:30, spring 2022)

	Time from separation	Event	Notes
A	0 seconds (s)	Separation at [1]	• RoCoF following separation is approximately -1 Hz/s (300 ms average). • Rapid active power injection from generators providing FFR assists in arresting the frequency decline.
B	1.17 s	Black scenario: frequency reaches 49 Hz and ~100 MW of DPV disconnects (with a 80 ms delay)	• ~100 MW of DPV disconnects on inverter under-frequency settings (shown as step down in right panel). • This leads to a significant acceleration of frequency decline.
C	2.24 s	Black scenario: reverse UFLS operation	• Frequency decline is further exacerbated by 'reverse' UFLS operation. • UFLS relays disconnect circuits when under-frequency thresholds are reached, but the net UFLS load value 'steps' down due to the trip of UFLS bands in reverse flow, which accelerates frequency decline.
D	3.21 s	Black scenario: trip of positive UFLS load on 47.6 Hz band	• Arrests frequency, but frequency is well below 48 Hz, far outside of typical power system operation ranges. • The loads in this band are considered highly sensitive, and were therefore only added to the bottom UFLS band.

Risk factor type 2 – high import with degraded UFLS or low inertia

These types of risk periods are characterised by:

- High levels of import into South Australia.
- Moderate DPV generation that has reduced UFLS load levels.

- Low to moderate levels of inertia (<6,200 megawatt seconds [MWs]).

In these types of risk periods, although UFLS load is only partially degraded, the very large size of the original contingency event overwhelms the degraded capability of the scheme, leading to cascading failure.

An example of such a period is shown in Figure 8, with black showing the actual case and grey showing a hypothetical counterfactual, with 0 MW of DPV generating and every other system parameter remaining the same, to illustrate the effects of DPV. Key events are noted in Table 12.

This example illustrates a case where the performance of the UFLS is compromised by DPV generation, such that even though moderate levels of UFLS are available, it is not sufficient to manage a large contingency that can still occur when the Heywood Interconnector is importing at high levels into South Australia.

Figure 8 Impact of degraded UFLS when imports are high: Case study (12:00, winter 2023)

	Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	DPV generation (MW)	Imports at Heywood (MW)	Synchronous generator dispatch
Original scenario	856	616	4,400	1,327	506	None
No DPV counterfactual	2,183	1,836		0		

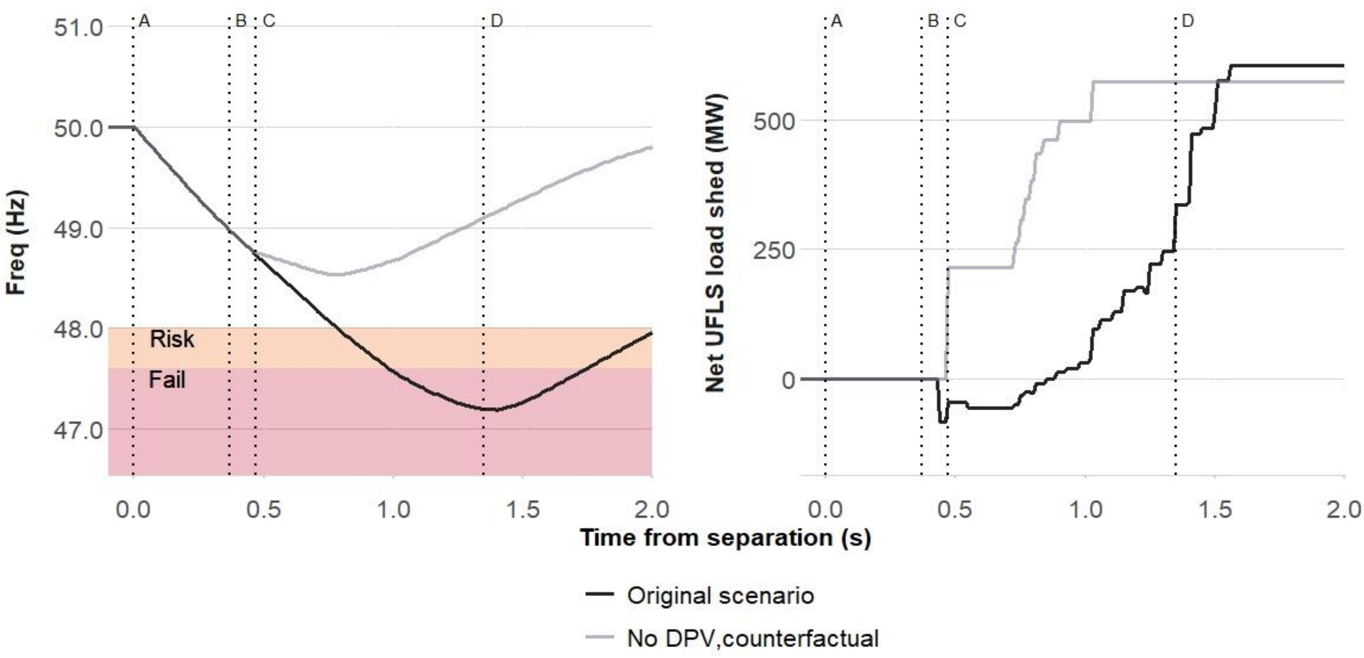


Table 12 Impact of degraded UFLS when imports are high: Case study key events (12:00, winter 2023)

	Time from separation	Event	Notes
A	0s	Separation at [1]	• RoCoF following separation is approximately -2.8 Hz/s (300 ms average). • Rapid active power injection from generators providing FFR assists in arresting the frequency decline.
B	0.37s	Black scenario: frequency reaches 49 Hz and ~100 MW of DPV disconnects on inverter under-frequency settings (shown as step down in right panel)	• Frequency reaches 49 Hz and DPV disconnects (following an 80ms delay). • This leads to a significant acceleration of frequency decline.

	Time from separation	Event	Notes
C	0.47s	UFLS load on RoCoF relays trips[A]	• Grey scenario: the trip of ~215 MW of UFLS load reduces RoCoF to below -2 Hz/s and helps arrest frequency decline. • Black scenario: the high DPV generation has reduced load on RoCoF relays to ~25 MW, and the trip of UFLS load on RoCoF relays is less effective, with RoCoF remaining in excess of -2 Hz/s and frequency continuing to decline.
D	1.35s	Black scenario: trip of positive UFLS load on 47.6 Hz and 47.5 Hz bands	• Arrests frequency, but frequency is close to 47 Hz, far outside typical power system operation ranges ("fail" scenario). • The loads in this band are considered highly sensitive, and were therefore only added to the bottom UFLS band.

A. Approximately 15% of the load on the 47.8 Hz to 49 Hz trip frequency bands in the South Australian UFLS scheme sits behind relays that trigger when RoCoF exceeds 1.5 Hz/s over 100 ms. During low DPV periods, load on RoCoF relays is typically around 200-250 MW. These are designed to trip rapidly following a high RoCoF event to aid in arresting severe frequency disturbances.

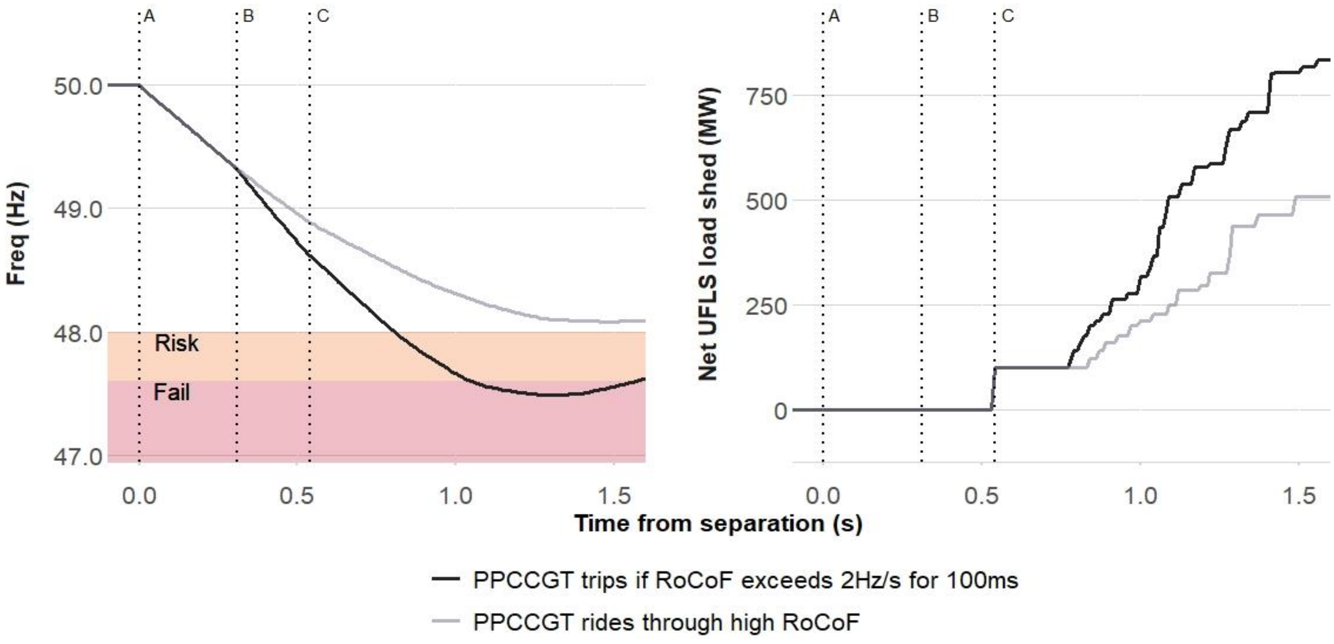
Risk Factor Type 3 – extreme RoCoF leading to synchronous unit trip

The third category of risk period is characterised by extreme RoCoF which could lead to trip of a synchronous generating unit. These types of risk periods typically arise when RoCoF-vulnerable synchronous units are online and imports into South Australia are high.

A case study is shown in Figure 9, with key events noted in Table 13. For this analysis, it has been assumed that PPCCGT could trip if RoCoF exceeds 2 Hz/s for more than 100 ms[26], noting actual RoCoF withstand capabilities are unknown.

Figure 9 Impact of synchronous unit RoCoF ride-through capability: Case study (05:00, spring 2022)

Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	DPV generation (MW)	Imports at Heywood (MW)	Synchronous generator dispatch
1,218	1,019	~7,500	0	650	PPCCGT ST + 1xGT: 217 MW



[26] Modelling assumptions are outlined in Section 4.5.

Table 13 Impact of synchronous unit RoCoF ride-through capability: Case study key events (05:00, spring 2022)

	Time from separation	Event	Notes
A	0 s	Separation at [1]	• RoCoF following separation exceeds -2 Hz/s (300 ms average).
B	0.31 s	Black scenario: PPCCGT trips	• RoCoF accelerates to -2.9 Hz/s (300 ms average) due to loss of GT's generation and inertia[A].
C	0.54 s	UFLS load on RoCoF relays trips[B]	• Grey scenario: acts to slow RoCoF, sufficient to achieve a "pass" scenario if PPCCGT remains online. • Black scenario: acts to slow RoCoF, but does not sufficiently arrest frequency if PPCCGT has tripped. Frequency falls to 47.5 Hz (a "fail" scenario).

A. The PPCCGT ST is assumed to trip 40 seconds later as it runs out of steam from the PPCCGT GTs.
B. Approximately 15% of the load on the 47.8 Hz to 49 Hz trip frequency bands in the South Australian UFLS scheme sits behind relays that trigger when RoCoF exceeds 1.5 Hz/s over 100 ms. During low DPV periods, load on RoCoF relays is typically around 200-250 MW. These are designed to trip rapidly following a high RoCoF event to aid in arresting severe frequency disturbances.

For a separation at Heywood ([1] or [2]), these risks are somewhat mitigated by the RoCoF constraints that limit imports into South Australia[27]. For separations in South-West Victoria (separations at [3], [4] or [5]) risks related to extreme RoCoF leading to synchronous unit trip can occur more often, since generation and load in the South-West Victoria area can lead to more extreme RoCoF in South Australia. This is discussed further in Section 6.2.1.

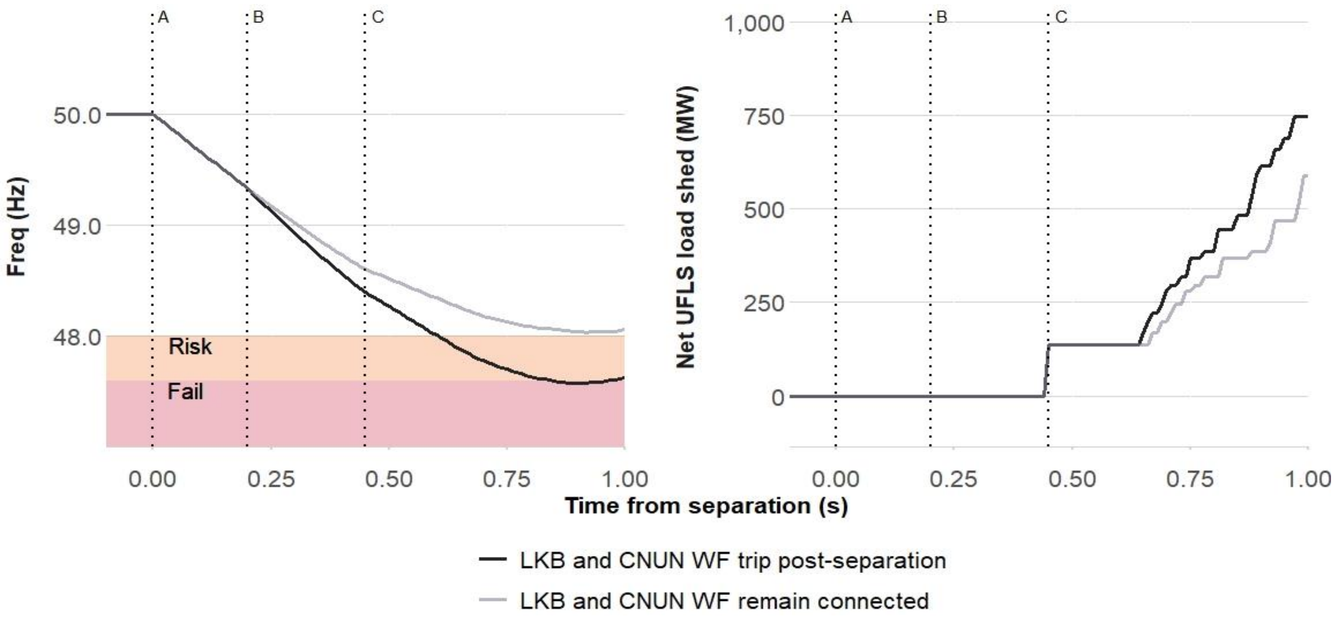
Risk factor type 4 – generation trip exacerbates contingency

The next category of risk period is associated with a possible trip of LKB1-3 and CNUN wind farms following separation (as discussed in Section 4.6). These risks typically arise when there are high levels of generation at LKB1-3 and CNUN WF, high imports into South Australia, and low inertia in the region. A case study is shown in Figure 10, with key events in Table 14.

[27] A 3 Hz/s constraint on imports into South Australia does not protect against all Type 3 risks, as some synchronous plant may be unable to ride through RoCoF in excess of 2 Hz/s.

Figure 10 Impact of generation trip that exacerbates contingency: Case study (spring 2023, 01:30)

Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	HIC import (MW)	LKB + CNUN generation (MW)	Synchronous generator dispatch
1,576	1,276	~4,500	600	152	4 x BIPS[A]: 67 MW



A. Barker Inlet Power Station (BIPS)

Table 14 Impact of generation trip that exacerbates contingency: Case study key events (spring 2023, 01:30)

	Time from separation	Event	Notes
A	0 s	Separation at [1]	• Frequency declines.
B	0.2 s	Black scenario: LKB1-3 and CNUN WF trip	• Wind farms assumed to trip 200 ms following separation.
C	0.45 s	UFLS load on RoCoF relays trips[A]	• Grey scenario: acts to slow RoCoF, sufficient to achieve a "pass" scenario if LKB+CNUN remain online. • Black scenario: acts to slow RoCoF, but does not sufficiently arrest frequency if LKB+CNUN have tripped. Frequency falls to 47.58 Hz (a "fail" scenario).

A. Approximately 15% of the load on the 47.8 Hz to 49 Hz trip frequency bands in the South Australian UFLS scheme sits behind relays that trigger when RoCoF exceeds 1.5 Hz/s over 100 ms. During low DPV periods, load on RoCoF relays is typically around 200-250 MW. These are designed to trip rapidly following a high RoCoF event to aid in arresting severe frequency disturbances.

In the counterfactual case (shown in grey in Figure 10), the LKB1-3 and CNUN wind farms remain connected and frequency remains above 48 Hz (a "pass" case). When the wind farms trip (shown in the black case), frequency falls below 47.6 Hz (a "fail" case). This demonstrates that the trip of these wind farms can impact frequency outcomes.

Risk factor type 5 – interconnector flows exceeding thresholds

Interconnector flows can occur above imposed constraints, due to factors such as:

- Interconnector drift within trading intervals (due to movements in load or generator levels), or

- Timestep differences in constraint inputs – if a meaningful change occurs in constraint inputs shortly before the start of a trading interval, the constraint will be set based on the previously measured value, as the constraint lags behind real-time values.

There is some risk UFLS efficacy reduces at high levels of RoCoF. If RoCoF post-separation exceeds 3 Hz/s, there is a risk that UFLS action will occur not occur quickly enough to arrest a frequency decline[28]. The impact of high RoCoF on UFLS has been partially included in this analysis. The UFLS relay time delays have been modelled as accurately as possible based on SAPN advice and will therefore to some degree represent UFLS limitations at extreme RoCoF levels.

Timestep issues are partially included in the MMM studies, to the extent that the input dispatch patterns simulated in Plexos partially reflect real generator commitment and decommitment patterns (the accuracy of unit commitment in the Plexos dispatch has not been examined in detail for this report). Interconnector drift within trading intervals has not been included in this analysis.

These are real effects that exacerbate risk for South Australian separation events, but they are not the main focus of this report. Some residual risk associated with these effects will remain, even following application of the proposed management measures.

Risk factor type 6 – over-frequency

In up to 26% of trading intervals in the forecast period 2022-23 to 2023-24, a separation at Heywood (point [1] or [2]) would lead to over-frequency in South Australia (typically when South Australia is exporting energy to Victoria).

RMS studies suggest a possibility that a separation at Heywood leading to over-frequency may lead to instabilities on the Queensland – New South Wales Interconnector (QNI) and other complicating factors (summarised in Appendix A3), so these conditions require further analysis and are excluded from this analysis. This report focuses on management measures for under-frequency conditions in South Australia only.

The South Australian over-frequency generation shedding (OFGS) scheme has recently undergone review and changes are in the process of implementation.

5.1.2 Percentage of time at risk

The distribution of outcomes for the 2022-23 and 2023-24 forecast years for a “clean” double-circuit separation at the Heywood Interconnector ([1] or [2]) is shown in Figure 11. Each dot represents an outcome of the MMM, with blue, orange and red dots representing pass, risk and fail cases respectively (applying the acceptance criteria summarised in Section 4.9). Total UFLS load in South Australia is shown on the horizontal axis and the contingency size on separation is shown in the vertical axis[29]. The approximate zones relating to the various types of risk factors are indicated, with the definitions for each summarised in Table 15 for reference.

[28] AEMO 2022, *AEMO Advice: Reliability Panel Review of Frequency Operating Standard*, Section 3.2, https://www.aemc.gov.au/sites/default/files/2022-12/AEMO%20FOS%20advice%20to%20the%20Reliability%20Panel%20FINAL%20for%20Publishing%20221205.pdf.

[29] These studies include the new loads added to the SA UFLS, but do not include dynamic arming of UFLS relays, and do not include the Heywood Interconnector constraints that limit Heywood imports when UFLS load is low (see Section **Error! Reference source not found.** f or further details). Contingency size is assumed to include the imports on the Heywood Interconnector, plus the generation of units that trip when South Australia separates.

Figure 11 Distribution of frequency containment outcomes in 2022-23 and 2023-24 following a separation at Heywood (points [1] or [2])

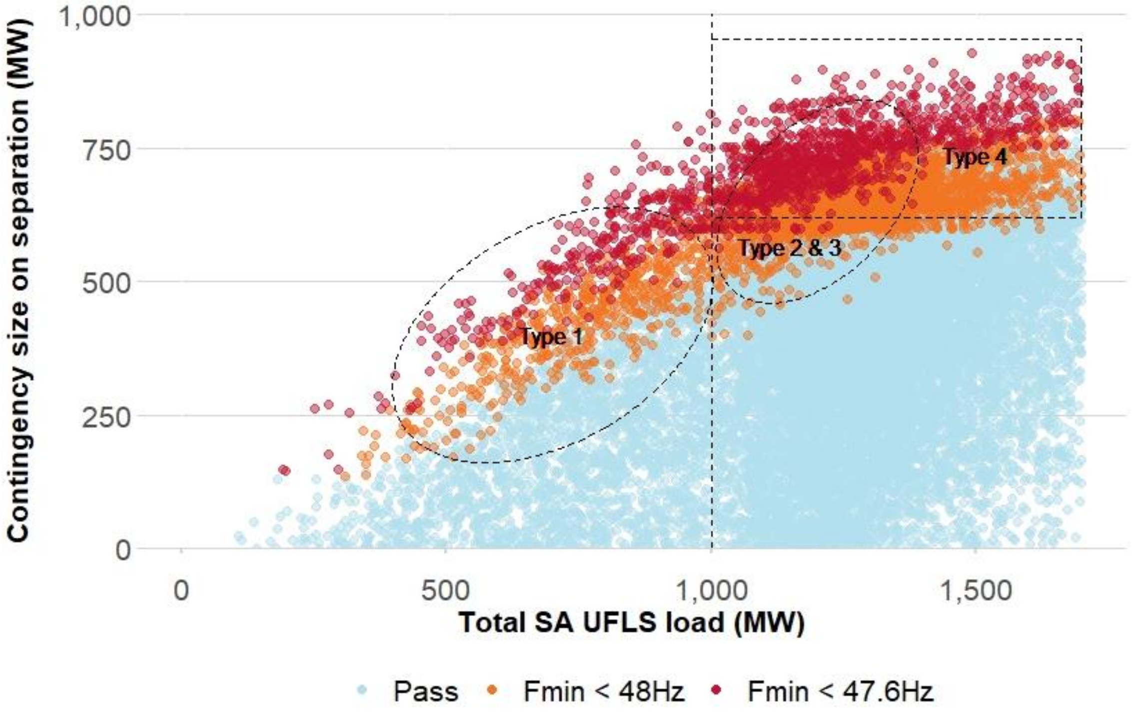


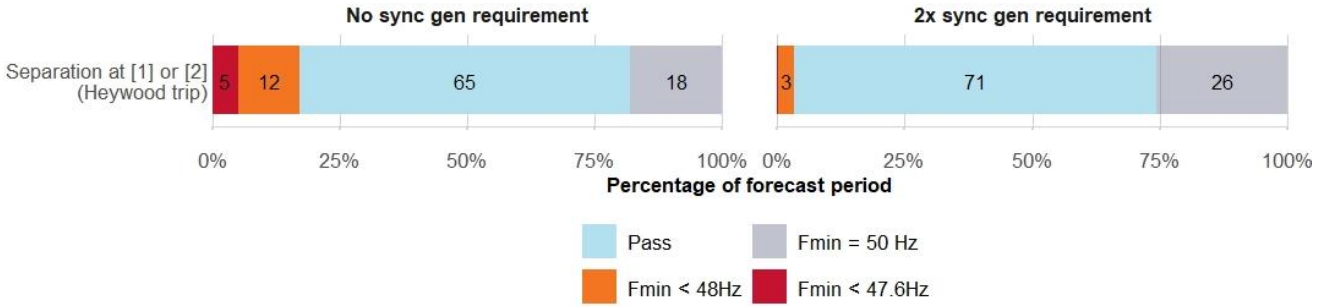
Table 15 shows the approximate percentage of time associated with each type of risk factor, and the amalgamated total percentage of time at risk (combining all factors without double counting where multiple risk factors arise in the same period) is summarised in Figure 12. These percentages are based on a counterfactual scenario where the existing limits on Heywood imports into South Australia when UFLS is insufficient are not implemented.

Table 15 Percentage of 2022-23 to 2023-24 at risk or fail in each category (separation at [1] or [2]) A

Risk factor	Failure mechanism	% of 2022-23 and 2023-24 in this risk category (risk or fail)	
		2 x sync gen requirement	No sync gen requirement
Type 1	Low UFLS load	1%	3%
Type 2	High import with degraded UFLS or low inertia	1%	11%
Type 3	Extreme RoCoF leading to synchronous unit trip (Modelling assumes PPCCGT trips if RoCoF exceeds 2 Hz/s for ≥100 ms)	0.5%	5%
Type 4	Generation trip exacerbates contingency (Modelling assumes LKB + CNUN WFs trip 200 ms after separation)	2.5%	10%
Type 5	Interconnector drift or timestep issues leading to RoCoF > 3 Hz/s	Not quantified in these studies	
Type 6	Over-frequency (up to 26% of trading intervals in 2022-23 to 2023-24)	Not quantified in these studies (out of scope)	

Multiple risk factors may be present in a single period.

Figure 12 Percentage of periods at risk in 2022-23 and 2023-24 following a separation at [1] or [2]



Observations are as follows:

- In the scenario with no minimum requirements for synchronous generators to remain online, up to 17% of periods are at risk, across a mix of Type 1 to Type 4 risk factors.
- In the scenario with the 2 x synchronous generator requirement, approximately 3% of periods are at risk.

This indicates that the projected incidence of risk is strongly dependent on generator dispatch, which is difficult to predict accurately (even if future minimum unit requirements were known at this time). Management measures (outlined in Section 7) have therefore been designed to show a positive cost/benefit in both scenarios, and are designed to adapt to real-time operational conditions and generator dispatch. This means intervention only occurs when risk conditions are present, and market costs are only incurred when risk is present, based on actual real-time generator dispatch.

In the no synchronous generator requirement scenario, 8% of periods in 2022-23 and 2023-24 show risk and fail outcomes when there is one or more synchronous units online. This indicates that risk/fail scenarios are not solely associated with the condition of no synchronous generators being online, and can also occur with synchronous units online. The differences in the percentage risk periods shown in Figure 12 are due to a more subtle outcome of the Plexos modelling approach, which may or may not reflect real outcomes.

If the projected dispatch patterns associated with maintaining the present two unit minimum requirement eventuate, the proposed management measures should bind very rarely because very minimal intervention is required. Due to considerable uncertainty in future dispatch patterns, AEMO suggests that the recommended interventions (outlined in Section 7) should be implemented regardless of minimum synchronous unit requirements, so that these constraints are managing possible periods of risk that might arise across a range of possible dispatch outcomes.

Modelling limitations

These studies are conducted in a MMM which does not explicitly represent power system voltages, reactive power, or system strength. The above analysis only examines frequency outcomes based on a simple swing equation approach, and is designed primarily to examine UFLS adequacy in low demand conditions, although some selected PSS®E studies have been conducted for benchmarking purposes, and to confirm there are no other obvious sources of system collapse or failure (as summarised in Appendix A3).

This analysis does not in any way examine other power system requirements (such as system strength or grid forming), and makes no assessment regarding the potential to survive a double-circuit separation event with no synchronous generating units online.

5.2 Unserved energy estimates

The amount of unserved energy (USE) and costs associated with USE risks are summarised in Table 16. These values were estimated based on the estimated likelihood of a black system event, and the range of possible USE associated with each black system event (with full approach and assumptions summarised in Appendix A4). The range indicated is associated with the estimated range of probability of a black system event occurring, and the range of USE that could eventuate if a black system event occurs.

Table 16 USE estimates – separation at Heywood Interconnector ([1] or [2])

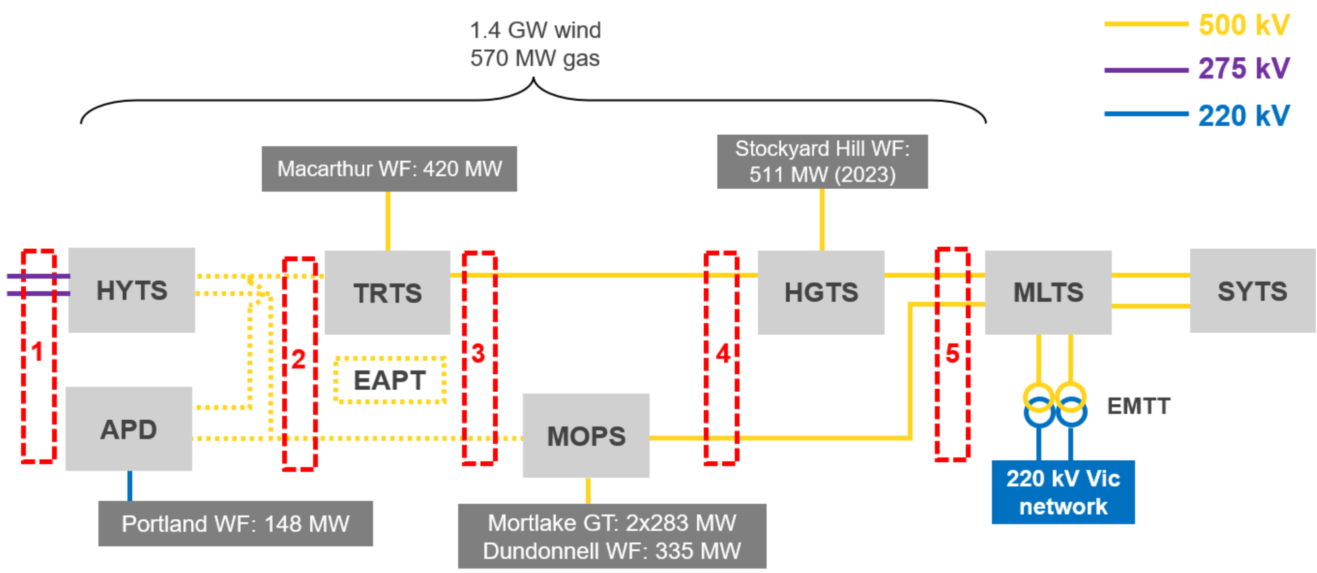
	USE (MWh/year)	Annual cost ($ million/year)	
		Standard VCR	2 x VCR
No minimum synchronous unit requirement	167-741	$8 - $36	$16 - $73
Minimum 2 synchronous unit requirement	26-116	$1 - $6	$3 - $11

6 Frequency containment – separation in the South-West Victorian 500 kV network

There are multiple possible places where South Australia can separate from the rest of the NEM, as discussed in Section 2. This section examines the outcomes for the power system in the event of a separation in the 500 kV South-West Victoria (SWV) network, east of Heywood (locations [3], [4] or [5] in Figure 13). A separation at [2] produces similar frequency outcomes for South Australia to a separation at [1].

For ease of reference in reading this section, Figure 6 outlining the separation locations studied has been duplicated below as Figure 13. Separations at locations [1], [2] and [5] in Figure 13 have occurred in the last five years.

Figure 13 South Australia separation points studied in this analysis, numbered [1] to [5]



[1]: Heywood - South East (HYTS - SESS) 275 kilovolt (kV) lines.
[2]: Heywood – Alcoa Portland - Mortlake (HYTS - APD - MOPS) 500 kV line and Heywood - APD - Tarrone (HYTS - APD - TRTS) 500 kV line.
[3]: Heywood - APD - Mortlake (HYTS - APD - MOPS) 500 kV line and Tarrone - Haunted Gully (TRTS - HGTS) 500 kV line.
[4]: Tarrone - Haunted Gully (TRTS - HGTS) 500kV line and Mortlake - Moorabool (MOPS - MLTS) 500 kV line.
[5]: Moorabool - Haunted Gully (MLTS - HGTS) 500 kV line and Moorabool - Mortlake (MLTS -MOPS) 500 kV line.

WF: Wind farm
GT: Gas turbine

6.1 Influential control schemes

A number of important control schemes influence power system outcomes following a separation in the 500 kV South-West Victoria network. These control schemes are summarised below, with details on how they were represented in the MMM.

6.1.1 Emergency APD Potline Tripping (EAPT) Control Scheme

The EAPT scheme is designed to secure the system against separation of the 500 kV network between Moorabool (MLTS) and Heywood (HYTS) terminal stations and prevent the Alcoa Portland Smelter (APD) load in Victoria from remaining connected to an islanded South Australia system. The scheme acts to disconnect HYTS from the South-West Victoria 500 kV network[30], and the lines affected are shown dotted in Figure 13.

By disconnecting APD load from the South Australian island during an extreme under-frequency event, the EAPT scheme aims to slow the frequency decline (reduce RoCoF) in the South Australian island and increase the probability that the South Australian UFLS will adequately arrest the separation event. The EAPT has a meaningful impact on system frequency in South Australia.

A proposed upgrade to the EAPT scheme is in the advanced stages of implementation. In this upgrade, EAPT Mode 1 and Mode 2 are relevant to frequency outcomes following separations in the South-West Victoria network:

- **EAPT Mode 1** – if both topological and performance criteria are met, EAPT activates and separates South Australia at the 500 kV HYTS circuits.
  - **Topological criteria** – met if circuit breakers are open at various possible separation points in the South-West Victorian network.[31]
  - **Performance criteria** – met if frequency *or* voltage at specific locations in the South Australian network fall below these thresholds[32]:
    - Frequency performance criteria for EAPT operation – frequency on either SESS 275 kV line below 49.7 Hz.
    - Voltage performance criteria for EAPT operation – voltage on both HYTS 500 kV busbars below 80% of nominal for greater than 400 ms, indicating a severe voltage depression.
- **EAPT Mode 2** – if topological criteria are met (circuit breakers are detected to be open), EAPT activates to separate at the 500 kV HYTS circuits.

The EAPT scheme is designed to operate in Mode 1 normally and would be switched to Mode 2 only when separation at a location along the HYTS-MLTS 500 kV corridor becomes a credible event (for example, during prior outages of one of the 500 kV lines along the HYTS-MLTS corridor in South-West Victoria).

EAPT Mode 1 and 2 have been modelled in the MMM as closely as possible.

EAPT representation in the MMM

EAPT Mode 2 has been modelled directly in the MMM, as the model captures topological criteria directly. In the MMM, EAPT Mode 2 is assumed to operate 190 ms following the initial separation[33].

[30] AEMO, *Final Report – Queensland and South Australia system separation on 25 August 2018*, Section 3.4, January 2019, 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.

[31] AEMO, *Victorian Annual Planning Report*, Section 4, October 2021, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2021/2021-victorian-annual-planning-report.pdf?la=en.

[32] AEMO, *Final Report – Queensland and South Australia system separation on 25 August 2018*, Section 3.4, January 2019, 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.

[33] This consists of 20 ms for line protection relays to communicate fault to breakers, and 170 ms for breakers to open at Heywood.

The MMM EAPT Mode 1 model was developed and benchmarked against RMS model case studies. The MMM does not directly represent power system voltages, and benchmarking shows that it does not accurately reflect short duration frequency transients which may meet the EAPT Mode 1 performance criteria. Proxies were hence developed so the MMM could capture the range of system conditions that would activate EAPT Mode 1.

The MMM EAPT Mode 1 representation includes:

- **Topological performance criteria** – directly modelled in the MMM.
- **Frequency performance criteria**:
  - For milder separations (RoCoF below -2 Hz/s), EAPT Mode 1 frequency criteria can be modelled directly in the MMM. MMM studies found that under these scenarios, EAPT Mode 1 total operation time is typically around 300 ms to 500 ms.
  - For separations with higher RoCoFs, RMS model benchmark studies showed that EAPT Mode 1 activates rapidly if frequency transients are sufficient to trigger frequency criteria. These benchmark cases had high RoCoFs (exceeding -2 Hz/s, 300 ms average[34]), and showed EAPT Mode 1 operating 190-210 ms after the separation ('rapid' EAPT Mode 1 activation). A MMM RoCoF proxy was hence developed to activate EAPT Mode 1 within 190-210 ms when RoCoF exceeded -2 Hz/s (100ms average[35]).
- **Voltage performance criteria** – RMS model benchmark studies did not show EAPT activating on voltage criteria in under-frequency events.

Following the implementation of these proxies, alongside direct frequency measurements from the MMM, good frequency matching was found across RMS model cases and the MMM. The RMS model studies used to develop these assumptions are detailed in Appendix A3.4.3.

6.1.2 South-West Victoria Generator Fast Trip (SWV GFT) scheme

Following a separation at points [4] or [5], the South-West Victoria Generator Fast Trip (SWV GFT) scheme activates on topological criteria (detection of circuit breaker opening) to trip Dundonnell (DD) and Stockyard Hill (SH) wind farms 170 ms after the event.

The GFT schemes are designed to prevent voltage collapse or instability due to very low system strength in the 500 kV South-West Victoria network post-separation. At present, SWV GFT activation can lead to loss of up to 850 MW generation for separation at [5] and 335 MW generation for separation at [4].

As such, this scheme has an important influence on South Australian frequency following a separation and has been modelled directly in all simulations.

[34] In these PSS®E cases, EAPT activated in approximately 200 ms, faster than the 300 ms typical RoCoF averaging window used in PSS®E. Because of frequency transients modelled in PSS®E, RoCoF averaging windows shorter than 300 ms do not typically produce meaningful results in this case. The 300 ms average is hence calculated on a PSS®E case where EAPT was not modelled.

[35] RoCoF averaged over 300 ms is typically used in this report and the 2022 PSFRR. However, 'rapid' Mode 1 EAPT operation occurs within 190 ms and thus a shorter averaging window is required to determine if rapid EAPT Mode 1 operation will occur. Because the MMM does not capture frequency transients, average RoCoFs over 100 ms and 300 ms are very similar in the MMM.

6.1.3 APD voltage trip

A fault at [5] (on the MLTS-HGTS or MLTS-MOPS lines) leading to a voltage disturbance and the subsequent loss of two APD potlines is reclassified as a credible contingency at present[36]. This reclassification is managed via constraints designed to manage both over-frequency and network loading risks if APD were to trip following the loss of the lines. However, the likelihood of APD trip on a voltage disturbance is challenging to quantify, and may depend on the nature of the fault that occurs.

In an over-frequency event, a possible APD trip may exacerbate over-frequency risks. However, in an underfrequency event, APD trip would assist in arresting frequency decline. This analysis focuses on the separation of South Australia at points [1] to [5] leading to underfrequency. Given the uncertainty around a possible APD trip, the studies in this report assume that APD remains connected, which represents the plausible worst case scenario. If APD trips, this will likely improve frequency outcomes in under-frequency scenarios, compared with the modelled outcomes in this report.

6.2 Consequences for the power system

6.2.1 Case studies illustrating periods at risk

The MMM was used to study power system outcomes for non-credible separation events occurring at [3], [4] or [5] (shown in Figure 13). Selected case studies are outlined below to illustrate the various types of risks identified. Some failure mechanisms are similar to those identified for separations at [1] or [2], but with additional complicating factors and interactions with the various control schemes outlined above, and with different incidence of risks (summarised in Section 6.2.2).

Risk factor type 1 – low UFLS load

Risks associated with low UFLS load (Type 1) were found to be effectively managed by the mitigation measures proposed to manage separation events at [1] or [2], discussed further in Section 5.1.1 and Section 7. The modelling for separation events at [3], [4] or [5] does not indicate any different Type 1 risks that need further management measures.

Risk factor type 2 – high import with degraded UFLS or low inertia

As for Type 1 risks, risks associated with high import periods and degraded UFLS (Type 2 risks) were found to be effectively managed by the mitigation measures proposed to manage separation events at [1] or [2], discussed further in Section 5.1.1 and Section 7. The modelling for separation events at [3], [4] or [5] does not indicate any different Type 2 risks that need further management measures.

Risk factor type 3 – extreme RoCoF leading to synchronous unit trip

Depending on the generation and load in South-West Victoria, a separation in South-West Victoria can lead to extreme RoCoF levels in South Australia (exceeding 3 Hz/s). This means elements in the South Australian power

[36] Chapter 5.3, AEMO, *Power System Frequency Risk Review – Final report*, July 2022, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en.

system (such as generating units) can be exposed to extreme RoCoF following a separation at locations [3], [4] or [5], which could lead to synchronous generator tripping which then exacerbates the under-frequency event.

An example case study is shown in Figure 14, and key events noted in Table 17. As summarised in Section 4.5, for this modelling assessment it has been assumed that PPCCGT could trip if RoCoF exceeds ±2 Hz/s for 100 ms (with outcomes shown in the black line in Figure 14). The grey case in Figure 14 shows an additional sensitivity assuming improved ride-through capabilities up to ±2 Hz/s for 250 ms.

Figure 14 Impact of synchronous unit RoCoF withstand capability: Case study (04:00, summer 2022)

Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	Imports at Heywood [1] (MW)	Generation on South-West Victoria GFT (MW)	Generation at LKB + CNUN (MW)	Imports at Moorabool [5] (MW)	Synchronous generator dispatch
1,428	1,131	~9,000	650	171	61	802	PPCCGT 2xGT + ST: 459 MW 2x BIPS: 32 MW

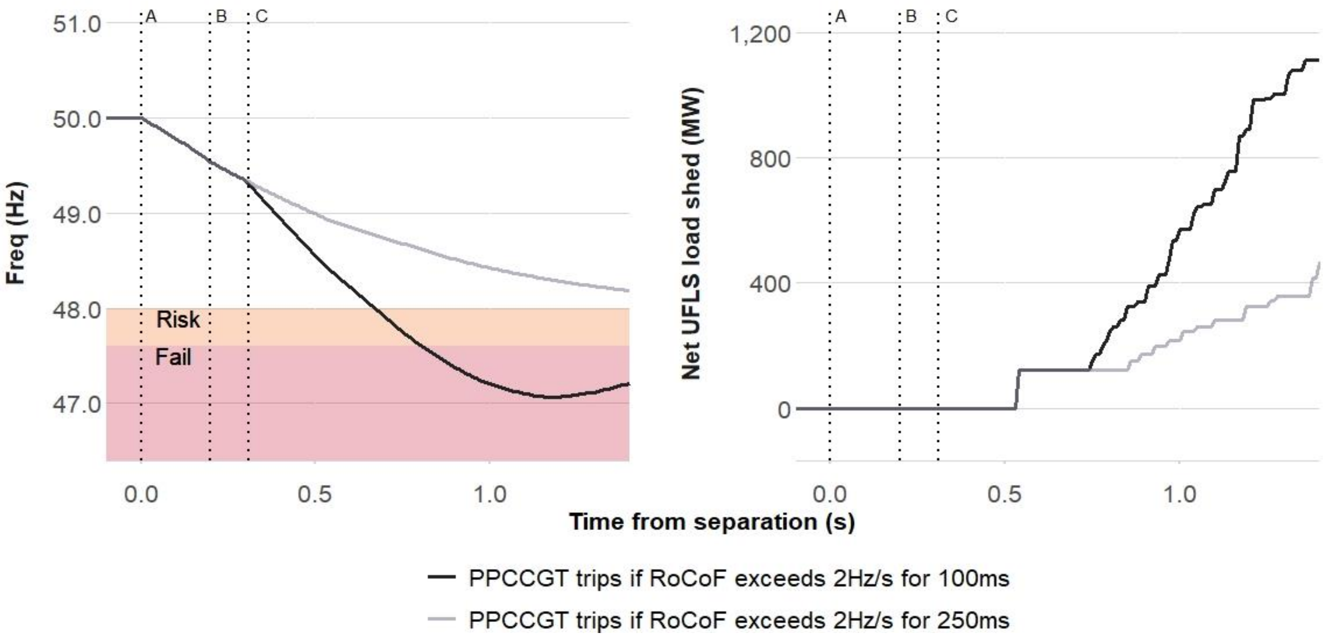


Table 17 Impact of synchronous unit RoCoF withstand capability: Case study key events (04:00, summer 2022)

	Time from separation	Event	Notes
A	0 s	Separation at Moorabool ([5])	RoCoF in the island exceeds -2 Hz/s (100 ms average[A]).
B	0.17 s	South-West Victoria GFT trips (171 MW)	Increases RoCoF in the island to levels exceeding -2.5 Hz/s for a very brief period (30 ms).
	0.2 s	LKB1-3 + CNUN trip (61 MW)	Low generation levels at LKB+CNUN in this case mean this has limited impact on South Australian frequency.
		EAPT activates	Separates South Australia at the 500 kV HYTS circuit breakers, reduces RoCoF to below -2 Hz/s (100 ms average[B]).
C	0.31 s	Black: PPCCGT trips[C]	Frequency accelerates and falls below 47Hz ("fail" outcome).
		Grey: PPCCGT rides through	Frequency remains above 48 Hz ("pass" outcome).

A. RoCoF measurement over a 100 ms window is applied in this context because EAPT operates within 200 ms to reduce RoCoF.
B. RoCoF measurement over a 300 ms window is not relevant in this context because PPCCGT may trip within 100 ms of EAPT operation and accelerate RoCoF.
C. The PPCCGT ST is assumed to trip 40 seconds later as it runs out of steam from the PPCCGT GTs.

The significant difference between the grey and black scenarios is related to the large capacity and high inertia of PPCCGT, so a trip significantly exacerbates the under-frequency condition. This demonstrates that PPCCGT's RoCoF ride-through capabilities impact frequency outcomes.

In this case study, the difference between the two scenarios is dictated by whether PPCCGT can ride through extreme RoCoF (exceeding 2 Hz/s) for the ~200 ms it takes for EAPT to operate and slow RoCoF. The unit's actual RoCoF withstand capability is unknown.

Risk factor type 4 – generation trip exacerbates contingency

Post-separation, the action of the SWV GFT to trip DD and SH WF (discussed in Sections 6.1.2 and 7.4.2), alongside the trip of LKB1-3 and CNUN WF (assumptions outlined in Section 4.6), could exacerbate under-frequency risks in South Australia in some trading intervals. This is illustrated in a case study in Figure 15, with key events noted in Table 18.

As shown in the grey scenario, if LKB and CNUN WF (or WF on the SWV GFT) remain connected, RoCoF remains below -2Hz/s, and the GTs at PPCCGT remain connected. As a result, frequency remains well above 48 Hz. This illustrates that in some scenarios, wind farm trip can exacerbate RoCoF post-separation, increasing the risk of synchronous generator tripping and increasing the risk of failure scenarios.

In some cases, the trip of LKB1-3, CNUN, DD and SH WFs (which have a combined generation capacity of almost 1,200 MW) at high levels of generation can mean an initial over-frequency event becomes an under-frequency event. These cases occur in approximately 1.5% of 2022-23 to 2023-24, and are considered in-scope under-frequency events for the purpose of these studies.

Figure 15 Impact of generation trip that exacerbates contingency: Case study (winter 2023, 06:00)

Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	DPV generation (MW)	Imports at Heywood [1] (MW)	Imports at Moorabool (MW)	Generation on SWV GFT	Generation at LKB + CNUN	Synchronous generator dispatch
1,468	1,217	~9,000	0	439	227	403	153	PPCCGT ST + 2xGT: 393 MW

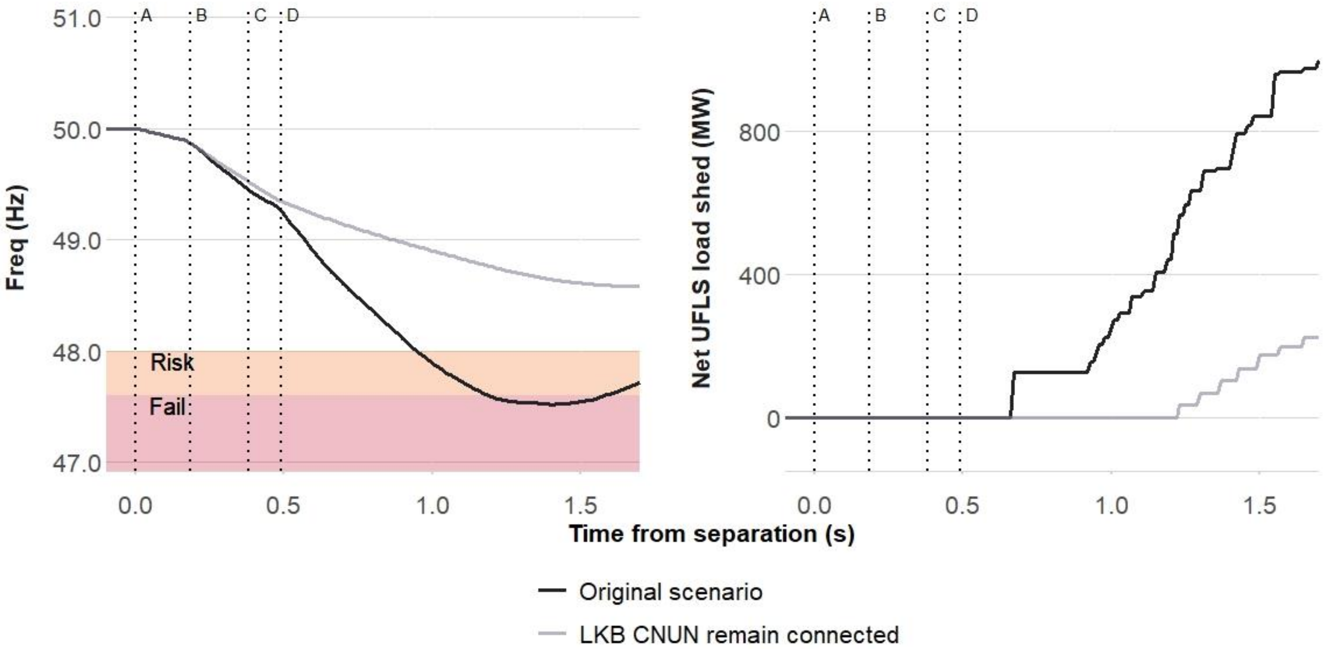


Table 18 Impact of generation trip that exacerbates contingency: Case study key events (winter 2023, 06:00)

	Time from separation	Event	Notes
A	0 s	Separation at Moorabool ([5])	RoCoF is -0.6 Hz/s (100ms average[A]).
B	0.17 s	SWV GFT trips (403 MW)	RoCoF accelerates to -1.8 Hz/s.
	0.2 s	Black: LKB1-3+CNUN trip (153 MW)	RoCoF accelerates to -2.2 Hz/s (100 ms average).
		Grey: LKB1-3+CNUN remain connected	RoCoF remains at -1.8 Hz/s (100 ms average).
C	0.38 s	Black: EAPT activates on frequency transient (RoCoF proxy)	Separates South Australia at [1], reduces RoCoF to -1.6 Hz/s (100 ms average).
D	0.49 s	Black: PPCCGT GTs trip[B]	• Although EAPT has activated and slowed RoCoF, PPCCGT was already exposed to RoCoF >2 Hz/s for 100 ms. The PPCCGT GTs trip, leading to significant loss of generation and inertia. • Frequency accelerates and falls to 47.5 Hz ("fail" outcome).
		Grey: PPCCGT GTs ride through, EAPT activates on frequency criteria	• Power system frequency has remained below the assumed ride-through threshold for PPCCGT (>2 Hz/s for 100 ms). Frequency remains above 48 Hz ("pass" outcome). • EAPT activates as freq < 49.7 Hz for more than 100 ms, reducing RoCoF to -1 Hz/s (100 ms average).

A. A typical 300 ms RoCoF averaging window does not produce relevant results as the SWV GFT and EAPT can activate within approximately 200 ms.
B. The PPCCGT ST is assumed to trip 40 seconds later as it runs out of steam from the PPCCGT GTs.

Risk factor type 5 – interconnector flows exceeding thresholds

As for separations at [1] and [2] (discussed in Section 5.1.1), timestep effects and interconnector drift can lead to flows on the Heywood Interconnector exceeding the 3 Hz/s limit. These effects apply similarly to separation events at [3], [4] and [5]. No measures are proposed in this report for management of these risks.

Risk factor type 6 – over-frequency

Over-frequency scenarios typically occur when flows at the point of separation are exporting from South Australia to Victoria. RMS model studies show that separations at [3], [4] or [5] which lead to over-frequency conditions in South Australia can demonstrate stability and voltage risks. These include potential instabilities on QNI, as well as potential instability and voltage issues in South-West Victoria if there is high positive RoCoF following a separation at [5]. Further detail can be found in Appendix A3.4.2.

These conditions require further study to investigate possible management measures, and therefore are considered out of scope for this analysis.

6.2.2 Percentage of time at risk

The range of outcomes for the 2022-23 and 2023-24 forecast years for a “clean” double-circuit separation at Moorabool (point [5]) are summarised in Figure 16. Each dot represents a trading interval simulated in the MMM, with colours showing the case outcomes (blue: pass, orange: risk and red: fail). The various risk zones are indicated:

- Type 3 risk factors occur when RoCoF post separation (shown on the horizontal axis) exceeds 2 Hz/s, leading to possible trip of synchronous units.
- Type 4 risk factors occur when a trip of generation following separation exacerbates RoCoF, leading to a risk or fail scenario (possibly including a trip of a synchronous unit). The degree of exacerbation depends on the generation levels at the generating units that trip (shown on the vertical axis).

Figure 16 Distribution of frequency containment outcomes in 2022-23 and 2023-24 following a separation at Moorabool (point [5])

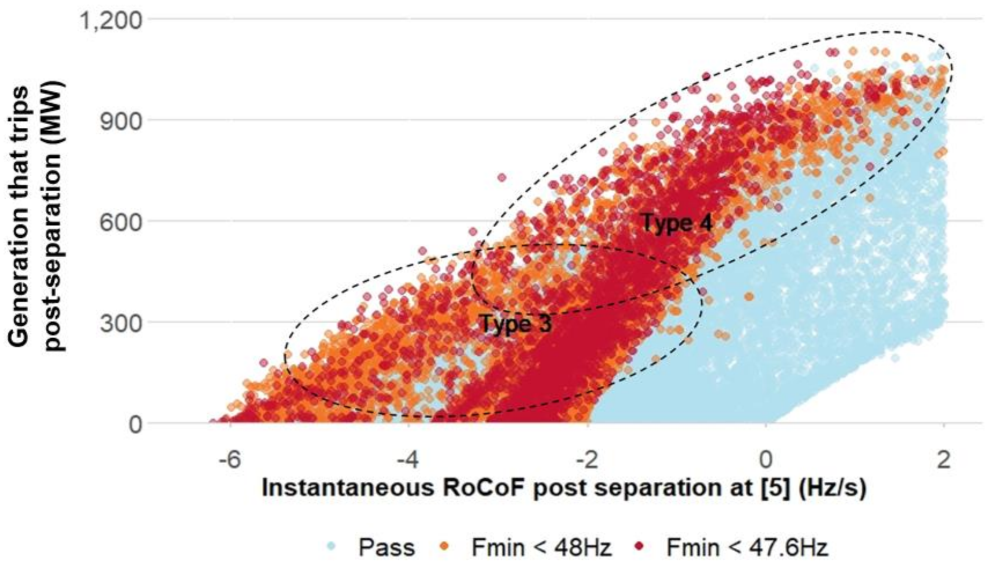


Table 19 summarises the approximate percentage of time affected by each type of risk factor, where it has been assessed in this report.

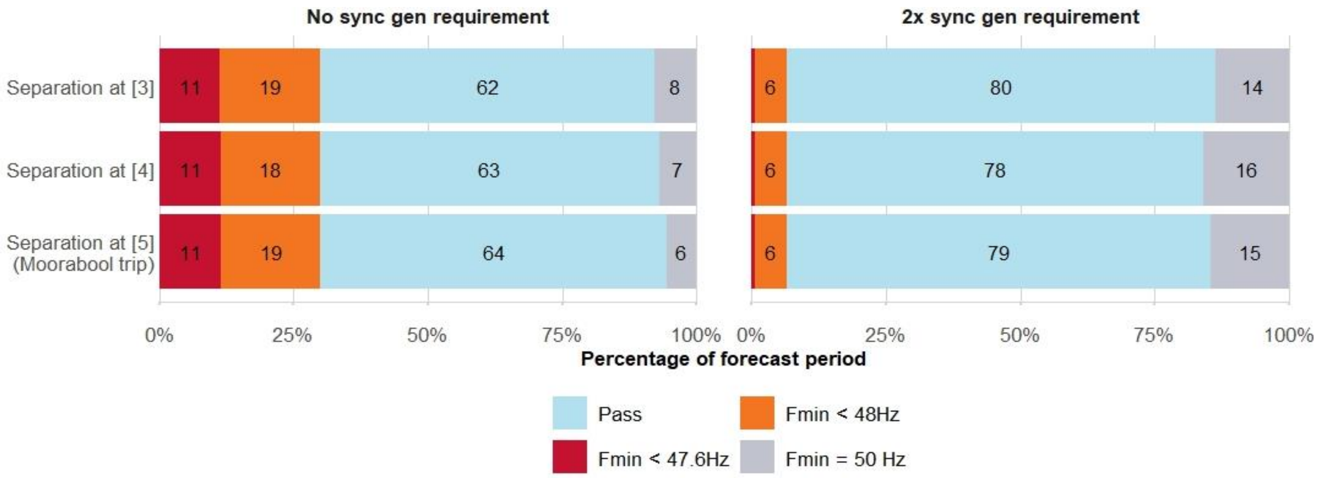
Table 19 Percentage of 2022-23 to 2023-24 at risk, for separation at [3], [4] or [5]

Risk factor	Failure mechanism	Percentage of 2022-23 to 2023-24 in this risk category (risk or fail outcomes)	
		2 x sync gen requirement	No sync gen requirement
Type 1	Low UFLS load	No additional risks identified beyond those for separations at [1] or [2]	
Type 2	High import with degraded UFLS or low inertia	No additional risks identified beyond those for separations at [1] or [2]	
Type 3	Extreme RoCoF leading to synchronous unit trip (Modelling assumes PPCCGT trips if RoCoF exceeds 2 Hz/s for ≥100 ms)	4%	19%
Type 4	Generation trip exacerbates contingency (Modelling assumes LKB 1-3 and CNUN WF trip 200ms after separation, alongside DD and SH WF trip as part of SWV GFT)	6%	26%
Type 5	Interconnector flows exceeding thresholds	Not quantified in these studies	
Type 6	Over frequency (up to 16% of trading intervals in 2022-23 to 2023-24)	Not quantified in these studies (out of scope)	

[A] Multiple risk factors may be present in a single period.

The amalgamated total percentage of time at risk (combining all factors without double counting where multiple risk factors arise in the same period) is summarised in Figure 17. Risk levels for separations at points [3], [4] or [5] were found to be similar.

Figure 17 Percentage of periods at risk (2022-23 and 2023-24) following a non-credible separation in the 500 kV South-West Victoria network



If no control measures are taken:

- For the scenario with no minimum synchronous generation requirements, approximately 30% of periods in 2022-23 to 2023-24 are identified be at risk.
- For the scenario where a minimum requirement of two synchronous units is maintained online in South Australia, around 6% of periods are identified to be at risk.

The different dispatch scenarios produce a wide range of forecast risks, and there is significant uncertainty over the forecast scenarios that may eventuate (even if future requirements for synchronous generating units were known at this time). In the no synchronous generator requirement scenario, 22% of periods in 2022-23 and

2023-24 show risk and fail outcomes when there is one or more synchronous unit online, so these risks do not solely occur in periods with no synchronous units online.

For this reason, the recommended management measures (outlined in Section 7) are designed to show a positive cost/benefit in both scenarios, because they bind only in periods where the real-time conditions indicate a risk is present.

6.3 Unserved energy estimates

Table 20 summarises estimates of the amount of USE and costs associated with USE risks, estimated based on the estimated likelihood of a black system event, and the range of possible USE associated with each black system event. Further details on the approach and assumptions are outlined in detail in Appendix A4.

Table 20 USE estimates – separation at [3], [4] or [5]

	USE (MWh/year)	Annual cost ($ million/year)	
		Standard VCR	2 x VCR
No minimum synchronous unit requirement (cost-reflective bidding profiles)	310-1,375	$15 - $68	$30 - $135
Minimum 2 synchronous unit requirement (historical bidding profiles)	53-236	$3 - $12	$5 - $23

7 Management options for frequency containment

This section outlines a series of options that have been explored to improve frequency containment outcomes for South Australian separation events at points [1] to [5] (Figure 13). These options are designed to address the various risks outlined in the previous sections.

7.1 Option 1: Restore UFLS or increase Emergency Under Frequency Response (EUFR)

Some of the risks identified are due to inadequate levels of emergency under-frequency response in South Australia, due to DPV reducing the net load in the UFLS scheme (discussed in Section 1). AEMO first highlighted these risks in the 2020 PSFRR[37], and recommended that SAPN and ElectraNet take immediate action to restore emergency under-frequency response as far as technically and economically feasible. As at March 2022, SAPN and ElectraNet have added up to 330 MW of distribution- and transmission-connected load to the scheme.

Since that time, a number of actions have been taken or are underway to restore emergency under-frequency response, as discussed in Section 4.4. These include adding almost all customer load in South Australia into the UFLS, implementing dynamic arming of UFLS relays (such that they will be disarmed/blocked when the circuit is in reverse flows)[38], and seeking expressions of interest for other possible sources of emergency under-frequency response from the market[39].

These actions are currently proceeding as they are required under existing responsibilities in the NER (under clause S5.1.10.1(a), NSPs must ensure that sufficient load is under the control of under-frequency relays or other facilities where required).

It is noted that when these rules were drafted it was not anticipated that there may be periods where sufficient conventional UFLS would not be readily available. Full restoration of emergency under-frequency response to previous levels may no longer be technically or economically feasible, and may not be necessary based on the power system risks arising in periods with low operational demand. AEMO has a program of work underway to determine the plausible non-credible contingency events that could occur in periods with high levels of DPV operating, and based on these to estimate the amount of emergency under-frequency response required to appropriately manage them. This will inform the appropriate level of investment in restoration of emergency under-frequency response.

[37] AEMO (July 2020) 2020 Power System Frequency Risk Review, Appendix A1, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-1/psfrr-stage-1-after-consultation.pdf?la=en&hash=A57E8CA017BA90B05DDD5BBBB86D19CD.

[38] AEMO (May 2021) South Australian Under Frequency Load Shedding – Dynamic Arming, https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf?la=en&hash=C82E09BBF2A112ED014F3436A18D836C.

[39] SA Power Networks, Expressions of Interest Emergency Under Frequency Response in South Australia, https://sapowernetworks.co/UFLS-EOI.

7.1.1 Additional costs

There are additional costs associated with restoration of emergency under-frequency response services. However, these are not considered in this report because they are works that will proceed under clause S5.1.10.1(a).

For example, the AER recently approved SAPN's application for a positive pass-through of $30.5 million to implement dynamic arming (reverse flow blocking) of UFLS relays[40]. Implementation is proceeding between 2022 and 2024.

7.1.2 Recommendation and status

AEMO recommends that cost-effective options to restore emergency under-frequency response in South Australia continue to be investigated. This is an existing NSP responsibility under NER clause S5.1.10.1(a).

The further options outlined below are intended as interim and complementary measures, on the understanding that full restoration of emergency under-frequency response will not be achieved quickly.

This recommendation targets risk factor type 1 (low UFLS load with moderate import) and risk factor type 2 (high import periods with degraded UFLS or low inertia), discussed in detail in Sections 5.1.1 and 6.2.1. As measures are progressively implemented to increase emergency under-frequency response, the other options outlined below are designed to automatically adjust to bind less and therefore incur less costs.

7.2 Option 2: Constrain Heywood imports

There is a set of constraints implemented at present under Regulation 88A which keeps Heywood Interconnector flows at a level where the South Australian UFLS scheme can effectively manage the non-credible loss of the interconnector. The constraint set is designed to dynamically manage imports into South Australia only when required to reduce risks of cascading failure due to inadequate UFLS availability, accounting for system inertia and FFR availability.

The proposed constraints take a similar form to the existing constraints and are intended to replace these existing constraints. The proposed constraints have been updated based on the latest information available.

7.2.1 Constraint development approach

Hundreds of thousands of simulations were performed across a range of dispatch scenarios, including the 2022 ISP market model and other possible 'worst-case' dispatch outcomes. Regression analysis was applied to these simulation results; this identified that the key factors impacting South Australian frequency following a non-credible separation are:

- Imports on the Heywood Interconnector,
- UFLS load,
- DPV generation,

[40] AER (16 September 2022) SA Power Networks – Cost pass through – Emergency standards 2021-22, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-pass-throughs/sa-power-networks-cost-pass-through-emergency-standards-2021%E2%80%9322

- Power system inertia, and
- The availability of FFR.

A set of constraints was designed to determine allowable imports on the Heywood Interconnector that reduce risks of cascading failure. The proposed constraints are summarised in Table 21 and the regression component of the constraint is illustrated in Figure 18.

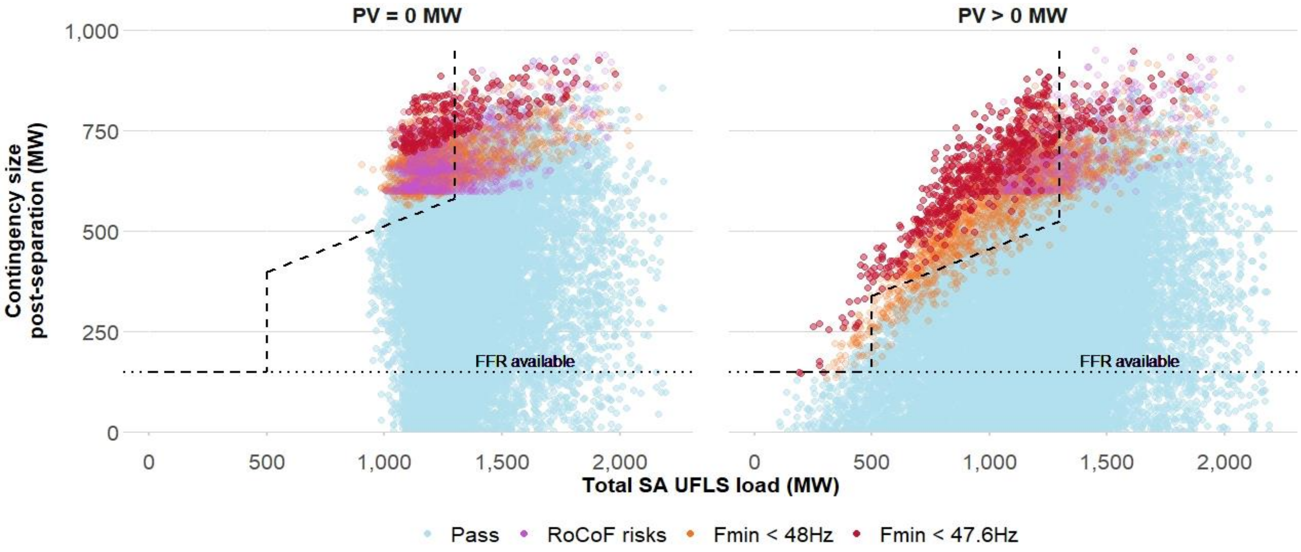
Table 21 Proposed updated Heywood constraints

<table>
<tr><th>Constraint</th><th colspan="2">Details</th><th>Explanation</th></tr>
<tr><td rowspan="4">Regression constraint</td><td>Total UFLS load in South Australia</td><td>Imports into South Australia across Heywood limited to:</td><td rowspan="4">• Limits Heywood imports into South Australia in periods where UFLS levels are low, accounting for available FFR, inertia and DPV generation.</td></tr>
<tr><td>Below 500 MW</td><td>Max of:
• Available FFR
• 0</td></tr>
<tr><td>500 MW to 1,300 MW</td><td>Max of:
• Available FFR – (LKB +CNUN)
• 70.9 + 0.034*Inertia – 0.058*DPV generation + 0.23*(UFLS load – 30) + 0.42*FFR – 25
• 0</td></tr>
<tr><td>Above 1,300 MW</td><td>No limit</td></tr>
<tr><td>RoCoF constraint</td><td colspan="2">Limit flows on the Heywood Interconnector to maintain instantaneous RoCoF following a non-credible separation below the following levels:
• ±3 Hz/s, or
• -2 Hz/s for imports into South Australia, if:
– South Australian operational demand ≤ 2,000 MW, and
– PPCCGT generation > 0.6*(FFR raise headroom) + 130.</td><td>• Reduces the risk of a possible generating unit trip on extreme RoCoF (discussed in Appendix A2).
• Maximises probability that UFLS will function properly to arrest frequency decline.
• The more onerous 2 Hz/s constraint only applies if PPCCGT is online and operating at high enough levels for a trip to have a reasonable risk of cascading failure (accounting for FFR availability), and for operational demand levels below 2,000 MW to avoid interacting with possible lack of reserve issues in high demand conditions.</td></tr>
</table>

Figure 18 provides a visual representation of the regression constraint. Each dot represents a simulation of one trading interval with various levels of Heywood imports and UFLS load. Blue dots signify simulations that met acceptance criteria, red dots simulations likely to lead to cascading failure, and orange dots conditions at 'risk' of cascading failure. Purple dots represent risks which are addressed by the RoCoF constraint (rather than the regression constraint).

The regression constraint is illustrated by the dashed black line, which indicates Heywood imports will be limited to this level and adjust based on real-time conditions.

Figure 18 Visual representation of proposed regression constraint



Illustrative case study

Figure 19 shows a case study illustrating the impact of the proposed Heywood constraint, with key events noted in Table 22.

Figure 19 Heywood regression constraint impacts: Case study (14:30, winter 2022)

	Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	DPV generation (MW)	Imports at Heywood (MW)	Synchronous generator dispatch
No action	916	736	4,400	890	520	None
Heywood constraint			~7,500		345	PPCCGT ST + 1xGT: 175 MW

Modelled UFLS load includes new loads added to the UFLS since 2020, and excludes dynamic arming

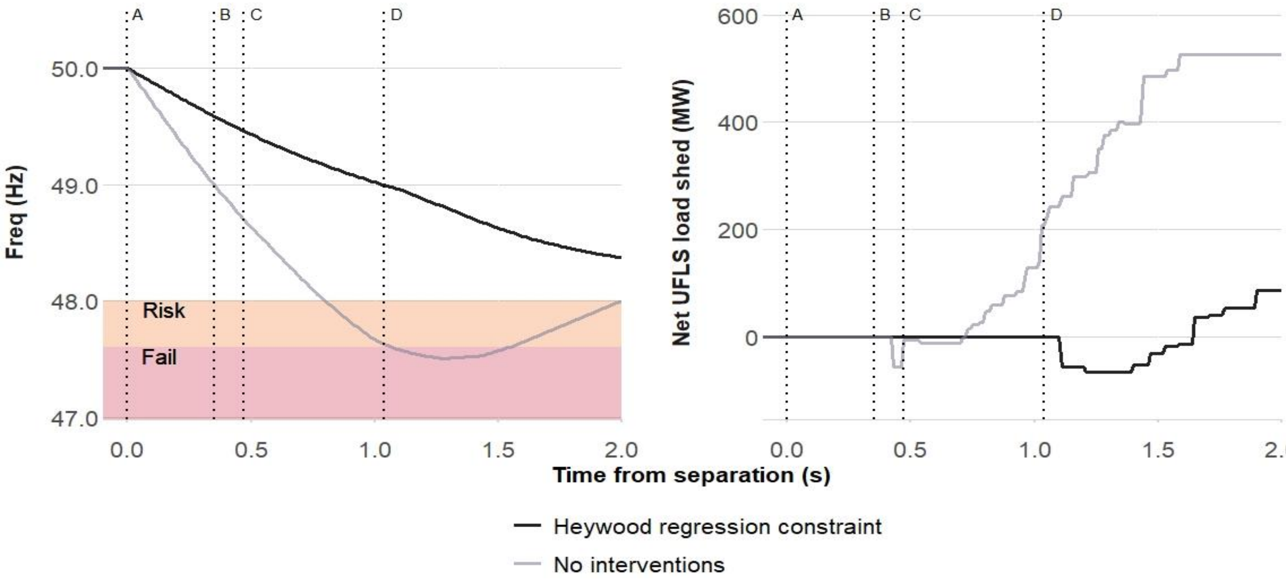


Table 22 Heywood regression constraint impacts: Case study key events (14:30, winter 2022)

	Time from separation	Event	Notes
A	0 s	Separation at Heywood ([1])	• Grey scenario: with no interventions, RoCoF is -2.9 Hz/s. • Black scenario: with the Heywood constraint, RoCoF is -1.2 Hz/s, as generation loss is smaller and inertia is higher with the constraint.
B	0.35 s	Grey scenario: frequency reaches 49Hz	• 80 ms following frequency reaching 49 Hz, ~65 MW of DPV trips due to DPV inverter settings (seen in the right panel).
C	0.47 s	Grey scenario: UFLS RoCoF relays trip	• 45 MW of UFLS load on RoCoF relays trips in response to the high RoCoF following separation. • The trip of RoCoF UFLS somewhat counteracts the 65 MW DPV trip, but this has limited impact in arresting frequency due to the reduced amount of load on UFLS. UFLS effectiveness has been reduced by DPV generation, with load on each band approximately 40% of what it would have been without DPV. • In this case, without the constraints, frequency reaches a minimum of 47.5 Hz (considered a "fail" case under acceptance criteria).
D	1.04 s	Black scenario: frequency reaches 49Hz	• 80 ms following frequency reaching 49 Hz, ~65 MW of DPV trips due to inverter settings (seen in the right panel). • As RoCoF in this scenario is higher, UFLS load on RoCoF relays does not trip and it takes a little longer for UFLS to counteract the impact of the initial 65 MW DPV trip. However, due to action of the Heywood constraint to limit contingency size, frequency remains above 48 Hz throughout the period, considered a "pass".

In this example period, the regression constraint binds to reduce imports on the Heywood Interconnector from 520 MW to 345 MW, and it is assumed that the difference in the supply-demand balance in the constrained case is met by PPCCGT being dispatched on. This increases inertia in South Australia, and the reduction in Heywood imports reduces the contingency size in the event of a non-credible separation.

The difference in the initial RoCoF between the two cases illustrates the twofold impact of the Heywood constraint; during periods where UFLS is insufficient to manage a separation, the constraint:

- Reduces the overall generation contingency from the loss of Heywood, and
- Increases inertia in South Australia, as synchronous generators are likely to be dispatched on in response to limits on Heywood.

7.2.2 Expected power system security outcomes

Estimated system security outcomes following the implementation of the Heywood constraints are summarised in Table 23 and Figure 20. The proposed Heywood constraints considerably reduce risk associated with a separation at [1] or [2], and also reduce risk for separations at [3], [4] or [5], although substantial residual risk remains for separations at [3], [4] or [5]. Further options are explored below to address this remaining risk.

Table 23 Estimated % of 2022-23 and 2023-24 at risk/fail following a non-credible separation: with and without Heywood constraints

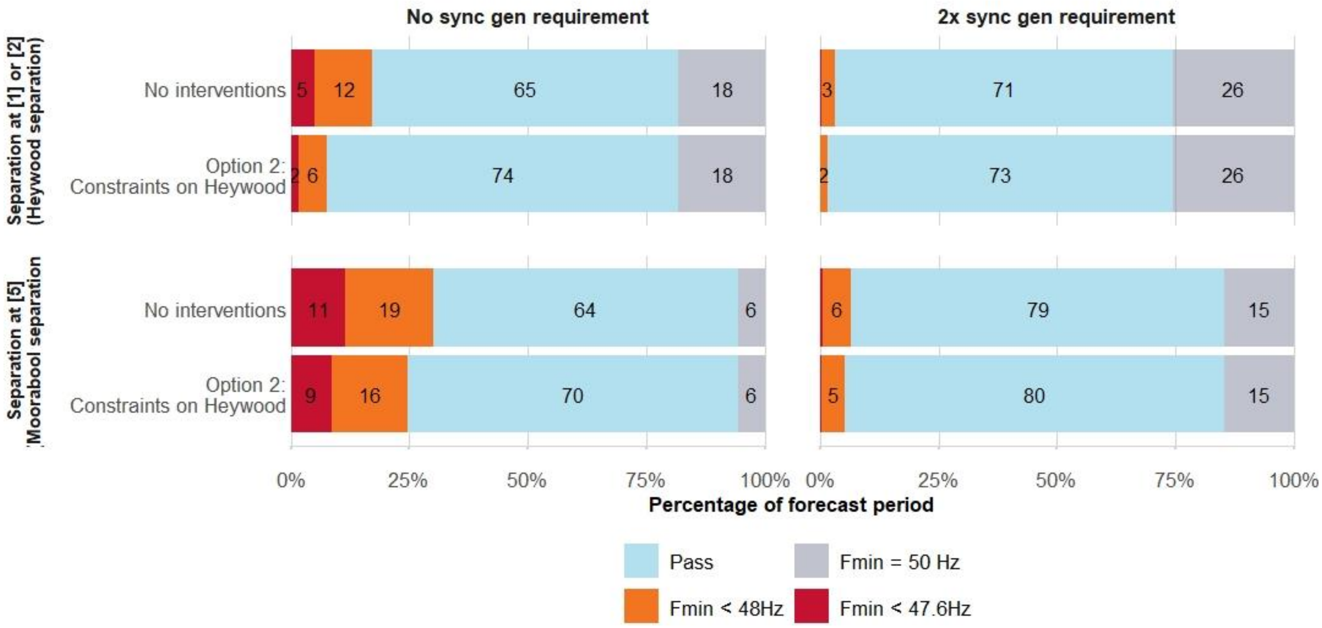
	Separation at [1] or [2]		Separation at [3], [4] or [5]	
Condition	**No sync gen requirement**	**2x sync gen requirement**	**No sync gen requirement**	**2x sync gen requirement**
No interventions	17%	3%	30%	6%
Heywood constraints implemented	8%	2%	25%	5%
Estimated reduction in risk/fail cases	**9%**	**1%**	**5%**	**1%**

When tested against the forecast with a minimum requirement for two synchronous generating units, the constraints show minimal change in risk outcomes because risk is already estimated to be low in this case.

Forecast dispatch patterns are strongly dependent on Plexos modelling assumptions, and AEMO recommends introducing these constraints as proposed, regardless of minimum synchronous unit requirements, so they protect against possible dispatch scenarios that can arise even if the two synchronous unit requirement is maintained. As the constraints update based on real-time conditions, they are expected to bind very rarely if risks are low, therefore incurring minimal market costs.

Due to Heywood drift and the timestep lag in constraint implementation (as described in Section 5.1.1), some level of residual risk will remain even for separation events at [1] or [2], since these risks are not addressed by the measures proposed in this report.

Figure 20 Impact of Option 2: Constraints on Heywood – % of periods in 2022-23 and 2023-24 at risk



7.2.3 Estimated costs and benefits

Constraint costs

The constraints percentage of time binding and likely impacts on system dispatch were calculated with a merit order algorithm, based on individual unit SRMC which account for fuel costs and efficiencies of different units. When the Heywood constraints bind, they limit interconnector flows into South Australia, which results in units being dispatched up in South Australia and downwards in Victoria. The difference in SRMC between these units was used to estimate total market costs of the constraints. Further details are in Appendix A4.

Constraint benefits

The constraints reduce the likelihood of cascading failure following a separation at Heywood.

- The Heywood regression constraint targets risk factor type 1 (low UFLS load with moderate import), risk factor type 2 (high import periods with degraded UFLS or low inertia), and risk factor type 4 (wind farm trip exacerbates contingency). These risk factors are discussed in detail in Sections 5.1.1 and 6.2.1.
- The Heywood RoCoF constraint targets risk factor type 3 (extreme RoCoF leading to synchronous unit trip). This risk factor is discussed in Sections 5.1.1 and 6.2.1.

This impact is estimated in terms of reduced risk, quantified as annual USE reduction in each half-hourly interval in 2022-23 to 2023-24 (with the 'no intervention' case compared against a case with the proposed constraints in place). The financial benefit associated with reducing USE was then estimated based on the standard VCR or 2 x VCR, summarised in more detail in Appendix A4.

Net benefits

The overall cost-benefit calculation for the Heywood constraints is shown in Table 24. This calculation assumes:

- A separation has a 50% likelihood of occurring at Heywood (points [1] or [2]), and a 50% likelihood of occurring in South-West Victoria (point [3],[4] or [5]). Hence, the USE values from Table 16 and Table 20 sum together to the 'estimated USE' column.
- 'Risk' cases have 50% likelihood of leading to cascading failure, and 'fail' cases have 100% likelihood of cascading failure (specified further in Table 9).

The final scenario-weighted central estimate of net benefit of the proposed constraints across all separation points is shown in bold.

Table 24 Costs and benefits for Option 2: Constraint on Heywood imports, 2023-23 and 2023-24

	Percentage of period binding (%)	Estimated USE (MWh)	Reduction in USE from constraints (MWh/year)	Estimated benefits ($mil/year)		Estimated costs ($mil/year)	Estimated net benefit ($mil/year)	
				Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement	17%	477 to 2,116	135 to 601	$7 to $30	$13 to $59	$12	-$5 to $18 **Central: $6**	$1 to $47 **Central: $23**
Minimum 2 synchronous unit requirement	4%	79 to 352	25 to 110	$1 to $5	$2 to $11	$2.4	-$1 to $3 **Central: $0.8**	$0 to $8 **Central: $4**

This analysis indicates a net positive benefit in all central estimate net benefit scenarios considered.

7.2.4 Recommendation

AEMO recommends that the proposed constraints be implemented. These constraints are designed to automatically adjust for ongoing changes to the availability of FFR, UFLS, DPV and inertia.

The constraints proposed are similar to a set already applied in the NEM at present (implemented under Regulation 88A[41]). The proposed constraints above have been re-tuned to account for more recent adjustments to

[41] Government of South Australia, *Electricity (General) (Provision of Limit Advice) Variation Regulations 2016*, No 240 of 2016 published in Gazette 12.10.2016 p 3994, https://www.legislation.sa.gov.au/__legislation/lz/v/r/2016/electricity%20(general)%20 (provision%20 of%20limit%20advice)%20variation%20regulations%202016_240/2016.240.un.pdf.

the South Australian UFLS scheme (particularly the addition of new loads into the scheme), and on the basis of the most recent forecast dispatch scenarios. The proposal above will also ease the existing 2 Hz/s RoCoF import limit from 2 Hz/s to 3 Hz/s, during periods where PPCCGT is not operating.

The RoCoF limit applied should be reviewed as further evidence becomes available on RoCoF ride-through capabilities of generating units in South Australia, discussed further in Section 7.3.

7.3 Option 3A: Physical testing of synchronous unit RoCoF withstand capabilities

As outlined in Section 4.5, the available evidence suggests that the RoCoF ride-through capability of some synchronous units may be in the region where management measures are required in some periods, but the exact ride-through capabilities of these units are unknown.

7.3.1 Sensitivity to RoCoF ride-through assumptions

Figure 21 summarises the difference in the risk profile if the PPCCGT GTs can ride through high RoCoF. This reduces the estimate of total periods at risk:

- In the no synchronous generator requirement case, from 30% to 12% of 2022-23 to 2023-24.
- In the 2 x synchronous generator requirement case, from 6% to 3% of 2022-23 to 2023-24.

An additional sensitivity that assumed the PPCCGT GTs can ride through up to 250 ms at 2 Hz/s (instead of 100 ms assumed in the baseline scenario) was also considered.

Figure 21 Impact of generator RoCoF ride-through assumptions: % of 2022-23 to 2023-24 at risk following separation at [5]

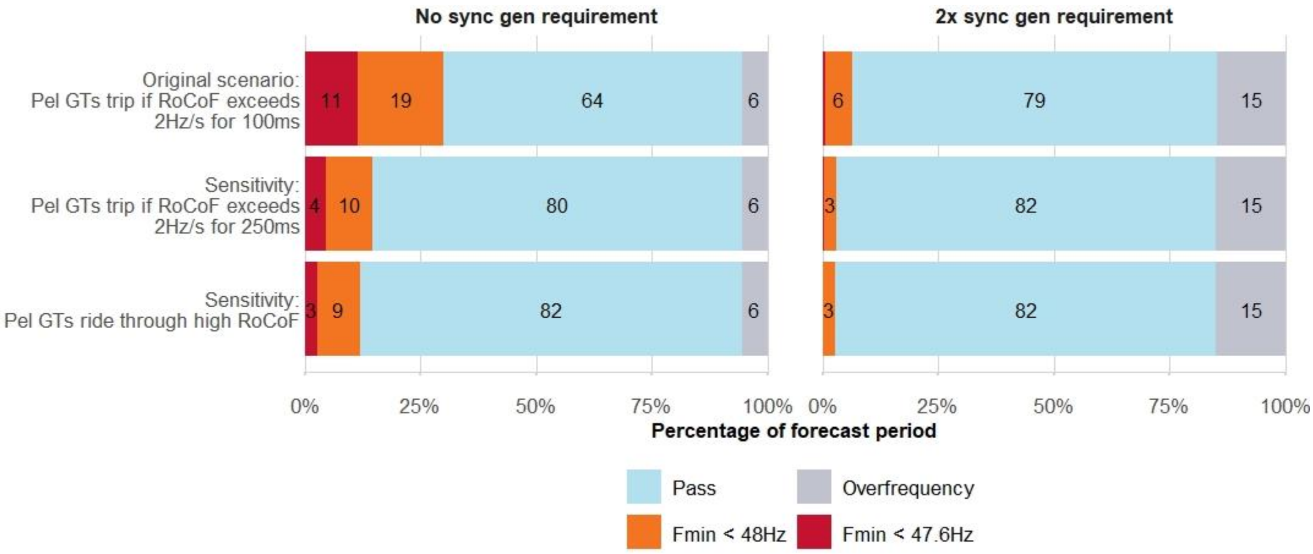


Table 25 shows the significance of the difference in the PPCCGT RoCoF ride-through assumption in terms of the difference in estimated USE and USE costs.

This highlights the value in better understanding the RoCoF ride-through capabilities of synchronous generating units, particularly those that operate often and can have a significant impact on the power system if they trip (due to their large capacity and inertia levels).

Table 25 Impact of PPCCGT RoCoF ride-through behaviour (2022-23 and 2023-24)

	Difference in USE from PPCCGT ride-through assumption[A] (MWh/year)	Estimated difference in USE costs ($mil/year)	
		Standard VCR	2 x VCR
No minimum synchronous unit requirement	252 to 1,119	$12 to $55	$25 to $110
Minimum 2 synchronous unit requirement	35 to 156	$2 to $8	$3 to $15

A. Difference in USE if the PPCCGT GTs can ride through RoCoF exceeding -2 Hz/s for 100 ms, versus riding through all levels of RoCoF.

This highlights the value in better understanding the RoCoF ride-through capabilities of synchronous generating units, particularly those that operate often and can have a significant impact on the power system if they trip (due to their large capacity and inertia levels).

7.3.2 Physical unit testing

One option is to physically test the ride-through capability of the relevant generating units. International experiences suggest that testing of all units in South Australia is likely to be too costly to be warranted, and is not recommended. AEMO proposes that testing should focus on confirming the capabilities of selected units only, focusing on those that are likely to have more vulnerability to extreme RoCoF, and which can have a large impact on system frequency if they trip.

PPCCGT has been identified as a large, high inertia unit that may be vulnerable to RoCoF, and which has an important influence on the power system if it trips.

AEMO has sought information from PPCCGT's operator Engie, and Engie has sought advice from the original equipment manufacturer (OEM). The OEM advised that no further information is available at this time on the PPCCGT RoCoF ride-through capabilities, but physical testing of the unit would be feasible. The OEM has provided indicative costs for testing the RoCoF ride-through capabilities of the units at PPCCGT (see below).

Testing process

EirGrid (system operator for Ireland) has developed and extensively applied a RoCoF Test Procedure[42], which could provide a guide for similar physical testing to be conducted for selected units in the NEM. The EirGrid tests verify governor response to a simulated RoCoF event by injecting a simulated frequency into the governor and recording the unit's response. The EirGrid tests were typically performed with the synchronous unit running at baseload for some time before frequency injection, and the unit governor isolated from system frequency.

Typical test frequency profiles can be either:

- Historical event frequency traces, or

[42] EirGrid Group, *Rate of Change of Frequency Test Procedure*, Nov 2016, https://www.eirgridgroup.com/site-files/library/EirGrid/RoCoF-Testing-Procedure.docx.

- Speed traces which are likely to define the unit's technical operating envelope, such as the worst case frequency profile the unit would be expected to ride through.

At present, testing governor response to RoCoF is the main form of RoCoF withstand testing available for existing units. The test focuses on governor response and does not cover the full range of possible RoCoF trip mechanisms (discussed further in Section 4.5). While physical testing would provide some confidence in the unit's RoCoF ride-through capabilities, it does not comprehensively rule out the possibility of the unit tripping off on RoCoF due to unexpected interactions beyond governor controls. Further methods to test RoCoF ride-through capability may emerge as power systems in Australia and around the world are faced with higher levels of RoCoF.

In the South-West Interconnected System (SWIS) in Western Australia, Market Participants and Network Operators will soon be able to seek accreditation for RoCoF ride-through capability to determine if their unit will be required to provide cost recovery for the RoCoF control service in development as part of Frequency Co-Optimised Essential System Services (FCESS) for the provision of inertia[43]. This accreditation can be supported by one the following items, otherwise AEMO would deem the RoCoF ride-through capabilities of the facilities as 0.5 Hz/s over 500 ms and the facilities are considered causer for cost recovery purposes:

- The facility's continuous uninterrupted operation over 1 second as specified under the registered GPS.
- Evidence that demonstrates the facility's ability to maintain continuous uninterrupted operation under a range of RoCoF events.
- An engineering study that considers RoCoF ride-through capability in the context of key risks for each equipment type, based on GE's 2016 review of power system elements[44] (detailed in Section 4.5).

As RoCoF testing procedures develop, more methods and test procedures may become available which may provide a further view on the RoCoF ride-through capability of key synchronous generators in South Australia.

Costs

Physical testing of governor response to RoCoF might be expected to take approximately one day depending on the number of tests, and would need be conducted when the unit is out of service. This could perhaps be coordinated with other maintenance works. The PPCCGT OEM indicated cost estimates for two test frequency profiles, with costs increasing if more test profiles are included.

A range of conditions which likely affect RoCoF ride-through (for example, fault type and active/reactive power output of the unit, discussed further in Appendix A2) could also be tested, so management measures could be nuanced to minimise market impacts.

Benefits

Unit testing would allow targeted management of power system risks with more accurate knowledge of the RoCoF ride-through requirements of synchronous units. Unnecessary market intervention can be avoided, and there is higher confidence that system security risks are being appropriately managed.

[43] AEMO, *Guideline: Rate of Change of Frequency Sensitive Equipment*, available at https://aemo.com.au/-/media/files/electricity/wem/participant_information/guides-and-useful-information/guideline-rocof-sensitive-equipment.pdf?la=en&hash=17DD7A14789D07E5CBC47D3D5EAD3B82.

[44] GE Energy Consulting 2017, *Advisory on Equipment Limits associated with High RoCoF*, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/20170904-GE-RoCoF-Advisory.

7.3.3 Recommendation

AEMO recommends that the possibility of physically testing the RoCoF ride-through capabilities of PPCCGT is explored. This may provide increased confidence around the units' capabilities, so management measures can be better tailored. PPCCGT is the highest priority generator in South Australia as it may have a relatively higher risk of tripping in response to extreme RoCoF, and has high inertia and generation capacity which can have meaningful impacts on power system outcomes following a non-credible separation. RoCoF testing could be considered in future for other units in the NEM if there is reason to believe they may be at elevated risk.

This recommendation will further investigate risk factor type 3 (extreme RoCoF leading to synchronous unit trip). This risk factor is discussed in detail in Sections 5.1.1 and 6.2.1.

7.3.4 Implementation pathways

AEMO proposes to investigate the feasibility of physical RoCoF testing with the PPCCGT station operator and the relevant OEM. This should include assessment of:

- The technical feasibility of the testing process.
- The degree to which the testing process will provide increased confidence in the unit RoCoF ride-through capabilities (some tests may only test certain elements of unit performance).
- The costs involved, and whether these are likely warranted given the anticipated benefits.
- The timeframe for testing to be conducted, and whether it can be completed sufficiently in advance of the commissioning of PEC Stage 2 (beyond which the likelihood of severe RoCoF events may be reduced).

If the testing process appears technically and economically feasible, and can be conducted in a useful timeframe to deliver benefits prior to PEC Stage 2 commissioning, and will provide useful insight, it may be worth proceeding with physical testing.

7.4 Option 4: Modification to control schemes in South-West Victoria

AEMO has explored a number of possible options to modify or optimise the operation of control schemes in South-West Victoria to minimise some of the risks identified for separations in this part of the network.

7.4.1 EAPT "Mode Switching" algorithm

As noted in Section 6.2.1, some of the risks identified for a non-credible separation occurring in the South-West Victoria network were related to possible slower operation of the EAPT scheme when in Mode 1. EAPT activation following a separation in South-West Victoria acts to slow RoCoF[45]. If the EAPT scheme operates very quickly, generating units in South Australia are exposed to extreme RoCoF levels for a shorter duration, minimising the risk of generating unit tripping.

As discussed in Section 6.1.1, the EAPT scheme operates very quickly when it is in Mode 2 (topological activation criteria only). EAPT operation can be much slower when it is in Mode 1 (both topological and performance activation criteria) if the performance criteria are not met immediately following separation.

[45] The EAPT scheme is described in detail in Section 6.1.1.

The EAPT is intended to be kept in Mode 1 most of the time to minimise the risks of spurious operation. AEMO investigated an algorithm that automatically switched EAPT to Mode 2 during periods with risks of extreme RoCoF that might lead to generating unit tripping. This algorithm was termed EAPT "mode switching" and is described in Table 26.

The algorithm was intended to allow EAPT to operate as quickly as possible under high risk conditions, minimising the time that generating units in South Australia are exposed to extreme RoCoF, and thereby reducing the risk of unit trips.

Table 26 EAPT 'mode switching' algorithm

Power system condition	EAPT mode	Estimated % of 2022-23 to 2023-24 in this mode
Most of the time	Mode 1	77%
If: • **Large synchronous units with RoCoF vulnerability are generating, and** • **Instantaneous RoCoF following a separation at [3][A] exceeds -2 Hz/s**	Mode 2	23%

A. The physical network configuration in South-West Victoria means a separation at [3] produces the highest RoCoFs post-separation, due to Stockyard Hill and Dundonnell wind farms and Mortlake GT being located on the Victorian side of the separation. Because the SWV GFT operates to trip Dundonnell and Stockyard Hill wind farms following a separation at [4] or [5], and Mortlake GT is a peaking unit that operates rarely, system security risks remain similar across separations at [3], [4] or [5], as shown in Section 6.2.2.

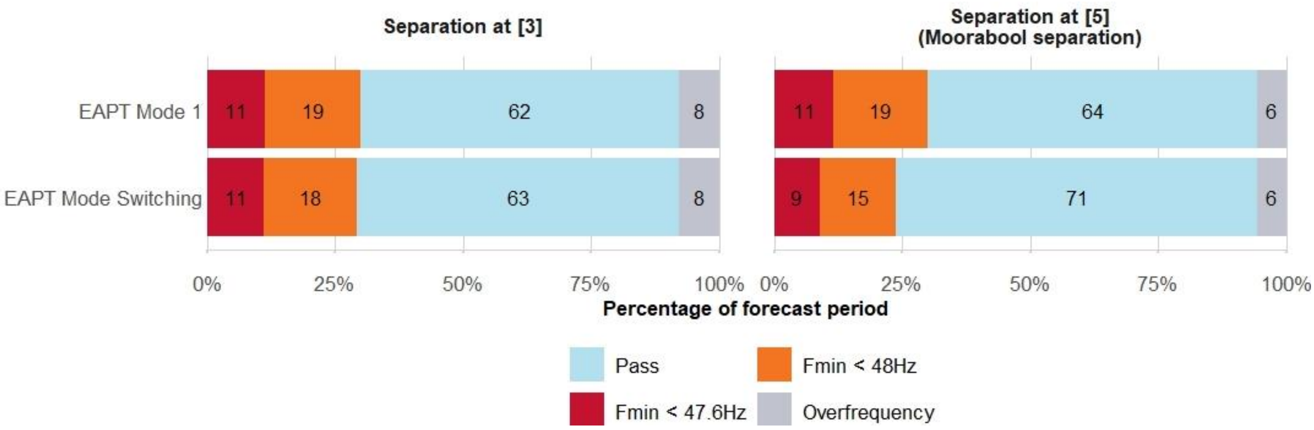
Expected power system security outcomes

Studies to investigate this possibility were pursued in consultation with the EAPT scheme designers, utilising MMM outcomes benchmarked against an RMS model. A RoCoF proxy was developed for the MMM, with good frequency matching across RMS model cases (discussed in Section 6.1.1 and Appendix A3.4.3). Applying this proxy, for a separation at [5], up to 6% of periods showed some benefit from EAPT mode switching. However, AEMO believes EAPT mode switching may offer minimal benefit in reducing system security risks, due to the following factors:

- Events with the highest risks of synchronous unit tripping are those with higher RoCoF. RMS model and MMM benchmarking suggest that under high RoCoF conditions, EAPT is likely to operate rapidly in both Mode 1 and Mode 2 (that is, 'rapid' Mode 1 operation occurs).
- Most of the modelled benefit from EAPT mode switching comes from cases where RoCoF was just slightly under the -2 Hz/s RoCoF proxy threshold for 'rapid' EAPT Mode 1 operation (Section 6.1.1). Due to uncertainty around frequency transients and the RoCoF proxies used in the modelling, it is possible rapid EAPT Mode 1 operation may actually occur in these periods as well.
- Although mode switching demonstrated some benefits in the model for a separation at [5], when considering a separation at [3], EAPT Mode 1 and Mode 2 were found to have almost identical system security outcomes, as shown in Figure 22. This means that additional management measures would be required to manage separations at [3], even if the EAPT mode switching algorithm was introduced.

- There are risks of unintended impacts. The incoming EAPT upgrade was developed to reduce risks of scheme mal-operation[46]. Enabling EAPT Mode 2 under a larger proportion of system conditions may result in a higher risk of mal-operation, or other unintended power system impacts.

Figure 22 Impact of EAPT mode switching: % of 2022-23 to 2023-24 at risk, no synchronous generator requirement scenario



Costs

The mode-switching algorithm will be non-trivial to implement, involving further cost to study and design, and would likely delay implementation of the proposed EAPT upgrade.

Recommendation

For the reasons outlined above, AEMO does not recommend further pursuing implementation of this approach.

7.4.2 Selectively disable South-West Victoria Generator Fast Trip (SWV GFT) scheme on Dundonnell and Stockyard Hill Wind Farms

Following a separation at points [4] or [5], the SWV GFT scheme activates on topological criteria (detection of circuit breaker opening) to trip Dundonnell and Stockyard Hill wind farms 170 ms after the separation. The SWV GFT is in place to avoid instability due to low short circuit ratios (SCR) in South-West Victoria post-separation.

As noted in Section 6.2.1 (risk factor type 4), SWV GFT activation may disconnect up to 850 MW of generation, which can exacerbate risks in separations leading to under-frequency.

AEMO investigated if selectively disarming the SWV GFT under some conditions might improve frequency outcomes for South Australia. EMT studies (conducted in PSCAD) showed that even the mildest possible separation at Moorabool (point [5]) resulted in the loss of Dundonnell and Stockyard Hill wind farms, regardless of

[46] In 2018, lightning strikes leading to the loss of QNI caused EAPT to mal-operate and separate South Australia when the region was exporting energy to Victoria. Although EAPT operated in accordance with its design, the scheme was not designed for the circumstances of the 2018 event.

AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018*, January 2019, available: https://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?la=en&hash=49B5296CF683E6748DD8D05E012E901C.

whether the GFT was present. Disarming the GFT would therefore provide no benefit for improving frequency outcomes in South Australia.

Recommendation

Selective disarming of the SWV GFT is not recommended. EMT studies show that even the mildest possible separation at [5] would result in the trip of Dundonnell and Stockyard Hill wind farms due to low system strength in the South-West Victoria network. The SWV GFT operation results in more stable disconnection of these wind farms and should remain in place.

7.5 Option 5: Address RoCoF protection on wind farms

As noted in Section 4.5, two wind farms in South Australia have existing anti-islanding protection settings that trip the generators if RoCoF exceeds ±1 Hz/s for more than 1 second. These protection settings have been modelled in all studies in this report.

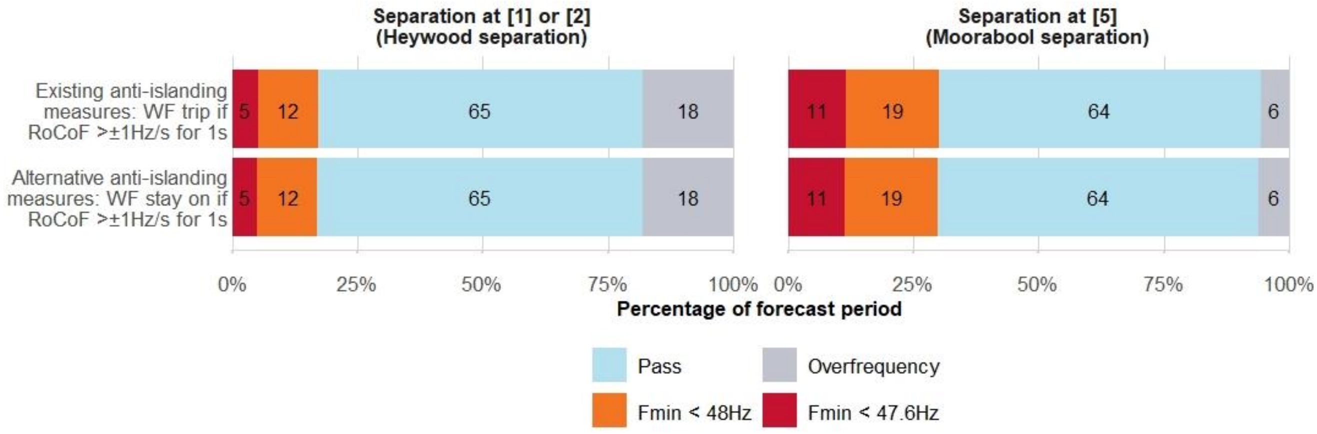
Tripping of these generating units in extreme under-frequency scenarios in response to rapidly falling frequency could further exacerbate the frequency decline. The impact of these settings was therefore investigated.

7.5.1 Sensitivity to wind farm RoCoF trip assumption

Figure 23 shows the impact of the two wind farms' anti-islanding RoCoF protection on power system security, comparing the original scenario (including the RoCoF protection as it exists at present) against a counterfactual where this protection is disabled (assumed to be replaced with an alternative anti-islanding protection system that does not trigger under these conditions). This sensitivity demonstrates that these settings do not contribute significantly to power system risk because:

- There is a minimum one-second delay in the trip of the wind farms post-separation, which means UFLS and FFR have already begun to respond to the initial frequency decline and are better able to respond to the subsequent loss of generation.
- The RoCoF protection settings only trigger to trip more than 50 MW of generation in 15% of cases, meaning the loss of generation is typically low when the protection settings activate.

Figure 23 Impact of RoCoF-based anti-islanding protection: % of periods in 2022-23 and 2023-24 at risk, no synchronous generator requirement scenario



7.5.2 Recommendation

Changing protection systems often requires engagement of the OEM, and is rarely trivial, especially on older generating units. Given that this protection setting triggers so rarely and has minimal adverse impact on power system security, AEMO does not recommend pursuing changes to these systems.

7.6 Option 6: Address generation tripping

As discussed in Section 4.6, the EMT models provided to AEMO to represent two wind farms (LKB1-3 and CNUN) indicate that these wind farms may trip following a South Australian separation event.

7.6.1 Sensitivity to trip assumption

Figure 24 shows that power system security risks are meaningfully affected by the trip of these wind farms. Risks associated with a separation at [1] or [2] are reduced from 17% of the time to 9% of the time if these wind farms remain connected and stable. Similarly, risks associated with a separation at [5] are reduced from 30% to 22% of the time.

Figure 24 Impact of unit trip: % of periods in 2022-23 and 2023-24 at risk, no sync gen requirement scenario

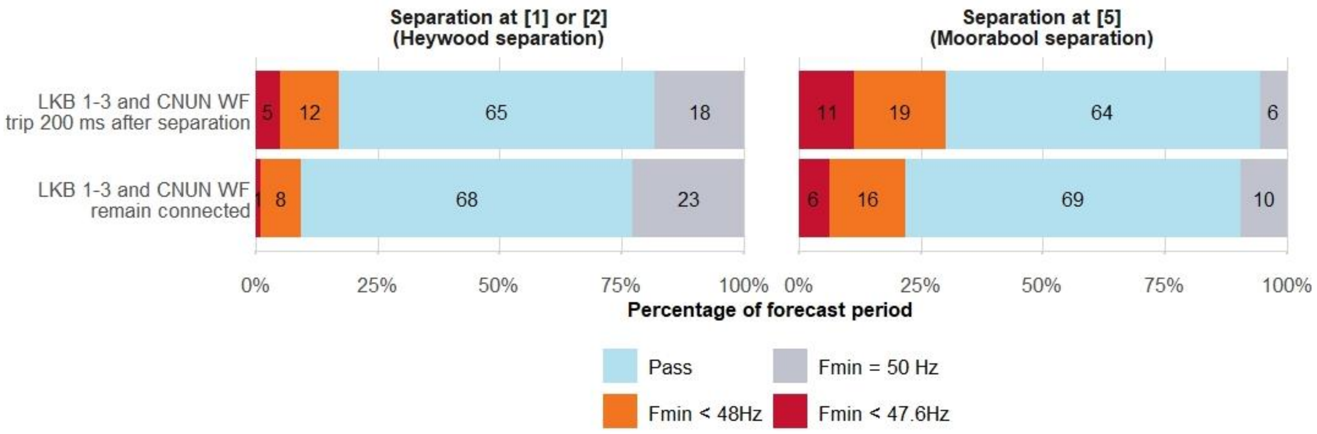


Table 27 shows the significance of the difference in the LKB1-3 and CNUN trip assumption in terms of the difference in estimated USE and USE costs.

Table 27 Impact of LKB1-3 and CNUN trip behaviour (2022-23 and 2023-24)

	Difference in USE from LKB and CNUN trip assumption[A] (MWh/year)	Estimated difference in USE costs ($mil/year)	
		Standard VCR	2 x VCR
No minimum synchronous unit requirement	188 to 834	$9 to $41	$18 to $82
Minimum 2 synchronous unit requirement	49 to 216	$2 to $11	$5 to $21

A. Difference in USE if LKB and CNUN remain connected through a South Australian separation event, versus staying connected.

This provides an indication of the value in addressing this behaviour.

7.6.2 Address tripping behaviour

AEMO is obligated to operate the power system securely and must do so on the basis of models provided. LKB1-3 and CNUN wind farms were commissioned prior to the requirement to supply EMT models to AEMO, and models were subsequently developed and provided.

If trip behaviour is addressed and AEMO is provided with accurate models that do not demonstrate this behaviour, these wind farms could be removed from the constraints proposed in this report to manage separation events (meaning these constraints would bind less, increasing inter-regional power transfer capability).

7.6.3 Recommendation

This option aimed to address risk factor type 4 (generation trip exacerbates contingency), discussed in detail in Sections 5.1.1 and 6.2.1. However, it is not recommended because AEMO understands that unit operators have already exhaustively explored further options to investigate and address this behaviour.

Tripping behaviour is assumed in the design of other management measures proposed; if this tripping behaviour can be rectified, other management measures can be eased, reducing system costs.

7.7 Option 7: Constrain imports in South-West Victoria

The constraints on imports on the Heywood Interconnector proposed in Option 2 (Section 7.2) are designed to manage a separation occurring at the Heywood Interconnector, but leave significant residual risk associated with separations at points [3], [4] and [5]. Much of this risk is associated with extreme RoCoF levels which can occur following a separation at [3], [4] or [5], possibly leading to a trip of a large synchronous unit. Additional management measures are hence required to reduce the risk of cascading failure under certain conditions for separations at [3], [4] or [5].

7.7.1 Constraint design

AEMO investigated applying an additional constraint on network flows in South-West Victoria to keep RoCoF in South Australia below -2 Hz/s following a separation at points [3], [4] or [5]. Designed to selectively constrain the network only when required, the South-West Victoria constraint is designed to be applied in addition to the proposed Heywood constraints and is described further in Table 28.

Table 28 South-West Victoria constraint algorithm

Constraint	Details	Explanation
South-West Victoria constraint	If: • South Australian operational demand ≤ 2,000 MW, and • PPCCGT generation > FFR raise headroom + 70, and • Instantaneous RoCoF following a separation at [3][A] exceeds 2 Hz/s (accounting for real-time generation levels in South-West Victoria and South Australia), Then: • Constrain imports into South Australia at [3] to below -2 Hz/s.	• Limits import into South Australia during periods where a possible station trip in response to high RoCoF could lead to cascading failure. • Only applies when South Australian operational demand is less than 2,000 MW to avoid having detrimental reliability impacts during lack of reserve conditions.

A. The physical network configuration in South-West Victoria means a separation at [3] produces the highest RoCoFs post-separation, due to Stockyard Hill and Dundonnell wind farms and Mortlake GT being located on the Victorian side of the separation. However, the Stockyard Hill and Dundonnell wind farms' GFT, combined with the fact that Mortlake GT is a peaking unit and therefore operates rarely, means system security risks remain similar across separations at [3], [4] or [5], as shown in Section 6.2.2.

7.7.2 Costs and benefits

As summarised in Section 7.2.3 and detailed in Appendix A4:

- Constraint costs and percentage of time binding were estimated based on a merit order algorithm. When the South-West Victoria constraint binds, gas units are typically dispatched up in South Australia and coal units dispatched down in Victoria.
- Constraint benefits are calculated in terms of reduced risk of cascading failure in South Australia following a separation in South-West Victoria (points [3] to [5]). This impact is quantified as annual USE reduction and the associated financial benefit estimated based on VCR.

The overall cost-benefit calculation for the South-West Victoria constraint is shown in Table 29, with the final scenario-weighted central estimate of net benefit of the proposed constraints across all separation points shown in bold.

Table 29 Costs and benefits for a South-West Victoria network constraint (2022-23 and 2023-24)

	Percentage of period binding (%)	Estimated USE (MWh/year)	Reduction in USE from constraint (MWh/year)	Estimated benefits ($mil/year)		Estimated costs ($mil/year)	Estimated net benefit ($mil/year)	
				Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement	32%	477 to 2,116	266 to 1,179	$13 to $58	$26 to $116	$47	-$33 to $12 **Central: -$12**	-$20 to $69 **Central: $23**
Minimum 2 synchronous unit requirement	8%	79 to 352	15 to 66	$1 to $3	$1 to $7	$5	-$4 to -$2 **Central: -$3**	-$4 to $1 **Central: -$1**

This analysis indicates a negative net benefit in nearly all central estimate net benefit scenarios considered. Constraint costs are relatively high since relatively cheaper coal generation in Victoria is replaced by relatively higher-cost gas generation in South Australia.

7.7.3 Recommendation

This analysis suggests that constraining network flows in South-West Victoria is a relatively higher cost management option, which does not consistently lead to a positive net benefit estimate under all circumstances. AEMO therefore does not recommend proceeding with this option at this time, and has explored other alternatives (outlined below).

7.8 Option 3B: Constrain RoCoF-vulnerable generating units

A large proportion of the risks identified for a separation in the South-West Victoria network (at [3], [4] or [5]) are associated with the possible trip of a large station in response to extreme RoCoF. To minimise the risks of cascading failure in South Australia, AEMO considered an alternative constraint formulation that reduces generation at RoCoF-vulnerable units in periods of high RoCoF risk.

Option 3B was designed to be applied in addition to Option 2 (constrain Heywood imports), and results in lower system costs than Option 7 (constrain South-West Victoria imports) because it involves constraining down gas-fired generation in South Australia, which is likely to be replaced with other similar cost gas-fired generation in South Australia. In contrast, Option 7 would constrain down network flows, leading to lower cost generation in Victoria being turned down.

7.8.1 Constraint development approach

A constraint was designed to identify scenarios that lead to "fail" or "risk" outcomes following a separation at [3], [4] or [5], if PPCCGT is assumed to trip when RoCoF exceeds ±2 Hz/s for more than 100 ms. Hundreds of thousands of simulations were performed in the MMM across a range of dispatch scenarios, including the 2022 ISP market model.

Regression analysis applied to these simulation results identified that the following factors significantly influenced outcomes, and therefore should be terms appearing in the constraint:

- FFR availability.
- RoCoF following a separation at [3], [4] or [5], which is affected by inertia in the resultant island, power flows across the point of separation, and generation that trips following separation (Section 4.6).

A possible constraint formulation that has been tuned to PPCCGT is shown in Table 30. The constraint adjusts dynamically in real-time to constrain the station generation down to minimum generation only when required.

This constraint does not aim to prevent the initial separation event or prevent the subsequent possible trip of a synchronous unit, but rather aims to minimise the probability of cascading failure if these events occur. Constraining the synchronous unit to minimum generation may also improve its RoCoF ride-through capability to some degree (as discussed in Section 4.5), although this potential additional effect is not captured in the modelling presented here.

Table 30 Possible constraint formulation applied for analysis

Details	Explanation
If: • South Australian operational demand ≤ 2,000 MW, and • PPCCGT generation > FFR raise headroom + 70, and • Instantaneous RoCoF following a separation at [3][A] (calculated based on real-time flows at [3]) exceeds 2 Hz/s, Constrain PPCCGT to the minimum generation level for each unit that is online (for example, if PPCCGT ST + 2 x GT is online, constrain to the minimum generation on all three units).	• Limits the consequences of a possible synchronous station trip in response to RoCoF exceeding ±2 Hz/s for 100 ms following a separation at [3], [4] or [5]. • Only applies when SA operational demand is less than 2,000 MW to avoid having detrimental reliability impacts during lack of reserve conditions.

A. The physical network configuration in South-West Victoria means a separation at [3] produces the highest RoCoFs post-separation, due to Stockyard Hill and Dundonnell Wind Farms and Mortlake GT being located on the Victorian side of the separation. However, the SWV GFT (on Stockyard Hill and Dundonnell Wind Farm), combined with the fact that Mortlake GT is a peaking unit and therefore rarely operates, means system security risks remain similar across separations at [3], [4] or [5], as shown in Section 6.2.2.

Illustrative case study

Figure 25 illustrates the constraint behaviour in a case study, with key events noted in Table 31. In this high risk period, the constraint acts to reduce station generation to minimum. The merit order algorithm indicates that Osborne Power Station (OSB) and BIPS would come online to meet demand in South Australia. This has the dual benefit of increasing system inertia and reducing the contingency size associated with a station trip.

Figure 25 Impacts of constraint on RoCoF vulnerable generating units: Case study (03:00, summer 2023)

	Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	Generation tripped on SWV GFT (MW)	Imports at Heywood (point [1]) (MW)	Imports at Moorabool (point [5]) (MW)	Synchronous generator dispatch
No intervention	1,406	1,131	~9,000	125	510	796	PPCCGT ST+2xGT: 483 MW
With constraint			~10,500				PPCCGT ST+2xGT at min gen. OSB ST+GT BIPS

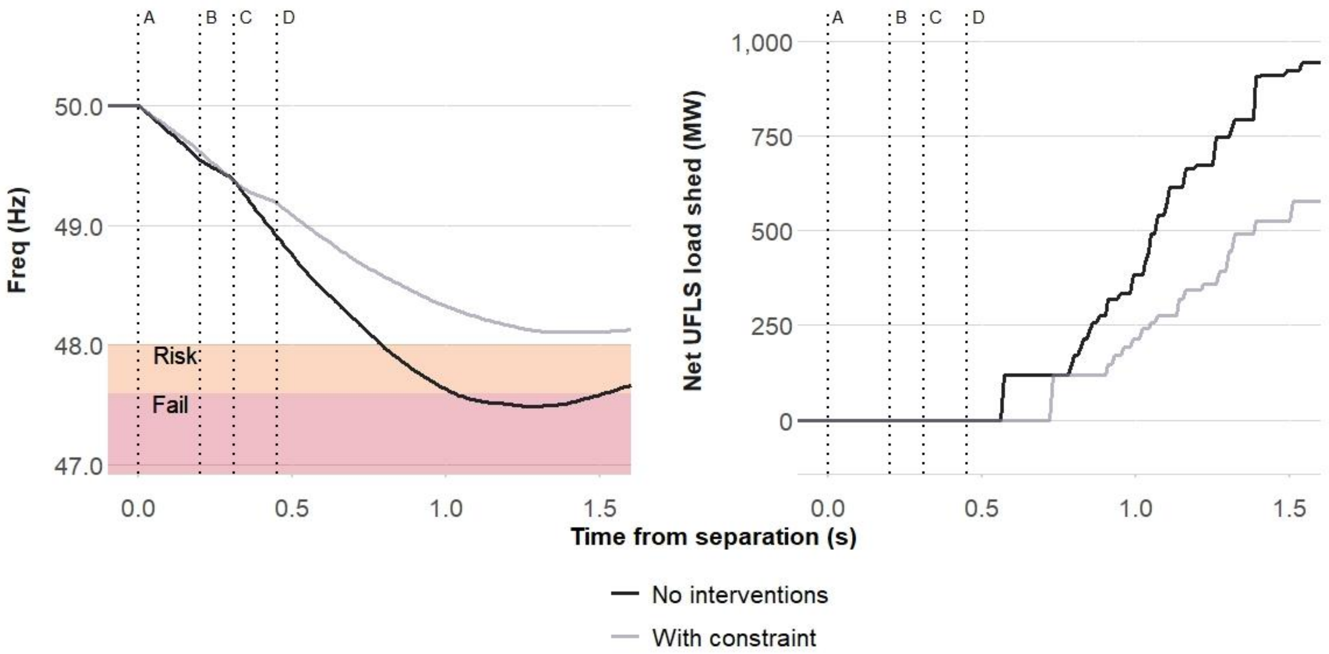


Table 31 Impacts of constraint on RoCoF vulnerable generating units: Case study key events (03:00, summer 2023)

	Time from separation	Event	Notes
A	0 s	Separation at [5]	• Black scenario: RoCoF post-separation is -2.2 Hz/s (100 ms average). • Grey scenario: RoCoF post-separation is -1.9 Hz/s (100 ms average). • RoCoF is lower in the constrained case due to higher system inertia.
B	0.2 s	EAPT operates (black scenario)	• Reduces average RoCoF in the black scenario to approximately -1.4 Hz/s (100 ms average).
C	0.31 s	PPCCGT GTs trip[A] (black scenario)	• RoCoF exceeded 2 Hz/s for >100 ms, leading to PPCCGT GT trip. Loss of inertia and generation leads to sharp frequency decline. • In the black scenario, the loss of generation and the inertia from the PPCCGT GTs (total station generation of 483 MW includes ST generation[A]) leads to RoCoFs accelerating to -3.3 Hz/s and a frequency nadir of 47.5 Hz, a 'fail' case.
D	0.45 s	PPCCGT GTs trip (grey scenario)	• Grey scenario: the loss of the PPCCGT GTs at minimum generation leads to a frequency nadir of 48.1 Hz (a 'pass' case). RoCoF is slowed due to the smaller generation loss, as well as the presence of the other GTs in South Australia.

A. The PPCCGT ST is assumed to trip 40 seconds later as it runs out of steam from the PPCCGT GTs.

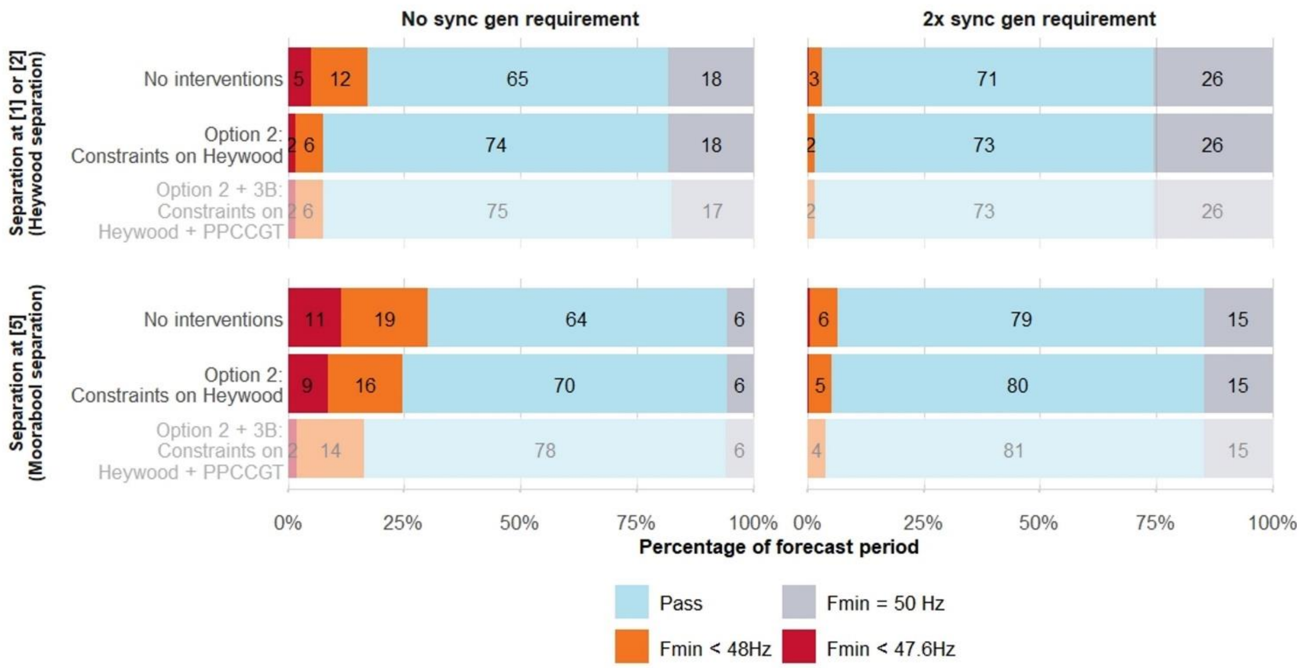
In the case with no interventions (black), nearly 1,000 MW of UFLS load trips, but the loss of generation and inertia from the PPCCGT GTs mean frequency falls below 47.6 Hz and the case is considered a "fail". In contrast, in the scenario with the constraint (grey), reduced contingency size and increased inertia levels for South Australia mean frequency is arrested above 48 Hz, considered a "pass" under acceptance criteria.

The benefit of the constraint is reduced somewhat if other forms of low-inertia generation (such as inverter-based resources, BESS) come online to fill the generation gap. However, sensitivity studies indicate the constraint remains robust in preventing risk outcomes just through the reduction in contingency size.

7.8.2 Expected power system security outcomes

Estimated system security outcomes following the implementation of the constraint are summarised in Figure 26. The constraint is applied in conjunction with the proposed Heywood import constraints (Option 2, discussed in Section 7.2). In the forecast with no minimum synchronous unit requirements, fail scenarios for a separation at [5] are reduced from 9% of periods to 2% of periods, and the total proportion of time at risk reduces from 25% of the time to 13% of the time.

Figure 26 Impact of Option 3B: constraint on RoCoF-vulnerable units – % of 2022-23 to 2023-24 at risk following separation



Outcomes are shown for a separation at [5]. System security risks are similar for separations at [3], [4] or [5], as shown in Section 6.2.2 (Figure 17), and risk reduction is also similar for separations at [3] to [5].

Regardless of decisions around minimum synchronous unit requirements in South Australia, risks can arise even in scenarios where minimum synchronous unit requirements are maintained, and the incidence of these periods may not be well captured by the Plexos forecast dispatch patterns. The constraints act to reduce risk periods when they arise, and bind rarely if these periods do not arise.

As shown in Figure 26, some residual risk periods remain even with the application of the Heywood and synchronous unit constraints. In these periods, AEMO's analysis indicates a reasonable likelihood that South Australia will not meet the frequency containment requirements defined in the FOS. More aggressive management measures (such as more heavily binding system constraints, incurring higher costs) would be required to address all identified risk periods.

7.8.3 Estimated costs and benefits

The overall cost-benefit calculation for the PPCCGT constraint is shown in Table 32. The central net benefit estimate is shown in bold.

- Constraint costs and percentage of time binding have been estimated based on a merit order algorithm. When the constraint binds, PPCCGT is dispatched down to minimum and the merit order algorithm indicates that another gas unit in South Australia is likely to be dispatched up.
- Constraint benefits have been estimated in terms of reduced risk of cascading failure in South Australia following a separation in South-West Victoria (points [3] to [5]). This impact is quantified as annual USE reduction.

These calculations are summarised in more detail in Appendix A4.

Table 32 Costs and benefits for Option 2 (+ Option 3B): Constraints on Heywood (and specific generating units), 2022-23 and 2023-24

	Percentage of period binding	Reduction in USE from constraints (MWh/year)	Estimated benefits ($mil/year)		Estimated costs ($mil/year)	Estimated net benefit ($mil/year)	
			Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement	32%	271 to 1,202	$13 to $59	$27 to $118	$17	-$4 to $42 **Central: $18**	$9 to $101 **Central: $53**
Minimum 2 synchronous unit requirement	8%	35 to 156	$2 to $8	$3 to $15	$3	-$1 to $5 **Central: $2**	$0 to $12 **Central: $6**

This analysis indicates a positive net benefit in all central estimate net benefit scenarios considered.

7.8.4 Recommendations

This recommendation targets risk factor type 3 (extreme RoCoF leading to synchronous unit trip). This risk factor is discussed in detail in Sections 5.1.1 and 6.2.1.

At this time, AEMO does not recommend implementing a constraint on specific generating units based on the present evidence available. The constraint demonstrates a positive cost/benefit for the assumed PPCCGT RoCoF withstand capabilities (trip for RoCoF>±2Hz/s for 100ms), but this is highly uncertain. The actual ride-through capabilities of the unit (and therefore the actual benefits of constraining the unit) are unknown.

A constraint of this form could be implemented in future if further evidence indicates this would be beneficial. Constraints could also be considered for other units in the NEM in future if there is reason to believe they may be at elevated risk.

7.9 Additional sensitivities

With Project Energy Connect Stage 1 (PEC1) and potential new BESS arriving in South Australia in the next few years, the effectiveness of the proposed management measures was evaluated in two key sensitivities.

7.9.1 PEC Stage 1

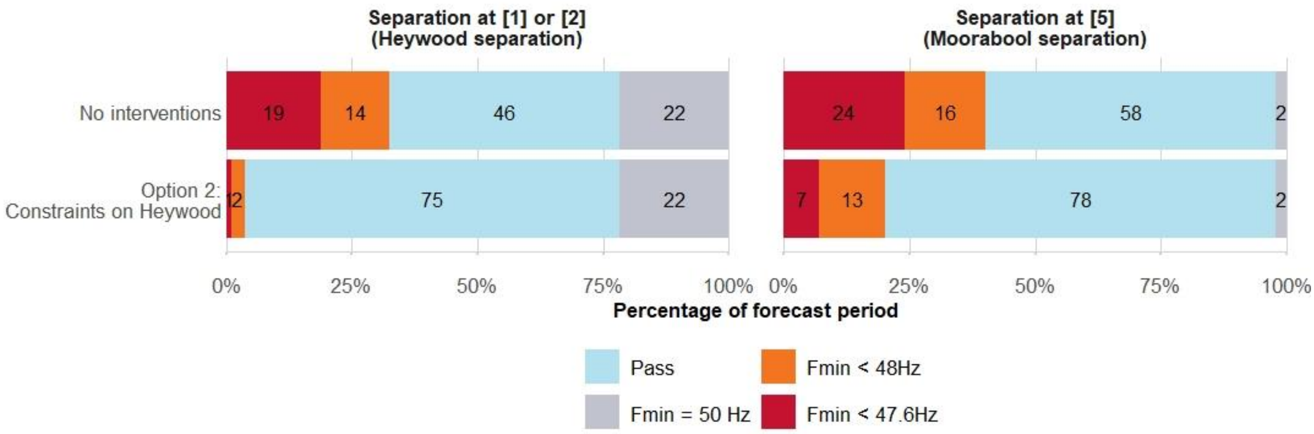
Project Energy Connect Stage 1 (PEC1) will add an additional 150 MW import capacity into South Australia. PEC1 is designed to intertrip following a separation at Heywood, meaning South Australia can still island if a separation occurs between Heywood and Moorabool (at points [1] to [5]).

When PEC1 is commissioned, it is proposed that flows on PEC1 will be added to the total contingency size in any constraints or management measures applied (PEC1 flows would be added to Heywood Interconnector flows and any wind farms that trip upon separation). This will mean that the total contingency is properly accounted for.

To confirm this approach is suitable, a sensitivity study was evaluated, applying a "worst-case" approach where imports were increased by 150 MW (the maximum PEC1 capacity) in all periods, and the impact of the combined trip of both interconnectors was considered in the MMM.

Figure 27 shows the power system security outcomes using this "worst-case" approach, demonstrating that Option 2 remains a robust way of managing risk if the total contingency size is accounted for in the constraint design. Option 2 also continues to demonstrate a positive net benefit in the central cost estimate case for the PEC1 sensitivity.

Figure 27 Impact of PEC1: % of 2023-24 at risk, no synchronous generator requirement scenario



7.9.2 Torrens BESS

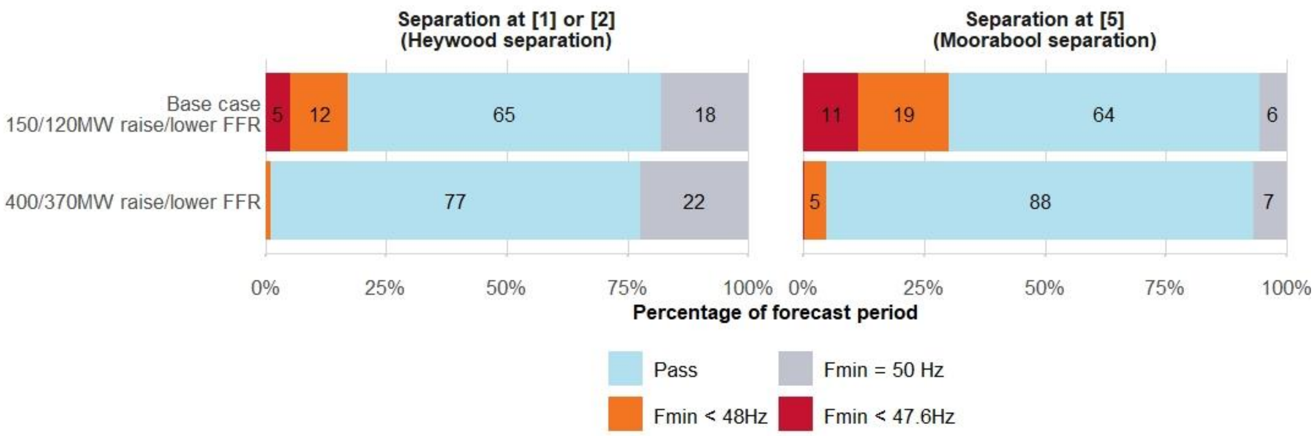
At the time of modelling, the 250 MW Torrens BESS is considered 'anticipated'[47] and thus was not modelled in the market model dispatch forecast (Section 4.2). However, the arrival of this new BESS will affect frequency containment outcomes for South Australia.

A sensitivity was modelled where the Torrens BESS was assumed to operate in a similar manner to the Hornsdale BESS, with Torrens BESS generation capacity (250 MW) available to provide FFR in most periods. This would mean that a total of approximately 400 MW of FFR could be present in South Australia following a separation. Results for this sensitivity are shown in Figure 28.

[47] AEMO 2022, *NEM Generation Information August 2022*, available: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2022/nem-generation-information-august-2022.xlsx?la=en. The Torrens BESS remains 'anticipated' in the January 2023 Generation Information update.

Because the proposed Option 2 constraints bind less when levels of FFR increase, the management measures proposed in this analysis continue to demonstrate positive net benefit in the central cost estimate.

Figure 28 Impact of Torrens BESS: % of 2023-24 at risk, no synchronous generator requirement scenario



7.9.3 Recommendations

It is therefore proposed that the proposed measures remain appropriate (with the total contingency size accounted for in the constraints) and this report's recommendations should be sustained. The measures proposed here will require further study following full commissioning of PEC Stage 2.

7.10 Summary of recommended options

The options considered and the recommendations for each are summarised in Table 33. Details on all risk factors are discussed in Section 5.1.1 and 6.2.1, and the various recommended options are discussed in Section 7.

Table 33 Management options for frequency containment

Options	Details	Recommendation	
Option 1: Restore UFLS or increase Emergency Under Frequency Response (EUFR)	Take actions to restore UFLS or develop alternative sources of EUFR, as far as technically and economically feasible.	✓	• AEMO has already recommended this action to SA Power Networks (SAPN) and ElectraNet (as far as technically and economically feasible) • This work is already underway, and falls under existing network service provider (NSP) responsibilities defined in NER S5.1.10.1(a). • This cannot be fully addressed quickly, so other management measures are proposed below as a stop-gap measure. As EUFR is restored, these other management measures are designed to progressively ease.
Option 2: Constrain Heywood imports	Constrain imports into South Australia during high-risk periods: • where there is insufficient emergency under-frequency response (including UFLS) to manage a clean double-circuit separation at [1] or [2], or • if RoCoF post-separation might exceed the withstand thresholds for units online.	✓	• Effective constraints are currently implemented under regulation 88A of the South Australian *Electricity (General) Regulations 2012* (Regulation 88A)[A] to limit RoCoF in South Australia to 3 Hz/s for a non-credible loss of the Heywood Interconnector. • Constraint formulations have been reviewed based on latest forecasts and system conditions, with fine tuning proposed to maintain efficacy.

Options	Details		Recommendation
Option 3A: Physical testing of synchronous unit RoCoF withstand capabilities	Explore feasibility of physical testing of selected synchronous generating units to develop more insight into RoCoF withstand capabilities. PPCCGT is noted as the highest priority.	?	• Noting the plant age, technology and modelling capability[B], investigate feasibility of testing as a first step, exploring costs, expected timelines, and the level of confidence in RoCoF withstand capabilities that could be achieved by testing.
Option 4: Modification to control schemes in South-West Victoria	Explore several options to modify control schemes in the South-West Victoria network to better manage the brief period of extreme RoCoF that can occur following non-credible separation events at [3], [4] or [5].	✗	• Modifications to EAPT scheme unlikely to result in reduced risk and may have unintended consequences. • Selective disarming of SWV GFT scheme infeasible since this is required to manage system strength issues. • Do not recommend.
Option 5: Address RoCoF protection on wind farms	Remove/replace specific RoCoF anti-islanding protection on two wind farms in South Australia	✗	• Studies indicate this does not materially reduce risk. • Do not recommend.
Option 6: Address generation tripping	Identify and if possible address the cause of LKB and CNUN wind farm instability and tripping behaviour demonstrated in EMT models (provided to AEMO)[C] following separation events when operating above thresholds.	✗	• Unit operators advise they have already extensively explored options to investigate and address this behaviour. • Tripping behaviour is assumed in design of other management measures proposed; if this tripping behaviour can be rectified then other management measures can be eased, reducing system costs.
Option 7: Constrain imports in South-West Victoria	Explored implementation of a constraint that reduces network flows in South-West Victoria to reduce RoCoF following a non-credible separation at [3] to below thresholds that might lead to synchronous generator tripping in South Australia.	✗	• High market cost. By constraining network flows, the constraint acts to dispatch down lower cost generation in Victoria, typically replaced with higher cost gas-fired generation in South Australia. • Do not recommend.
Option 3B: Constrain RoCoF-vulnerable generating units	Implement a constraint that reduces dispatch of units identified to be vulnerable to extreme RoCoF to minimum generation in periods where there is a risk of unit trip following a separation in the South-West Victoria network. This aims to minimise likelihood of cascading failure in the event of a unit trip. Designed to complement constraints on Heywood imports (Option 2). This does not completely remove security risks, but reduces them significantly.	✗	• Directly constraining synchronous units to minimum generation has a relatively lower cost than constraining network flows in South-West Victoria. The constraint typically replaces unit generation with similar cost generation in South Australia. • Do not recommend implementing based on present evidence available. The constraint demonstrates a positive cost/benefit for the assumed PPCCGT RoCoF withstand capabilities (trip for RoCoF>±2 Hz/s for 100 ms), but actual RoCoF capability is highly uncertain. Actual benefits are unknown. • Could be implemented in future if further evidence indicates this would be beneficial.

A. Regulation 88A was introduced by the *Electricity (General) (Provision of Limit Advice) Variation Regulations 2016*, No 240 of 2016.
B. Associated with the challenge of undertaking detailed modelling of electrical and mechanical components to evaluate generator ride-through performance for large RoCoF events.
C. AEMO, *Transfer Limit Advice – System Strength in SA and Victoria*, April 2023, Section 2.2, https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

8 Frequency stabilisation and recovery

This section analyses the frequency recovery requirements associated with a non-credible separation event: achieving frequency stabilisation to 49 Hz within two minutes following separation, and recovery to 49.5 Hz within 10 minutes following separation.

The analysis outlined in this section is all based on a non-credible double-circuit loss of the Heywood Interconnector. Findings for frequency stabilisation and recovery are expected to be similar for separation events occurring at other locations in the network.

8.1 Approach and assumptions

8.1.1 Model for analysis of frequency recovery

The model used for frequency recovery studies is an extension of the MMM used for frequency containment studies, making it suitable to assess frequency over a 10-minute time frame.

In addition to elements in the frequency containment MMM (applied in the earlier sections of this report and summarised in Section 4.3), the frequency recovery model includes a **detailed DPV disconnection/ curtailment and reconnection model.** DPV can disconnect or curtail in the initial separation. Any DPV that is disconnected or curtailed during the initial event will reconnect progressively in the minutes following separation, depending on how the power system recovers, calibrated based on field measurements and inverter bench testing[48].

Sensitivity analysis was also used to explore varying assumptions for regulation FCAS dispatch, and ramping and unpredictable variations in load, and semi-scheduled and non-scheduled generators.

Appendix A1 provides further details on the modelling assumptions applied.

8.1.2 Power system behaviour following separation

Frequency recovery following a severe non-credible contingency can be affected by a combination of delayed contingency FCAS, regulation FCAS and central dispatch via the NEM dispatch engine (NEMDE). Under a NEM intact system normal condition, at present there is no regional requirement to have any FCAS services enabled in South Australia and therefore FCAS are not guaranteed to be present in a South Australia island following a non-credible separation event.

Historical events have shown that it can take 10-15 minutes for AEMO to confirm a non-credible separation and reconfigure the system for islanded operation of South Australia. The actions required include:

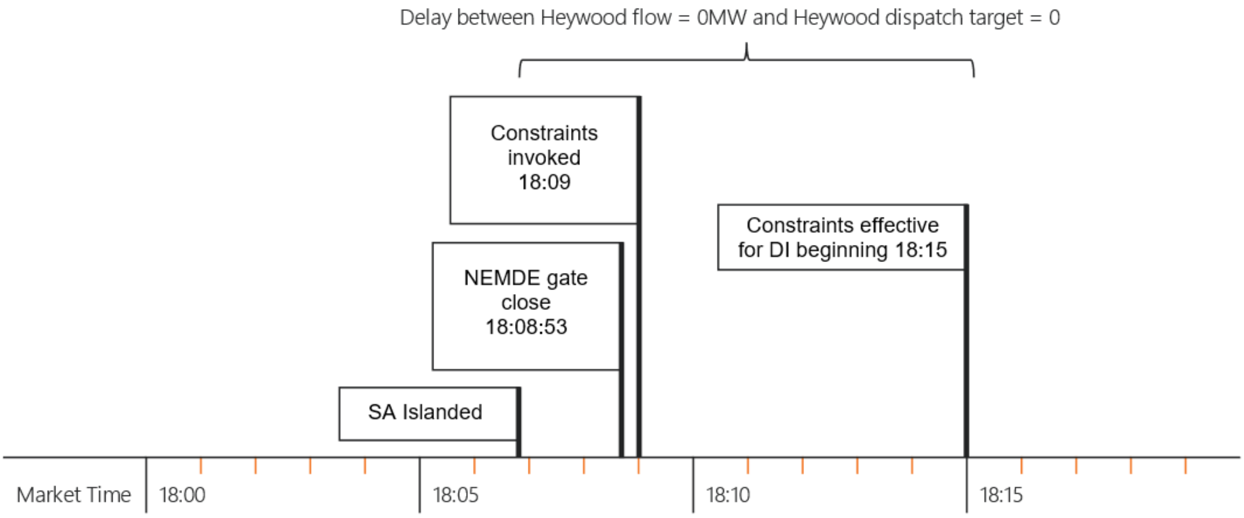
- Confirmation of formation of an island (for example, confirming observations are not due to a SCADA error) and identifying the boundaries.
- Invocation of constraints (including FCAS requirements) for islanded operation.

[48] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

- Re-configuration of Automatic Generation Control (AGC) for secondary frequency control based on a South Australia frequency reference.
- Manual interventions for essential system services such as system strength and inertia.

During the first 10-15 minutes following a non-credible separation event, before the necessary elements are reconfigured, frequency control is largely reliant on the automatic responses of resources within the South Australian island. As an example, Figure 29 shows the timeline observed following the non-credible separation event that occurred on 16 November 2019[49]. In this example, there is a delay of several minutes following the separation until the necessary constraints are invoked, and then a further six minutes before those constraints are effective in dispatch. Generating units will then take some time to respond.

Figure 29 Timeline following separation event on 16 November 2019



Source: AEMO (December 2019) *Preliminary Report Non-Credible Separation Event South Australia – Victoria on 16 November 2019*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2019/preliminary-incident-report---16-november-2019---sa---vic-separation.pdf?la=en&hash=F26C20C49BD51164AE700A30F696A511.

Table 34 summarises the frequency outcomes of islanded regions following non-credible separation events in the past five years. Coincidentally, these events all occurred during periods of export resulting in an over-frequency condition following separation. It is expected that similar dynamics would occur during periods of import/under-frequency.

Table 34 Frequency outcomes following non-credible separation events

Date and time	Island	Region export	Frequency zenith	Time above 51 Hz	Time above 50.5 Hz	Time until AGC reconfigured and FCAS constraints invoked
25/08/2018 13:11	QLD	870 MW	50.9 Hz	0 s	608 s	499 s
25/08/2018 13:11	SA	170 MW	50.46 Hz	0 s	0 s	493 s
16/11/2019 18:06	SA	307 MW	50.7 Hz	0 s	~400 s	493 s
31/01/2020 13:24	SA	531 MW	51.11 Hz	~2 s	~36 s	~630 s
12/11/2022 16:39	SA	208 MW	50.53 Hz	0 s	~2 s	~660 s

[49] In November 2021, NEMDE gate closure time was reduced from 67 seconds to 15 seconds (AEMO (November 2021), AEMO Fortnightly Operational Industry Briefing). This may somewhat improve the time required following constraint invocation, but it does not significantly reduce frequency recovery risks, because total time requirements are more influenced by the manual actions taken by the control room.

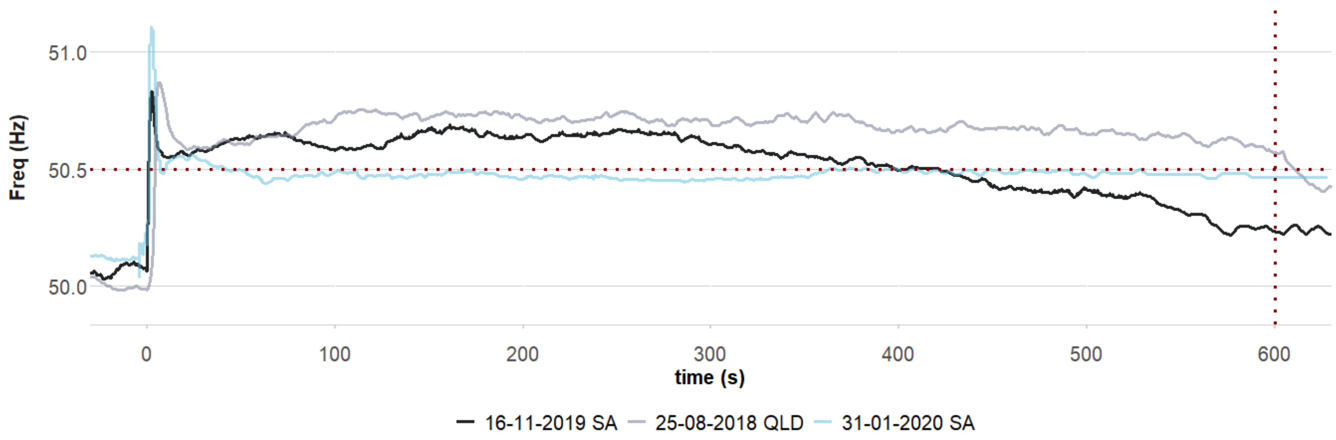
The following observations can be made from these historical examples:

- There is variability in the frequency recovery outcomes over the first 10 minutes. In some cases, frequency naturally settles within the required thresholds within the first 5-40 seconds, while in other cases, frequency does not recover until 400-600 seconds following separation.
  - This variability was also observed in the modelling outcomes. In some cases, the complex interaction of initial contingency size, unit combinations in the region, FCAS and PFR enablement within the island and OFGS/UFLS action means that frequency naturally settles within the required bounds. In other cases, the settling frequency is outside the required bounds, and then does not recover until "external elements" (beyond the automatic responses of units in the island) are enabled.
- In all cases, it took at least eight minutes (480 seconds) and up to 11 minutes (660 seconds) for FCAS constraints to be invoked and for the AGC to be reconfigured for the island, and then further time after that for those constraints to affect unit output to assist with frequency recovery. Until this time, the islanded region was relying on the autonomous response of units in the island.

The frequency trace for the three separation events where the settled frequency was outside necessary thresholds or recovery was not immediate are shown in Figure 30. The following recovery dynamics are observed:

- **16-11-2019 SA (Black)** – frequency peaks at 50.7 Hz before settling at ~50.6 Hz. Frequency recovers below 50.5 Hz after ~400 seconds. This was largely due to a fortuitous over-delivery of delayed FCAS (42 MW enabled, 185 MW delivered).
- **25-08-2018 QLD (Grey)** – frequency peaks at 50.9 Hz and then settles at around 50.6 Hz. There was no contingency lower or regulation lower FCAS dispatched in Queensland at the time of separation. Frequency showed almost no recovery response for the first ten minutes and failed to recover below 50.5 Hz within 10 minutes.
- **31-01-2020 SA (Blue)** – frequency peaks at a zenith of 51.11 Hz, causing the disconnection of 153 MW of generation on the OFGS scheme. Frequency settles just below 50.5 Hz but remains above 50.4 Hz for the next 20 minutes, with almost no recovery response to return back towards 50 Hz. This suggests that if frequency had settled slightly higher, there may not have been additional dynamics to reduce it below 50.5 Hz within 10 minutes.

Figure 30 Frequency in the first 10-minutes following historical non-credible separation events



Based on these historical examples, and a mapping of the control room processes required following a non-credible separation, the model applied for this analysis assumes that the measures required to reconfigure the South Australian island following separation (adjustments to FCAS, AGC, NEMDE, constraints, and re-dispatch) do not take effect in the first 10 minutes, and frequency outcomes in the islanded power system depend only on the automatic responses of resources in the South Australian island. The assumption is that to provide confidence in recovery outcomes, there must be sufficient autonomous responses in the island to achieve that outcome, without manual intervention.

8.1.3 Risks associated with sustained under frequency

There are limits to how long generating units can operate at frequency levels that are outside their normal operating ranges. Most generating units feature protection that will trip the unit if defined thresholds are exceeded for more than a defined duration, to protect the generating unit from damage. This means there is a real risk to the power system that generator tripping leading to cascading failure could occur, if frequency does not recover quickly enough, and remains far outside the normal range for an extended duration. This is particularly problematic during an extended under-frequency event (where generator tripping exacerbates the under-frequency condition), but could also be problematic during an extended over-frequency event if generator tripping is uncoordinated and occurs simultaneously for a large capacity of generation.

The FOS sets a reasonable endeavours standard for stabilising frequency above 49 Hz in two minutes, and above 49.5 Hz in 10 minutes, following a non-credible separation event. This aligns with the continuous operation capabilities of the majority of generating units in South Australia at present, as summarised in Table 35.

Table 35 Frequency Operating Standard compared with generator continuous operation requirements

	FOS requirement for a non-credible separation event	Majority of units (~4 GW) in South Australia at present (Generator Performance Standards)	Some older units (~1.5 GW) in South Australia at present (Generator Performance Standards)	NER minimum requirements for new generator connections (S5.2.5.3)[A]
Containment	47.0-52.0 Hz	47.0-52.0 Hz	47.0-52.0 Hz	47.0-52.0 Hz
Stabilisation (two minutes)	49.0-51.0 Hz	49.0-51.0 Hz	49.0-51.0 Hz	48.0-52.0 Hz
Recovery (10 minutes)	49.5-50.5 Hz	49.5-50.5 Hz	49.5-50.5 Hz for eight minutes only	49.5-50.5 Hz

A. New generator connections are required to maintain continuous operation within 48 – 52 Hz for at least 10 minutes (NER clause S5.2.5.3). Historically, the requirements were less onerous which is reflected in the capabilities of the current generation fleet.

The values in Table 35 were compiled from a review of the GPS of generating units installed in South Australia at present. The review found that:

- For the majority of units in South Australia (~4 GW of registered capacity), their GPS only require units to maintain continuous uninterrupted operation for up to two minutes below 49 Hz and up to 10 minutes below 49.5 Hz.
- For some older units (~1.5 GW of installed capacity), their GPS only require that they maintain continuous operation below 49.5 Hz for up to eight minutes.

AEMO requested information from unit operators to confirm whether there is explicit protection to trip their units if these ranges are exceeded, and requesting advice on whether those protection settings could be safely relaxed to allow the generating units to operate in a stable manner for longer durations without tripping. Survey respondents confirmed that several units have explicit protection elements to disconnect at or just beyond their limits of required continuous operation. For many units without explicit protection, responses indicated that the complex interaction between primary and secondary equipment under extreme frequency conditions made it difficult to predict the timeframe and means by which a generating unit may disconnect. For many units, the continuous operation limits were as notified by the OEM and therefore operators have limited information on limits of capability beyond the ranges specified in their GPS.

Respondents noted that operation outside their required frequency ranges as defined in their GPS could result in:

- Damage to generating units or auxiliary plant.
- Increased maintenance and inspection requirements to maintain reliability.
- Reduced asset lifespan.
- Insurance risk from operating outside of the OEMs specifications.

This review and survey results indicate that:

- It is not currently feasible to verify whether generating units can sustain operation beyond these timelines/thresholds at sufficient scale to extend those parameters in the FOS.
- There is a real risk that generating units may trip if the GPS timelines/thresholds are exceeded, and therefore there are real risks to the power system if frequency is not recovered to the levels required in the time allotted in the FOS following a non-credible separation event.

8.1.4 Acceptance criteria

For this report, AEMO has assumed the acceptance criteria and probabilities outlined in Table 10.

Table 36 Acceptance criteria for frequency stabilisation and recovery studies

	Frequency in first 10 minutes	Likely outcomes	Assumed probability of cascading failure	
			Under-frequency	Over-frequency
Pass	Stabilised within 49-51 Hz within two minutes and recovered to within 49.75-50.25 Hz within 10 minutes and stable	For these cases, there is reasonable confidence that the power system will meet the FOS requirements for frequency stabilisation and recovery.	0%	0%
Risk	Stabilised within 49-51 Hz within two minutes and recovered to within 49.5-50.5 Hz within 10 minutes and stable (RoCoF < 0.01 Hz/s)	FOS requirements have been only marginally met. Modelling uncertainty presents a risk that frequency will not meet the FOS requirements with the potential for generator disconnection.	1%	0.5%
Fail	Not contained within 47-52 Hz, and/or not stabilised within 49-51 Hz within two minutes, and/or not recovered to within 49.5-50.5 Hz within 10 minutes	FOS requirements not met. Possible disconnection of generators, potentially leading to cascading failure.	30%	10%

8.2 Consequences for the power system: Under-frequency risks

Some case studies are outlined below, illustrating example periods that show the dynamics and types of risks that can arise in the stabilisation and recovery timeframes. The case studies in this section focus on under-frequency events. The aggregate responses of synchronous generating units are illustrated, as well as the responses of aggregate BESS. The dynamics of BESS were found to be particularly influential in under-frequency recovery studies. Other types of inverter-based resources are less influential in under-frequency cases, since it was assumed they do not have further headroom available to deliver an under-frequency droop response.

Over-frequency case studies are also shared in Section 8.3. Although over-frequency events are not the focus of this submission, the modelling is considered valid for these cases and included for transparency. During over-frequency events, all types of inverter-based resources are assumed to respond with over-frequency droop if they are generating at the time of the disturbance (and therefore have over-frequency footroom available, in addition to the footroom available on BESS).

The detailed assumptions applied for the PFR of each generating unit type are summarised in Appendix A1.

8.2.1 Case Study 1: Moderate contingency (frequency nadir below 49 Hz)

Figure 31 shows the dynamic response for an example of a moderate contingency where the frequency falls below 49 Hz and UFLS is triggered, and key events are in Table 37. The top left panel shows the frequency outcome in South Australia following the non-credible separation, and the bottom left panel shows the net change in active power from UFLS load tripping and DPV response (with a trip of load shown as positive MW, and a reduction in DPV generation shown as negative MW). The active power responses of BESS and synchronous generating units are shown in the panels on the right. The first 300 seconds (five minutes) is shown in this example, to illustrate the important dynamics occurring in this first phase after the separation. The case is a "fail" outcome, because although frequency recovers above 49 Hz in the first two minutes, it fails to recover above 49.5 Hz in the 10 minutes following the separation (not shown in the figure).

Figure 31 Case study 1: Moderate contingency (nadir below 49 Hz)

	Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	DPV generation (MW)	Imports at Heywood (MW)	Synchronous generator dispatch
Moderate contingency	863	693	6,200	965	306	2

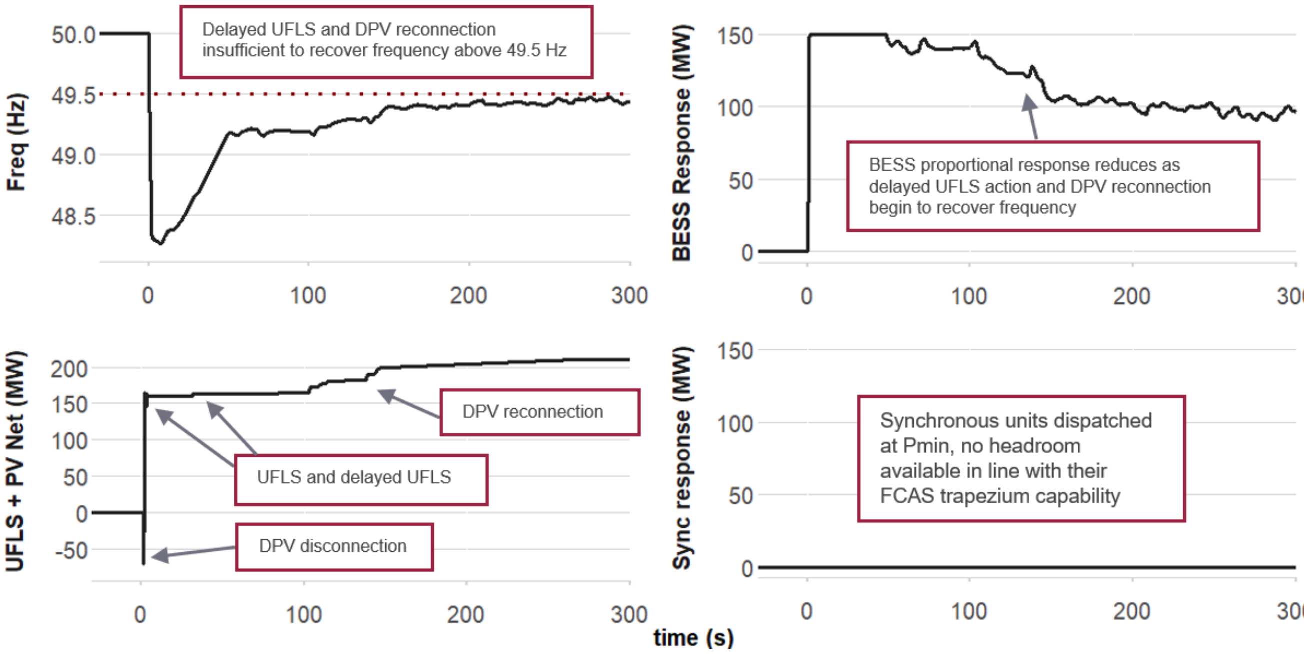


Table 37 Key events in case study 1: Moderate contingency

Time from separation	Event	Notes
0 s	• Separation occurs at Heywood Interconnector	• 306 MW contingency.
1 s	• Frequency falls below 49Hz	• BESS respond on under-frequency droop, delivering maximum possible increase in active power (150 MW). • ~70 MW of DPV disconnects on inverter under-frequency protection settings. • ~230 MW of UFLS is triggered bringing net UFLS + DPV response to ~160 MW.
8 s	• Frequency nadir of 48.3Hz	• UFLS arrests the frequency decline.
8-50 s	• Frequency recovers slowly	• Net response of batteries, UFLS and DPV slightly larger than initial contingency recovering frequency. • Battery response is at its limit and does not reduce until frequency > 49.1 Hz driving a sustained response for this period.
31 s	• Delayed UFLS block triggers	• Net load on delayed UFLS block is less than 1MW due to significant DPV generation, so this has minimal impact to assist frequency recovery.
48 s	• BESS response starts to reduce on droop	• As frequency recovers above 49.1 Hz, the BESS response reduces on droop (top right panel). • Frequency recovery stalls at ~49.2 Hz.
103-360 s	• DPV reconnection	• Frequency has recovered above 49 Hz for more than 60 seconds, allowing some DPV that disconnected to reconnect. • Causes a small frequency increase which leads to more reduction of battery response on droop.
6 min to 10 min	• No further dynamics	• Once all the DPV has reconnected, are no further power system dynamics to drive a further recovery in frequency.
10 min	• Fail outcome (not shown)	• The frequency fails to recover above 49.5 Hz in the 10 minutes following the separation.

This shows an example of a case where the trip of UFLS blocks does not lead to a settling frequency within the required thresholds, and the remaining dynamics in the island are not sufficient to recover frequency. The interaction with the withdrawal of the BESS droop response is elaborated on further in Section 8.4.2.

Approximately 80% of the fail/risk cases identified in studies have a frequency nadir below 49 Hz, and show dynamics similar to this case study.

8.2.2 Case Study 2: Mild contingency (frequency nadir above 49 Hz)

Figure 32 shows a case study with a relatively mild initial contingency (nadir above 49 Hz), and Table 38 lists key events.

Figure 32 Case Study 2: Mild contingency (nadir above 49 Hz)

	Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	DPV generation (MW)	Imports at Heywood (MW)	Synchronous generator dispatch
Mild contingency	1,704	1,450	10,661	0	130	2

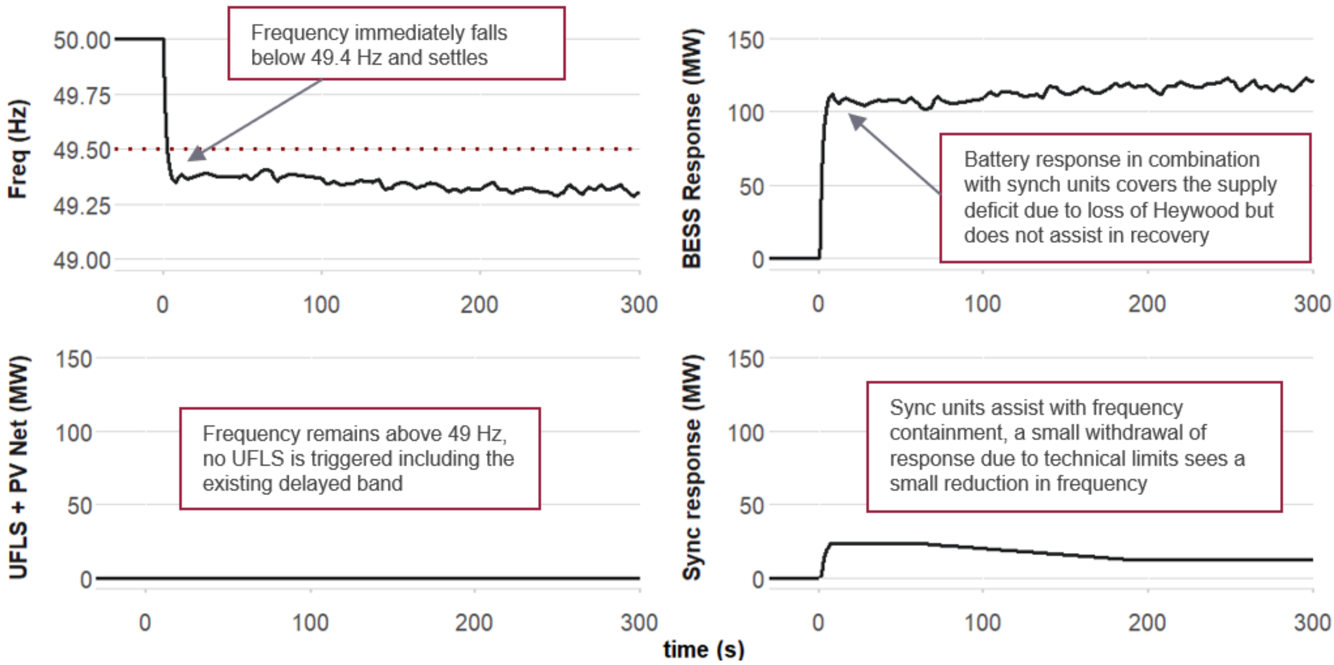


Table 38 Key events in case study 2: Mild contingency

Time from separation	Event	Notes
0 s	• Separation occurs at Heywood Interconnector	• 130 MW contingency • BESS increase output to ~110 MW • Sync units increase output by ~20 MW, covers supply shortfall
8 s	• Initial Frequency nadir	• Frequency falls to 49.35 Hz and settles
60-190 s	• Small reduction in synchronous response	• Sync units reduce output slightly due to technical limitations • Frequency reduces by 0.05 Hz • BESS increase output to again arrest frequency at 49.3 Hz
3 min to 10 min	• No further dynamics	• No further dynamics occur to assist frequency recovery
10 min	• Fail outcome (not shown)	• Frequency fails to recover above 49.5 Hz in the 10 minutes following the contingency.

In this case study, frequency falls below 49.5 Hz in the original contingency, but never falls below 49 Hz and therefore does not trigger UFLS, DPV disconnection, or the delayed UFLS band. There are no further dynamics until constraints are enabled for the South Australia island (up to 10-15 minutes) so frequency remains below 49.5 Hz.

The withdrawal of synchronous response over time in line with FCAS trapezium availability, as seen in this case study, often results in poorer frequency recovery outcomes in cases with synchronous response available.

Approximately 20% of the fail/risk cases identified in studies have a frequency nadir above 49 Hz, and show dynamics similar to this case study.

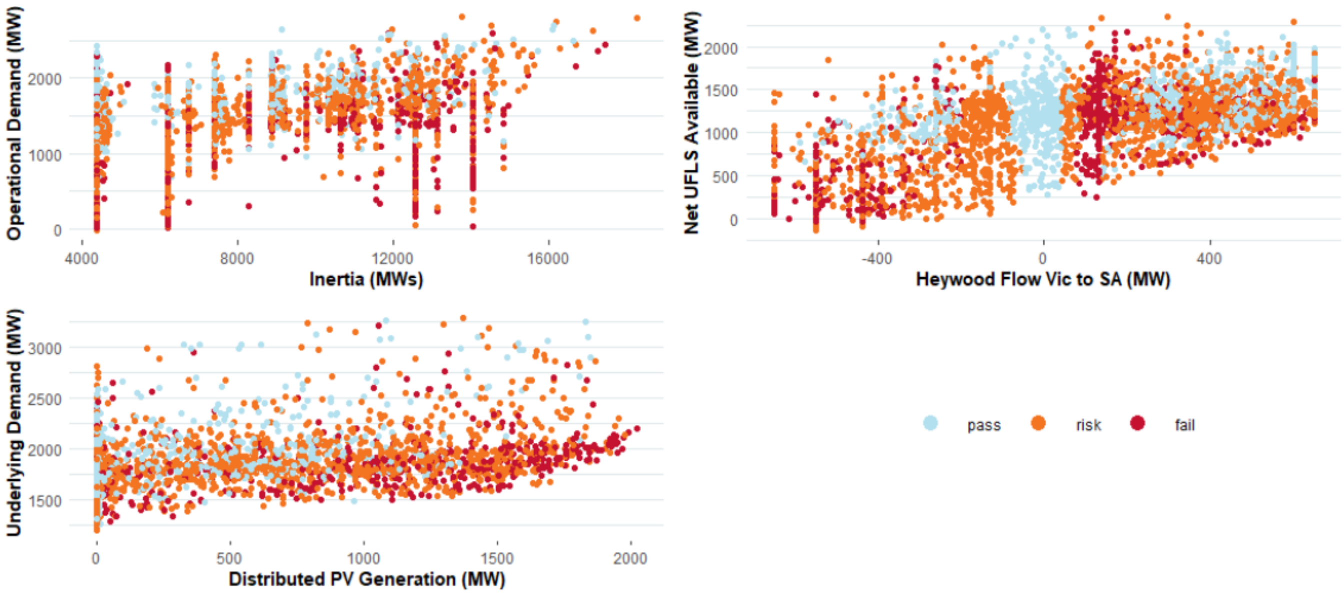
8.2.3 Predicting frequency recovery issues from pre-event system conditions

In general, frequency recovery risk outcomes show little correlation to any discernible pre-event variables, as demonstrated in Figure 33. These figures show pass outcomes in blue, risk outcomes in orange, and fail outcomes in red. They are plotted as a scatter chart against a selection of different variables, to identify possible trends against power system inertia, demand, net UFLS available, distributed PV generation, Heywood Interconnector flows, or any other discernible factors. The following trends can be seen:

- Pass cases are observed for all cases with Heywood Interconnector flows below ~50 MW (due to the very small initial contingency size, such that the frequency nadir does not fall far below 49.5 Hz).
- There is a slight trend towards more fail cases at high levels of DPV generation and low levels of operational demand (although some pass cases are observed even with DPV generation above 1,500 MW).

No other significant trends were observable; each outcome (pass/risk/fail) was found to be almost equally likely at any level of these various variables. This indicates that pre-event conditions are not a good indicator of frequency recovery outcomes.

Figure 33 Pre-event conditions as a predictor of frequency recovery outcomes



The studies suggest that frequency recovery outcomes in any particular case depend on the subtle nuances of interacting factors, such as whether the original contingency size matches UFLS load blocks exactly, or is just enough (or not quite large enough) to trip the next block.

This makes it difficult to predict the likelihood of a frequency recovery issue based on pre-event conditions. Instead, frequency recovery issues must be considered equally likely in any period, unless interconnector flows are very low. Therefore, to ensure a frequency recovery response is available when needed, management measures will likely need to be enabled at all times.

8.3 Consequences for the power system: Over-frequency risks

This report focuses on non-credible separation events that result in under-frequency in South Australia. However, analysis of frequency recovery has also been conducted for periods resulting in over-frequency in South Australia, and is summarised here for completeness. Similar challenges are observed in over-frequency separation events, and can be addressed via implementation of similar management measures as those applied to address under-frequency events.

Over-frequency scenarios have been assumed to have a lower risk of cascading failure, since tripping of generating units will generally assist in correcting an over-frequency condition. However, uncoordinated tripping of generating units in response to an extended over-frequency condition outside of required thresholds could lead to excessive tripping and an under-frequency scenario. These scenarios therefore have some possibility of cascading failure, and should be avoided if low-cost measures can be designed to allow frequency recovery in the required timeframes.

These studies include a representation of:

- The South Australia Over-Frequency Generation Shedding (OFGS) scheme.
- DPV over-frequency tripping and DPV controlled over-frequency curtailment responses[50] (calibrated based on field measurements and bench testing of DPV inverters[51]).
- The proportional over-frequency droop responses from BESS, other types of inverter-based resources, and synchronous generators (required via mandatory primary frequency response[52]).

8.3.1 Case studies illustrating periods at risk

Figure 34 compares three case studies with varied pre-event conditions, illustrating over-frequency scenarios. In all cases frequency failed to recover to the necessary levels within 10 minutes of the initial event. Details of these example scenarios are as follows:

- **Black scenario** – following a relatively mild contingency (260 MW) the frequency rises to a zenith of 50.9 Hz and settles at 50.7 Hz. No OFGS activation occurs as the frequency does not exceed 51 Hz. DPV output reduces by 110 MW initially, assisting with frequency containment, followed by some reconnection driving frequency up and subsequent disconnection as the frequency again exceeds the disconnection threshold. Frequency fails to reduce below 50.5 Hz within 10 minutes.
- **Grey scenario** – a moderate contingency (373 MW) causes frequency to rise to a zenith of 51.1 Hz, causing the disconnection of 94 MW of generation from OFGS action and 134 MW of reduction in DPV output. Frequency settles just above 50.5 Hz before DPV reconnection commences, driving frequency up again. The BESS respond on droop by increasing consumption, limiting the frequency rise. Frequency settles at 50.7 Hz.

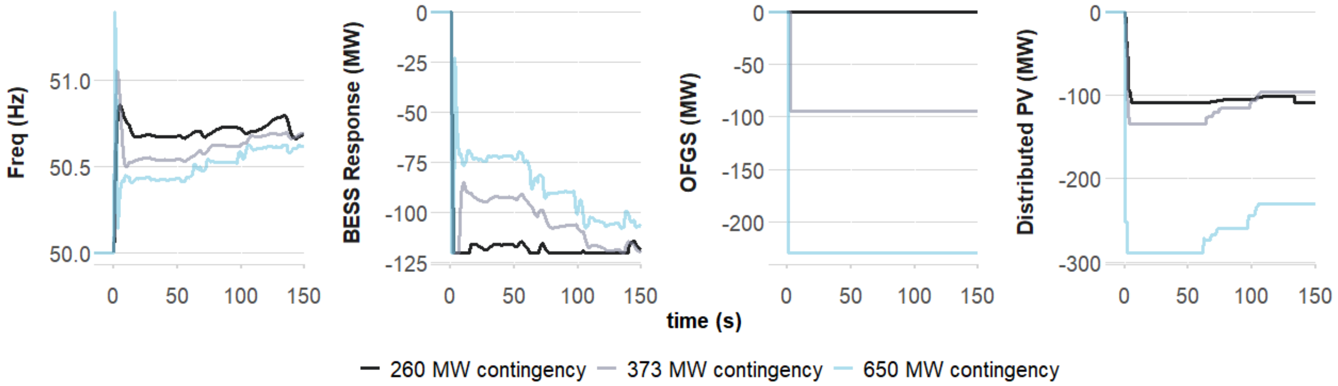
[50] Inverters connected under the 2015 and 2020 AS/NZS4777.2 Australian Standards are required to deliver a controlled over-frequency curtailment response when frequency exceeds 50.25Hz.

[51] AEMO (May 2021) *Behaviour of distributed resources during power system disturbances*, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[52] AEMO, *Primary Frequency Response*, https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response#:~:text=AEMO%20must%20consult%20on%20and,PFRR%20for%20individual%20generating%20plant.

- **Blue scenario** – a large contingency drives frequency up to a zenith of 51.4 Hz, causing 229 MW of generation to disconnect due to OFGS action and a reduction of 290 MW of DPV. Frequency settles initially at 50.4 Hz but is then driven up due to significant quantities of DPV reconnecting. BESS increase consumption, limiting the frequency rise. Frequency settles at 50.6 Hz.

Figure 34 Case studies: Examples of over-frequency fail scenarios



As for under-frequency events, the recovery outcomes in over-frequency scenarios depend on the subtle nuances and interactions in the event, and fail scenarios can occur for any combination of pre-event conditions (except in scenarios where exports at the point of separation are below 50 MW and the zenith remains below 50.5 Hz).

8.3.2 DPV reconnection

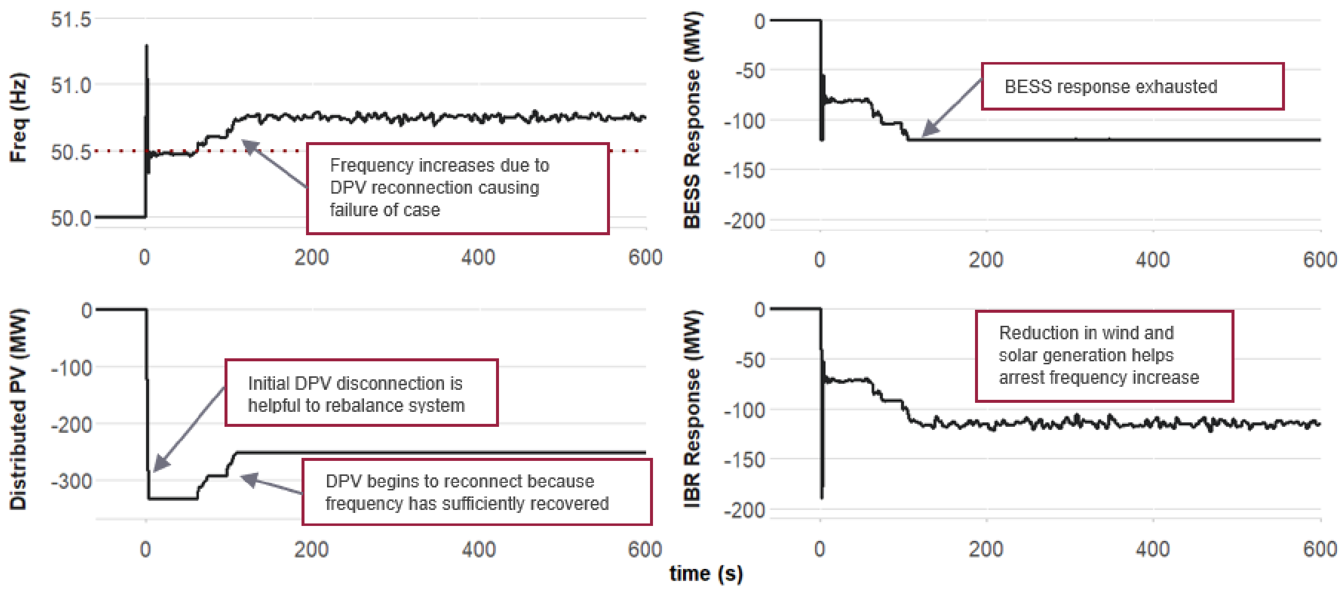
The disconnection and curtailment response of DPV assists successful frequency containment for over-frequency events in high DPV periods. However, subsequent DPV reconnection can then contribute to poorer recovery outcomes.

In the 10 minutes following a separation, as frequency recovers, DPV that has disconnected will begin to reconnect (when frequency recovers below the frequency at which they disconnected for more than 60-100 seconds) and reduce the controlled curtailment response (when frequency recovers below 50.15 Hz for more than 60 seconds). This can contribute to somewhat poorer frequency recovery outcomes for over-frequency events occurring in daytime periods. These dynamics have been included in the model.

For example, in the case study shown in Figure 35 (a case with high levels of DPV operating), frequency initially settles at just below 50.5 Hz. DPV that disconnected due to the initial frequency event begins to reconnect at approximately 60 seconds (bottom left panel), pushing frequency up to 50.75 Hz. The IBR on droop control responds by increasing BESS consumption and reducing wind and solar generation, which limits the frequency increase. However, the available BESS response is exhausted, and is not sufficient to prevent frequency from moving outside the required range.

Figure 35 Case study: impact of DPV reconnection on frequency recovery following over-frequency event

	Operational demand (MW)	Inertia (MWs)	DPV generation (MW)	Exports at Heywood (MW)	Synchronous generator dispatch
Droop withdrawal example	276	4,400	1,461	520	0



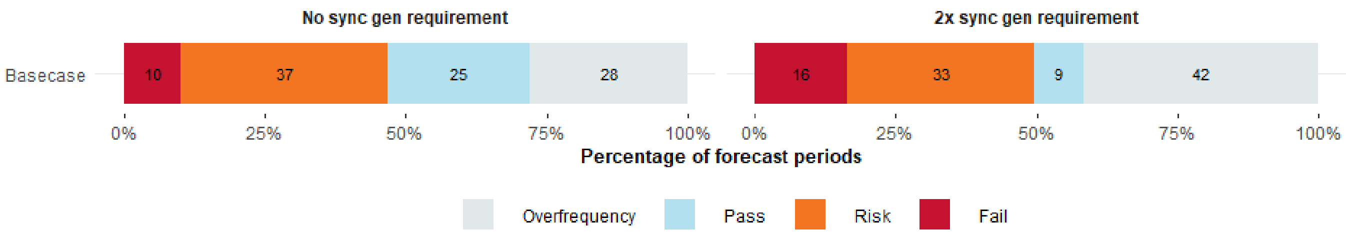
8.4 Percentage of time at risk

8.4.1 Under-frequency risks

Figure 4 summarises the outcomes for frequency recovery following a double-circuit separation at the Heywood Interconnector, for the two scenarios of forecast dispatch patterns in 2022-23 and 2023-24.

The results indicate that frequency recovery fails to meet the FOS requirements following an under-frequency event in 10-16% of all periods. A further 33-37% of periods are identified as risk periods where frequency has only marginally met the FOS requirements. This indicates that approximately 50% of the time, there is a risk of not meeting the frequency recovery requirements in an under-frequency event.

Figure 36 Frequency recovery – under-frequency (2022-23 and 2023-24)



Sensitivities – Under-frequency risks

A number of sensitivities to the base case were explored, to understand how power system recovery dynamics could vary depending on system conditions.

Net demand variation

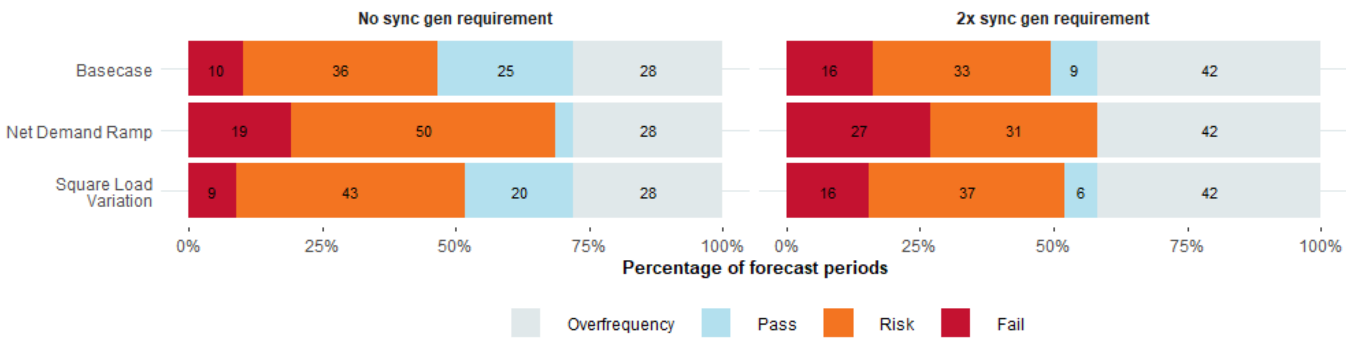
Net demand refers to the total underlying customer demand, net of variable generation sources including DPV and semi-scheduled generation. The net demand captures the natural variability in demand itself, as well as variability in both small- and large-scale wind and solar generation. In the first 10 minutes following a non-credible separation event, there may not be any regulation FCAS enabled in the South Australia island, and frequency dynamics will depend only on the autonomous responses of components in the South Australia island.

A sensitivity analysis was conducted to explore how net demand variability could affect frequency recovery dynamics. Two net load variation sensitivities were applied to the model:

- **Net demand ramp** – a ramped increase in net demand over 10 minutes consistent with the 95th percentile absolute net demand ramp experienced in South Australia over the 2020-21 period. This represents a relatively extreme 'worst case' possibility (it is possible but relatively unlikely that the 95th percentile net demand ramp would occur in the 10 minutes following a non-credible separation event).
- **Square load variation** – a representation of typical industrial load variation experienced in South Australia, modelled as a square load variation of 12 MW at a rate of 7 cycles per 10 minutes.

The results are presented in Figure 37. The sensitivity studies show that an extreme ramp in net demand significantly increases the proportion of cases that fail, but the square load variation has minimal impact on recovery outcomes.

Figure 37 Frequency recovery with net demand variation sensitivities



Net demand variation during the first 10 minutes following a separation event could have a helpful or unhelpful impact on frequency recovery depending on the direction.

8.4.2 Impact of proportional droop response

Proportional droop response is an important contributor to arresting and stabilising a severe frequency decline immediately following a separation event. However, the studies showed in some cases that an increased amount of fast responding proportional response could result in poorer frequency *recovery* outcomes.

Figure 38 shows the base case results with an increasing quantity of available proportional response modelled in line with typical battery droop and timing capabilities. The results indicate that the frequency recovery risk increases with some additional headroom (up to 400 MW) primarily due to more cases resulting in the frequency settling below 49.5 Hz[53]. As the quantity increases further, the risk reduces as the amount of proportional response is sufficient to settle frequency above 49.5 Hz in most cases. In the near future it is expected that additional units will be commissioned in South Australia that will likely increase the quantity of BESS available in many periods.

Figure 38 Impact of increasing fast acting proportional response headroom on frequency recovery

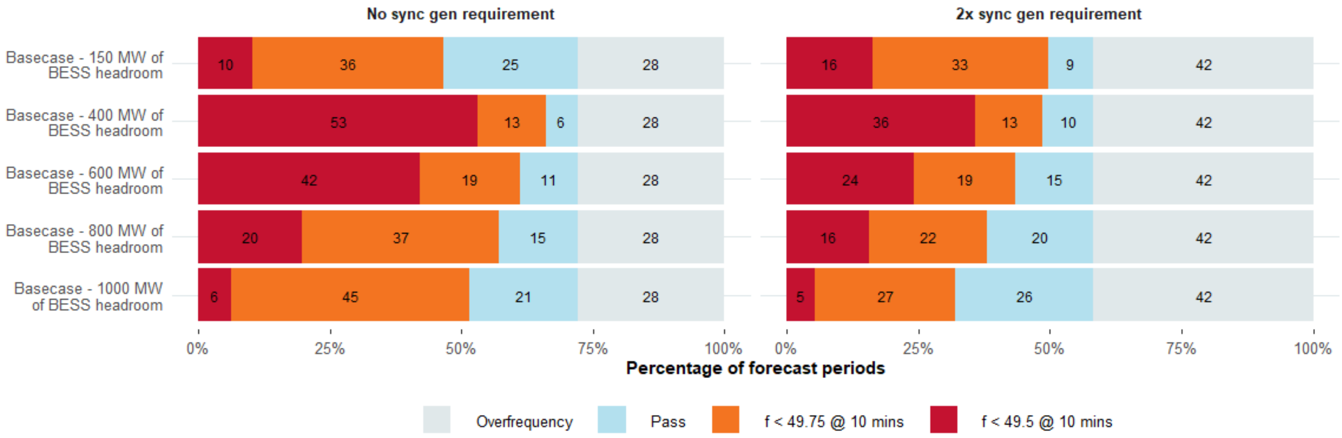
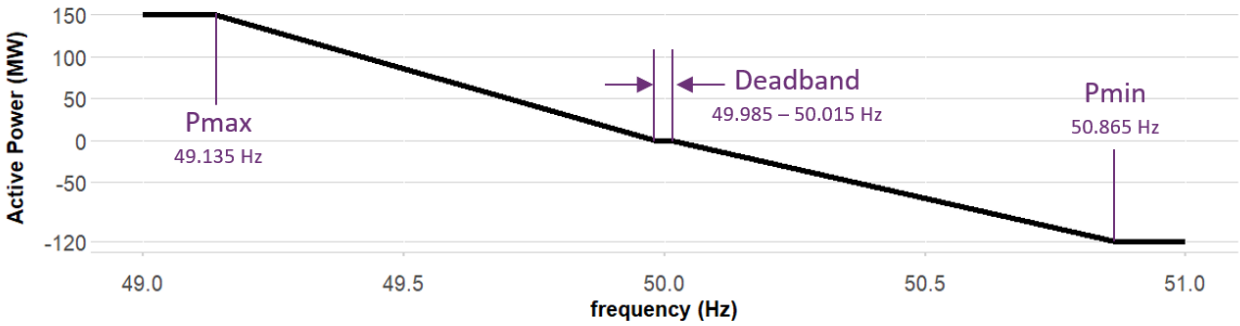


Figure 39 illustrates the proportional droop response assumed to be delivered by BESS in these studies (1.7% droop function, responding with a delay of 200 ms, and deadband of ±0.015 Hz). Following an under-frequency event, to recover frequency, an increase in net active power is required. As services start to respond to deliver this increase, and frequency starts to rise back towards 50 Hz, the proportional droop providers will progressively deliver less active power injection, as they move down their droop function back towards 50 Hz.

Figure 39 Proportional droop response assumed for BESS in these studies



These dynamics can be observed in the example in Figure 40, where:

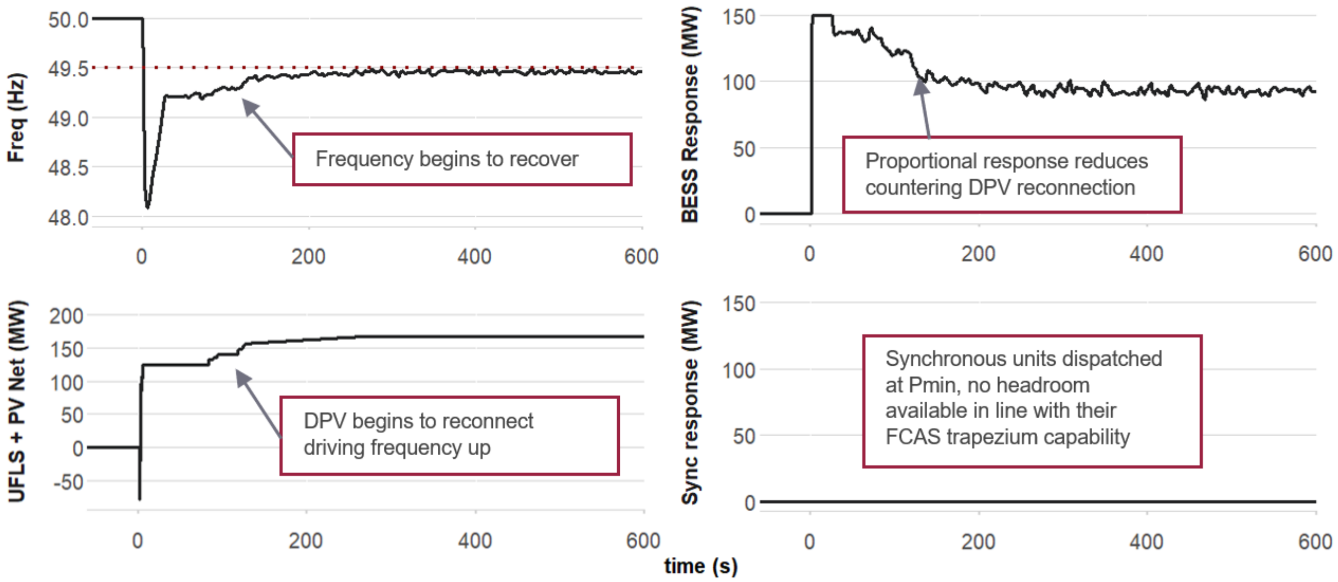
- DPV begins to reconnect approximately 60 seconds after the separation (bottom left panel).
- The frequency then begins to recover (top left panel).
- In response to the frequency recovery, the generation from BESS (and other proportional droop providers) begins to reduce as they move down their droop function.

[53] The frequency nadir improves with increased headroom, however, the proportion of cases that settle below 49.5 Hz following initial frequency response increases

This means that proportional droop response will, to some degree, counter the efforts of other elements acting to recover frequency. Consequently, while fast acting proportional droop response assists in the initial frequency containment, it does not address (and may exacerbate) issues related to frequency recovery.

Figure 40 Case study 3: Example of withdrawal of droop response as frequency recovers

	Operational demand (MW)	UFLS load (MW)	Inertia (MWs)	DPV generation (MW)	Imports at Heywood (MW)	Synchronous generator dispatch
Droop withdrawal example	816	581	6,200	1,075	260	2



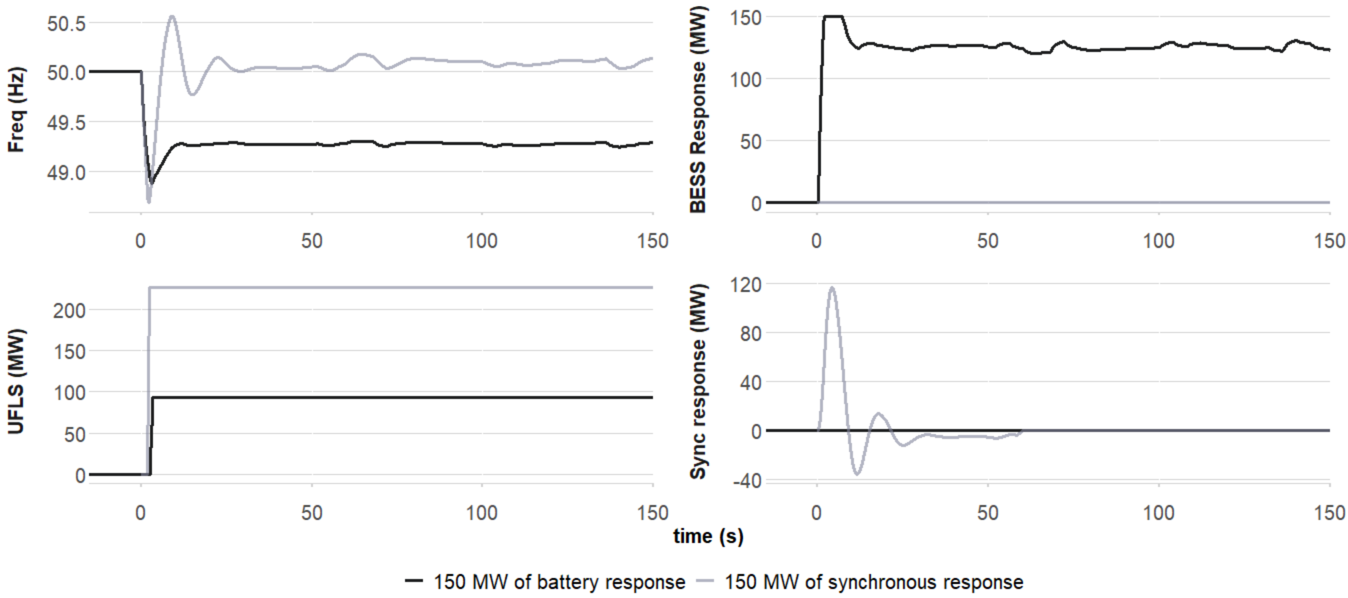
Fast acting proportional droop response (such as that delivered by inverter-based resources) can be more problematic for frequency recovery than slower proportional responses delivered by synchronous units. The fast nature acts in timeframes that are similar to or faster than UFLS, preventing UFLS block tripping in the initial arrest of frequency. While avoiding customer load shedding is a positive benefit, this means the sustained switched response from UFLS has been replaced with proportional droop response, which will withdraw as frequency starts to recover.

The case study in Figure 41 illustrates this point by comparing the frequency outcome of a case with 150 MW of proportional BESS response enabled (black) versus 150 MW of proportional synchronous response enabled (grey). The faster BESS response in the black scenario reduces the amount of UFLS tripped, and frequency recovery stalls at 49.3 Hz. In contrast, in the grey scenario with the slower synchronous proportional response a larger amount of load is disconnected by UFLS, and frequency recovers close to 50 Hz. This effect is more prevalent in higher RoCoF conditions.

These effects means that as the power system transitions to a larger proportion of IBR with fast proportional droop responses, this assists with improving frequency containment, but additional management measures may be required to improve frequency recovery dynamics.

A combination of proportional and switched controllers as described in the MASS issues paper[54] (allowable for contingency FCAS providers[55]) helps mitigate the frequency recovery challenges from proportional only providers. The switched component acts to provide a sustained response similar to the disconnection of load via UFLS, while the proportional component provides variable control. However, under present FCAS frameworks, there is no way to guarantee any particular amount of switched or proportional response available in a South Australian island following a non-credible separation event.

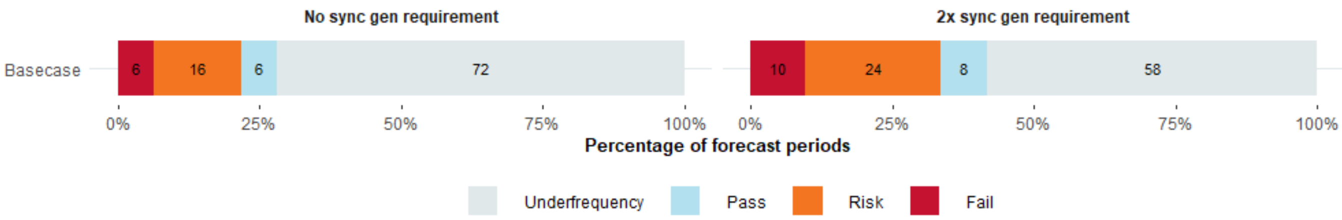
Figure 41 Case study: comparison of synchronous and battery response (higher RoCoF)



8.4.3 Over-frequency risks

Figure 42 summarises the results for over-frequency events, indicating that frequency recovery is in the fail category following an over-frequency event in 6-10% of all periods with a further 16-24% of periods in the risk category.

Figure 42 Frequency recovery – over-frequency (2022-23 and 2023-24)



Modelling indicated that over-frequency recovery was impacted in a similar manner to under-frequency events by proportional response and variation of net demand.

[54] AEMO (May 2022) *Market Ancillary Service Specification Consultation – Issues Paper* – Section 5.3, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/amendment-of-the-mass/mass-issues-paper.pdf?la=en.

[55] AEMO (December 2021) Market Ancillary Service Specification v7.0, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/primary-freq-resp-norm-op-conditions/market-ancillary-services-specification-v70.pdf?la=en.

8.5 Estimate of unserved energy

Table 16 provides an estimate of the amount of USE and annual costs associated with the likelihood of a black system event due to poor frequency stabilisation and recovery.

The likelihood of a non-credible separation, and the USE associated with each black system event, are estimated as summarised in Appendix A4, with possible variability in these estimated values giving rise to the ranges indicated in Table 16.

Table 39 USE estimates associated with frequency recovery - Separation at Heywood Interconnector

	Under-frequency events			Over-frequency events		
	USE (MWh/year)	Annual cost ($ million/year)		USE (MWh/year)	Annual cost ($ million/year)	
		Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement (cost-reflective bidding profiles)	111-494	$5-$21	$10-$43	20-90	$1-$4	$2-$8
Minimum 2 synchronous unit requirement (historical bidding profiles)	163-725	$7-$31	$14-$63	34-149	$1-$6	$3-$13

9 Management options for frequency stabilisation and recovery

This section outlines a series of options that have been explored to improve frequency stabilisation and recovery outcomes for South Australian separation events.

9.1 Option 1: Delayed UFLS

9.1.1 Description

At present, there is a single delayed UFLS band that will trip if frequency falls below 49 Hz and remains below 49.5 Hz after 30 seconds. This delayed UFLS block is intended to assist in frequency recovery.

Based on the frequency recovery studies conducted for this submission, AEMO has recommended that SAPN expand the delayed UFLS scheme in South Australia, increasing the total amount of load in the delayed UFLS scheme up to an average of 120 MW.

SAPN has advised AEMO that there are sufficient modern electronic relays within its current fleet capable of operating different frequency protection elements at different time settings. This allows an existing UFLS feeder to trip on either its existing trip settings (as part of the UFLS designed for containment) or delayed trip settings (to assist with frequency recovery), whichever occurs first. This facilitates an increase in the amount of load in the delayed UFLS scheme, without that load needing to be removed from the original UFLS scheme. AEMO's studies indicate that in most periods, there will be UFLS load still available following the initial frequency arrest that could be used for delayed UFLS in this manner.

9.1.2 Expected power system security outcomes

Applying datasets supplied by SAPN, the amount of net load available behind modern electronic UFLS relays capable of dual settings was estimated for each half-hour of the forecast period. Across the forecast period, the total delayed UFLS load available in each period ranged between -83 MW and 295 MW, with an average of 116 MW[56]. AEMO's studies assumed that all of this load was added to the delayed UFLS scheme, divided into 15 blocks, with delays beginning at 45 seconds and incrementally increasing by 15 seconds with each block.

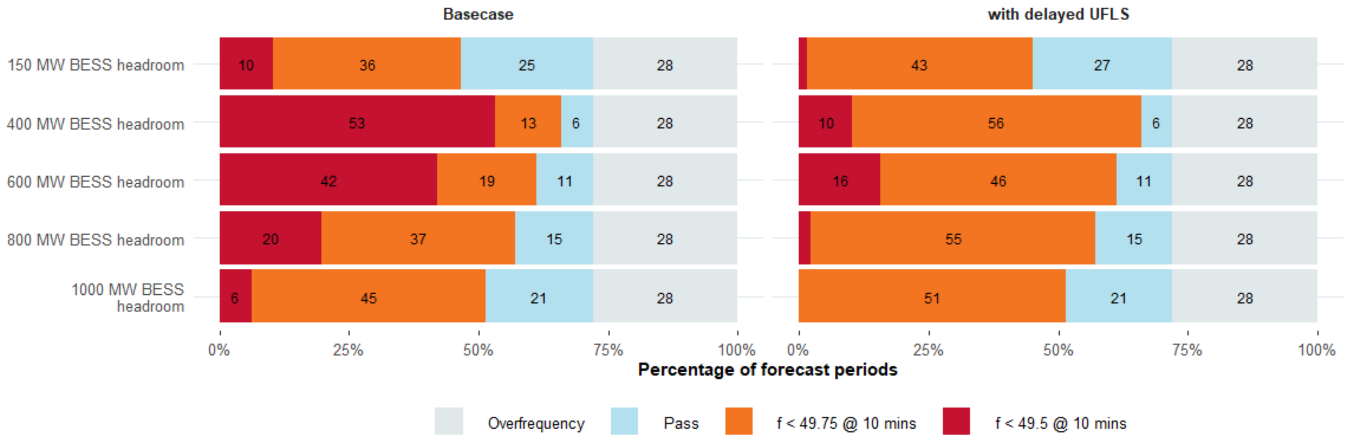
Figure 43 compares the base case results (left column) with the results following implementation of the expanded delayed UFLS (right column) for varying levels of fast acting proportional response headroom in line with the results presented in Section 8.4.2. Only the no synchronous generator requirement dispatch scenario results are shown, but similar outcomes were observed for the 2 x synchronous generator requirement scenario.

The results show significant improvement over the base case for all levels of BESS headroom, however the impact of delayed UFLS is lessened at higher levels. This is due to more MW change being required for the same shift in frequency as proportional response increases. This indicates that an expansion of the delayed UFLS

[56] Following the implementation of dynamic arming of UFLS, periods with negative UFLS load should be eliminated. SAPN is rolling out dynamic arming during 2023 and 2024. This has not been accounted for in this analysis, but should improve findings further.

scheme is highly effective in reducing the incidence of the highest risk under-frequency cases, but additional measures may be required to manage periods with high availability of proportional response in future.

Figure 43 Impact of delayed UFLS on frequency recovery outcomes (2022-23 and 2023-24) with varying BESS headroom, no synchronous generator requirement



As involuntary load shedding is considered a last resort measure, the delayed UFLS settings proposed are designed to reduce the number of fail cases (return frequency to above 49 Hz in two minutes and above 49.5 Hz within 10 minutes), but to minimise load shedding have not been designed to manage “risk” cases (shown in orange in Figure 43).

9.1.3 Estimated benefits

Table 40 summarises an estimate of the benefits of expanding delayed UFLS in South Australia as proposed. The approach and assumptions applied are identical to those outlined in Section 8.5 and Appendix A4.

Table 40 Benefits of expanding delayed UFLS (2022-23 and 2023-24)

	Reduction in USE **(MWh/year)**	Estimated benefits **($mil/year)**	
		Standard VCR	**2 x VCR**
No minimum synchronous unit requirement (cost-reflective bidding profiles)	68-300	$3-$13	$6-$26
Minimum 2 synchronous unit requirement (historical bidding profiles)	135-598	$6-$26	$12-$52

9.1.4 Additional costs

SAPN has indicated that the proposed delayed UFLS settings will be implemented at the same time as dynamic arming of UFLS relays, with minimal additional cost.

9.1.5 Recommendation

AEMO has recommended to SAPN that implementation of this option proceed. This is assumed to have been implemented when considering additional options.

9.2 Option 2: Modification of existing UFLS bands

9.2.1 Description

A reduction in the number of UFLS frequency setting bands, while keeping the total load quantity the same, results in larger individual trip blocks. Less granular, larger blocks might increase the likelihood of tripping more UFLS and hence could lead to a reduction in cases experiencing frequency recovery stalling below 49.5 Hz. This needs to be balanced against the risks of over-tripping UFLS leading to frequency overshoot.

Figure 44 illustrates the effects of amalgamating UFLS bands. The black scenario shows the present arrangement of UFLS bands in South Australia, the blue case shows a counterfactual with these split into more bands, and the grey case shows another counterfactual with these amalgamated into fewer bands. In this case study, frequency recovery is improved in the grey scenario (with fewer UFLS bands). The difference in frequency recovery outcomes is due to the granularity of the block sizes, meaning that the last block tripped differs in size.

Figure 44 Case study: larger UFLS blocks can improve frequency recovery

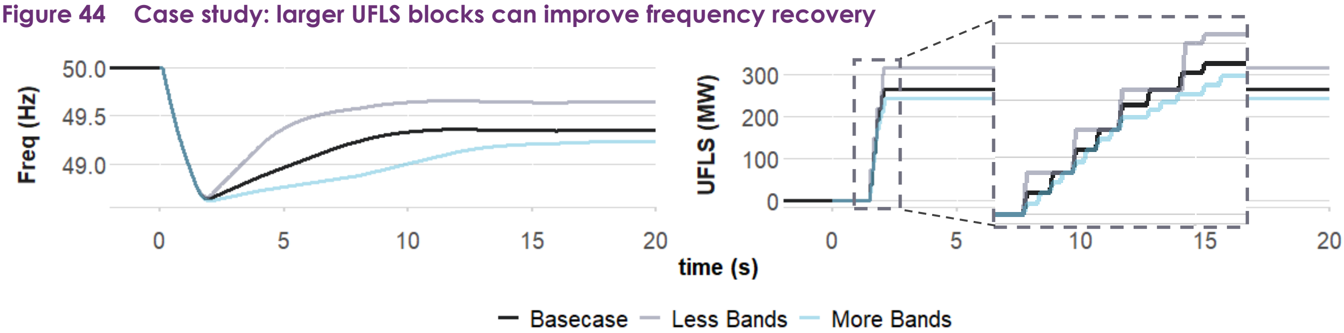
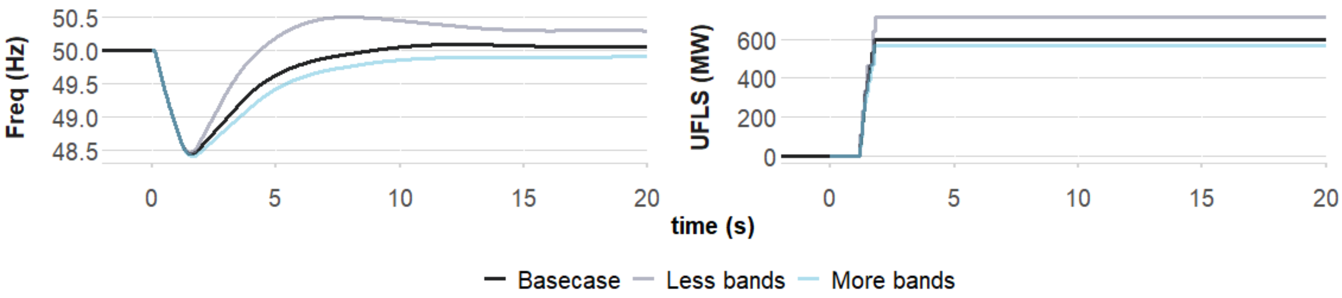


Figure 45 presents outcomes for the same UFLS band arrangements, but with a different contingency event. In this case, the grey scenario (with fewer UFLS bands) results in over-tripping of UFLS and frequency overshoot.

Figure 45 Case study: larger UFLS blocks increase risk of frequency overshoot



9.2.2 Expected power system security outcomes

There are currently 29 unique frequency and time delay combination bands in the short delay (<1 second) South Australian UFLS scheme. To test the impact of reducing the number of bands, a case was made where seven bands were aggregated into the adjacent band to reduce the total to 22 unique combination bands. To test more bands, 13 of the existing bands were split, with the load distributed to extra bands in between the existing frequency settings, making a total of 42 unique bands. Several bands remain unchanged as they represent specific or sensitive loads unsuitable for changing.

The results of the study in Figure 46 show that more UFLS bands results in slightly worse frequency recovery outcomes, while fewer bands results in a slight improvement. In many cases, however, the frequency outcomes are nearly identical regardless of the number of UFLS bands as the same amount of load disconnection from UFLS occurs.

Figure 46 Impact of varying number of UFLS blocks on frequency outcomes

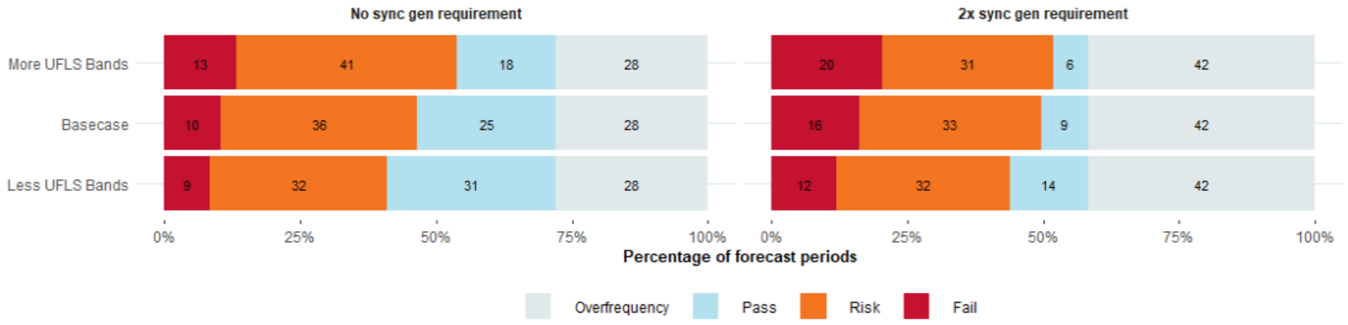
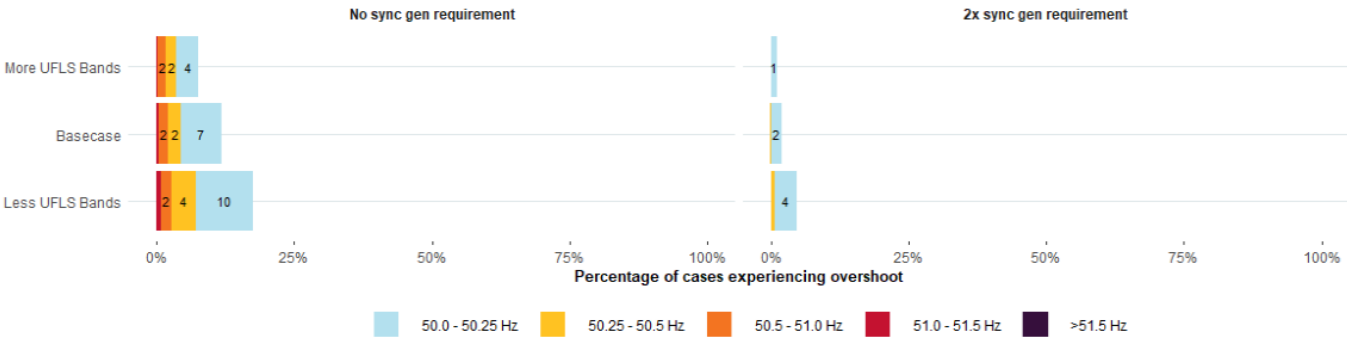


Figure 47 demonstrates the impact of varying UFLS block size on the frequency overshoot observed following UFLS action and frequency recovery. As the number of bands are reduced, the incidence of overshoot increases.

Figure 47 Impact of varying number of UFLS blocks on frequency overshoot



9.2.3 Recommendation

The results indicate that amalgamating UFLS bands might somewhat improve frequency recovery outcomes, but it also results in an increased risk of over-tripping UFLS load, leading to frequency overshoot. AEMO does not recommend pursuing this option further. UFLS band sizes will be considered as one of many elements to optimise as part of future review of the South Australian UFLS scheme.

9.3 Option 3: Delayed OFGS

9.3.1 Description

There is currently a coordinated OFGS scheme in South Australia. Staged trip settings are applied to many generating units in South Australia, to provide a coordinated over-frequency response to extreme frequency excursions.

To help manage frequency recovery following an over-frequency event, where frequency is above 50.5 Hz for an extended period of time, AEMO has proposed the addition of delayed settings to the OFGS scheme in South Australia. This would reduce frequency following an extended period of over-frequency in an orderly and more predictable manner. This mechanism also manages cases where a severe under-frequency event leads to significant frequency overshoot, that can result in a settled frequency above 50.5 Hz.

As part of a number of recommendations in AEMO's recent review of the South Australian OFGS scheme, AEMO has made recommendations to ElectraNet to implement four delayed OFGS bands – two specifically addressing the stabilisation timeframe (recovery to 51 Hz within two minutes) and two addressing the recovery timeframe (recovery to 50.5 Hz within 10 minutes). The amount of OFGS required in each band was indicated based on a proportion of total wind generation in South Australia, to account for variation in availability.

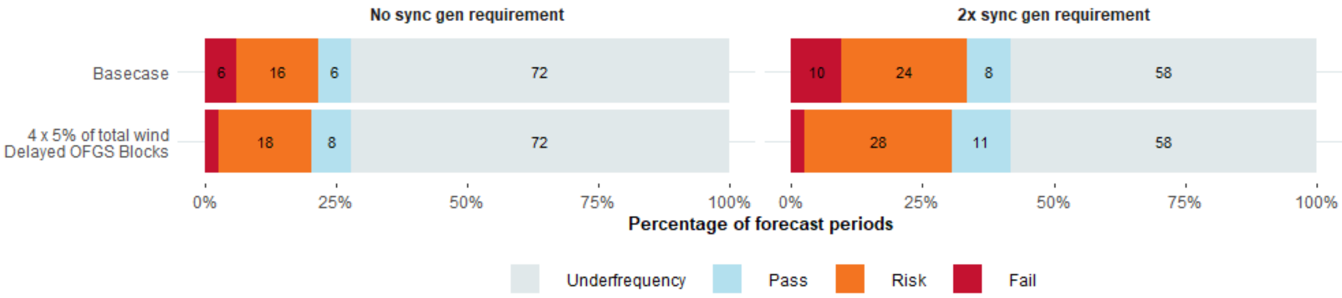
Frequency recovery outcomes for over-frequency events will be dependent on the dispatch of the selected delayed OFGS generator/s in South Australia. The variability in dispatch modelled in these studies was based on ISP forecasts.

9.3.2 Expected power system security outcomes

Delayed OFGS was modelled to include two blocks tripping for frequency exceeding 51 Hz with delay time below two minutes and two blocks tripping above 50.5 Hz with delay time below 10 minutes. In this modelling, each block is comprised of 5% of total South Australian wind generation (~120 MW capacity) in each period at 15-second increments in delay time. Actual implementation of the delayed OFGS will depend on capability from feeder and circuit breaker configurations at wind farm sites.

Figure 48 shows that the addition of four delayed OFGS blocks reduces the incidence of fail cases from 6-11% down to 2-3%. Additional blocks of delayed OFGS were tested with diminishing levels of improvement with more generation added.

Figure 48 Impact of delayed OFGS on frequency recovery outcomes over 2022-23 and 2023-24



As generator shedding is a last resort emergency mechanism for over-frequency conditions, the proposed settings have been designed to reduce the number of fail cases, and additional frequency management options will be required for reduction of risk cases.

9.3.3 Estimated benefits

Table 41 summarises an estimate of the benefits of implementing delayed OFGS in South Australia as proposed. The approach and assumptions applied are identical to those outlined in Section 8.5 and Appendix A4.

Table 41 Benefits of implementing delayed OFGS (2022-23 and 2023-24)

	Reduction in USE (MWh/year)	Estimated benefits ($mil/year)	
		Standard VCR	2 x VCR
No minimum synchronous unit requirement (cost-reflective bidding profiles)	9-39	$0-$2	$1-$3
Minimum 2 synchronous unit requirement (historical bidding profiles)	23-104	$1-$4	$2-$9

9.3.4 Additional costs

This action has been recommended for implementation under the existing OFGS framework.

9.3.5 Recommendation

AEMO has recommended to ElectraNet that implementation of this option proceed. This is an action that is assumed to have been implemented when considering additional options.

9.4 Option 4: Frequency recovery mode

9.4.1 Description

As described in Section 8.4.2, an increase in the amount of frequency response from proportional droop providers assists in the initial frequency containment, but can lead to exacerbation of frequency recovery challenges. However, with control scheme changes, these same units can deliver a substantial improvement in frequency recovery dynamics.

Termed frequency recovery mode (FRM), the proposed control scheme changes would allow units to autonomously detect an extended extreme frequency excursion, and automatically switch into an alternative control mode that would adjust their active power setpoint in a controlled manner, until frequency is recovered. The generator can then gradually return to normal operation once frequency is restored and the system is in a stable and secure state.

FRM design

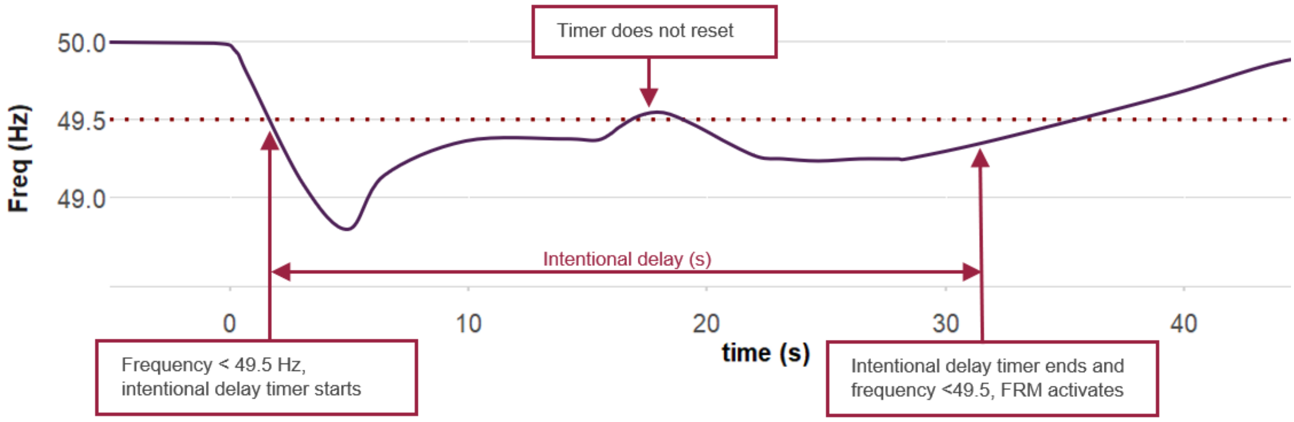
There are a range of possible ways that FRM could be implemented. For these studies, AEMO has modelled a FRM behaviour that operates as follows:

- The generating unit autonomously detects an extended extreme frequency excursion (for these studies, a FRM trigger setting of frequency outside of 49.5 to 50.5 Hz and still outside this range after 30 seconds with another outside 49.75 to 50.25 Hz for 450 seconds was applied). Figure 49 provides an illustration.
- When triggered, the generating unit automatically switches into an alternative control mode that gradually adjusts the unit's active power setpoint in the desired direction in a controlled manner. For these studies, when FRM is triggered in response to an extended under-frequency, units were modelled to gradually ramp up their active power setpoint toward their maximum power output linearly at a rate of 1% of capacity per second, until frequency recovers to >49.85 Hz or maximum output is reached, and then hold at that level. Unit output becomes the power setpoint plus the proportional component. This aims to assist frequency

recovery as well as countering the effects of inverter-based resources moving back along a droop curve as frequency recovers.

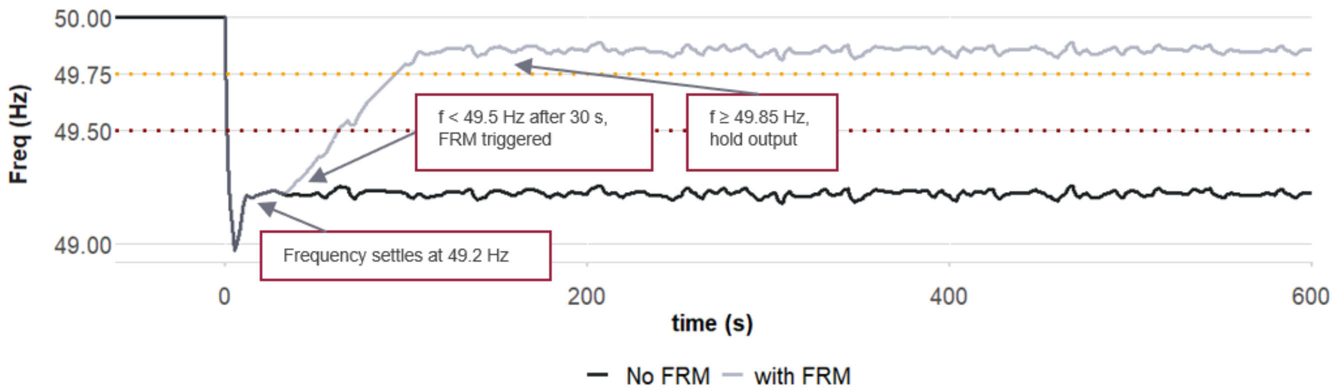
- Once power system frequency is restored and the system is in a stable and secure state (this could be autonomously triggered once frequency is within appropriate bounds for a pre-defined duration), units can return to normal operation by gradually reducing their active power setpoint to the normal level over a period of time[57] (for example, return to target over a trading interval).

Figure 49 Modelled activation method for FRM in an underfrequency event



The case study in Figure 50 shows the timing and impact of FRM on frequency recovery. Following the initial contingency, a combination of UFLS action and proportional response partially recovers and then stalls frequency at 49.2 Hz. In the black scenario, without FRM, there are no further dynamics to recover frequency, and the case fails to meet acceptance criteria. In contrast, in the grey scenario (with FRM enabled), FRM activates when frequency remains below 49.5 Hz for more than 30 seconds. FRM-enabled units increase their active power setpoint, driving frequency up. Frequency reaches 49.85 Hz, units stop ramping, hold their setpoint and continue to provide proportional response. This sequence of events recovers frequency, and sustains that response until implementation of the manual measures required to move to stable and secure island operation.

Figure 50 Case study example – effect of FRM operation on frequency recovery (settled below 49.5 Hz)

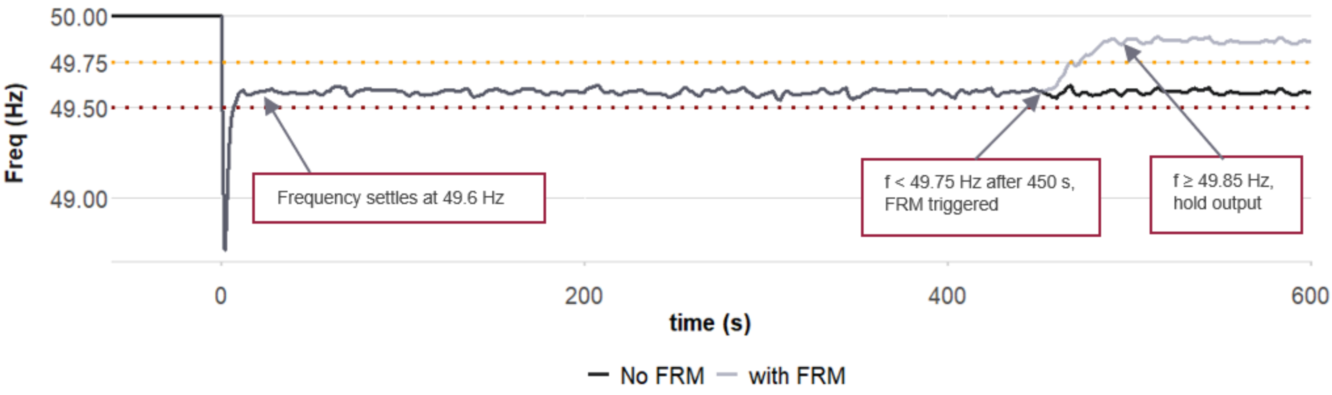


For simplicity of comparison, delayed UFLS has been disabled in this illustrative scenario.

[57] Fast withdrawal of this response type would be detrimental and likely result in another fast decline of frequency.

The case study in Figure 51 demonstrates the second trigger setting modelled for FRM that addresses risk cases only. Following the initial contingency, UFLS action and proportional response arrest and recover frequency, settling at 49.6 Hz. This is above the trigger frequency for delayed UFLS and without additional helpful dynamics would result in a risk scenario. After 450 seconds, frequency remains below 49.75 Hz, and FRM-enabled units increase their active power set point driving frequency up. When the frequency reaches 49.85 Hz, these units hold their setpoint and continue providing proportional response.

Figure 51 Case study example – effect of FRM operation on frequency recovery (settled above 49.5 Hz)



The resulting effect of FRM is like having a switched block of generation or load which would deliver a step change in energy output (similar to UFLS), while also continuing to deliver an overlaid droop response to help stabilise frequency. Alternative design implementations are also possible, noting the desired specification of behaviour is to both recover frequency and prevent immediate withdrawal of fast acting proportional response as frequency recovers.

Units capable of providing FRM

FRM could technically be provided by any generating unit, including synchronous generating units. The cost, however, of retrofitting the necessary control schemes to existing plant is likely to be higher than enabling it on new plant that is yet to be commissioned. Additionally, the retrofit of FRM on older synchronous units may also be more likely to encounter technical limitations in implementation.

Thus, while implementation of FRM on all types of generating units would be beneficial, it is proposed that efforts should focus on implementation of FRM for new connections, and particularly on BESS which are likely to be both fast responding, and have both headroom and footroom available to respond in the majority of periods (wind and solar generation will typically only deliver frequency response during over-frequency events).

Distributed resources

It may also be possible for distributed energy resources (such as distributed BESS) to provide FRM. Distributed BESS quantities are currently relatively small but will increase in future. Inverters that connect these systems to the network are governed by AS/NZS 4777.2. The 2020 standard requires proportional droop response from distributed BESS, but the speed of response is not tightly defined, allowing for slower response. Understanding of the impact of these resources on frequency recovery requires further investigation.

Requiring some version of FRM could be considered in future iterations of the AS/NZS4777.2 standard.

FRM for under-frequency versus over-frequency

Frequency recovery mode can be applied to address both sustained under- and over-frequency conditions (with the settings mirrored for over-frequency events). The examples presented focus on under-frequency events (which are the main focus of this report). In under-frequency events, the main resources delivering the FRM are BESS with headroom available (since other types of inverter-based resources, such as wind and solar generating units, are assumed to have no headroom available to increase generation in response to an under-frequency event). Therefore, BESS are the focus for enablement of FRM in the examples provided.

In over-frequency events, any units that reduce output proportional to frequency (including wind and solar resources) are likely to have available footroom which would be useful for FRM. Therefore, for over-frequency studies, it has been assumed that FRM is also enabled on wind and solar generating units, such that they can contribute to frequency recovery during over-frequency events.

Interaction with very fast FCAS

Two new FCAS markets – very fast raise and very fast lower – will come into effect from 9 October 2023[58]. The introduction of these new markets may drive interest in establishing a combination proportional and switched controller type (mentioned in Section 8.4.2). This response type is expected to reduce the frequency recovery challenges associated with proportional only controllers as the switched component provides a sustained active power response.

Although potentially helpful, participation levels and controller types in the new markets remain uncertain at this stage. Additionally, the units are not guaranteed to provide a response unless dispatched to do so, meaning the response cannot be relied upon in a South Australian island immediately following a non-credible separation. In this circumstance, FRM becomes a backstop mechanism ensuring that frequency recovery requirements are met even if the FCAS market response is not adequate to do so. In the event that the market response is adequate to recover frequency, FRM will not be triggered.

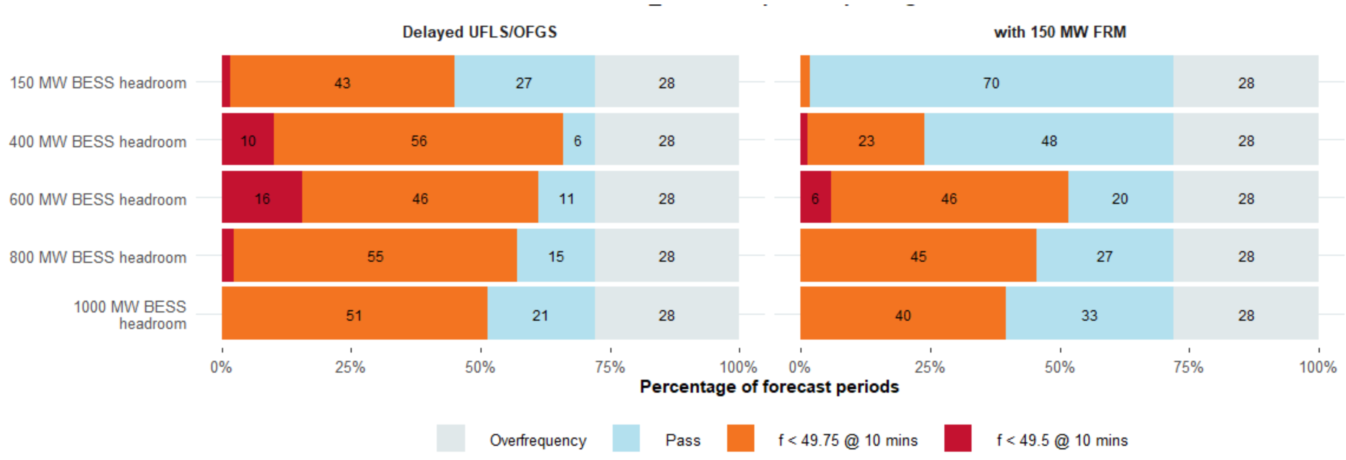
9.4.2 Expected power system security outcomes

Figure 52 compares the results with delayed UFLS and OFGS implemented as recommended (left column) with the results following the addition of FRM enabled on 150 MW of BESS capacity (right column) for varying levels of total BESS headroom available. Only the no synchronous generator requirement dispatch scenario results are shown, however similar outcomes were observed for the 2 x synchronous generator requirement scenario.

The results indicate that FRM activated on 150 MW of available battery headroom is effective at managing almost all risk for lower levels of total BESS headroom, but its impact becomes less effective if BESS headroom is higher, with up to 6% of cases still failing to meet the FOS requirements and a further 46% of cases at risk in the worst instance.

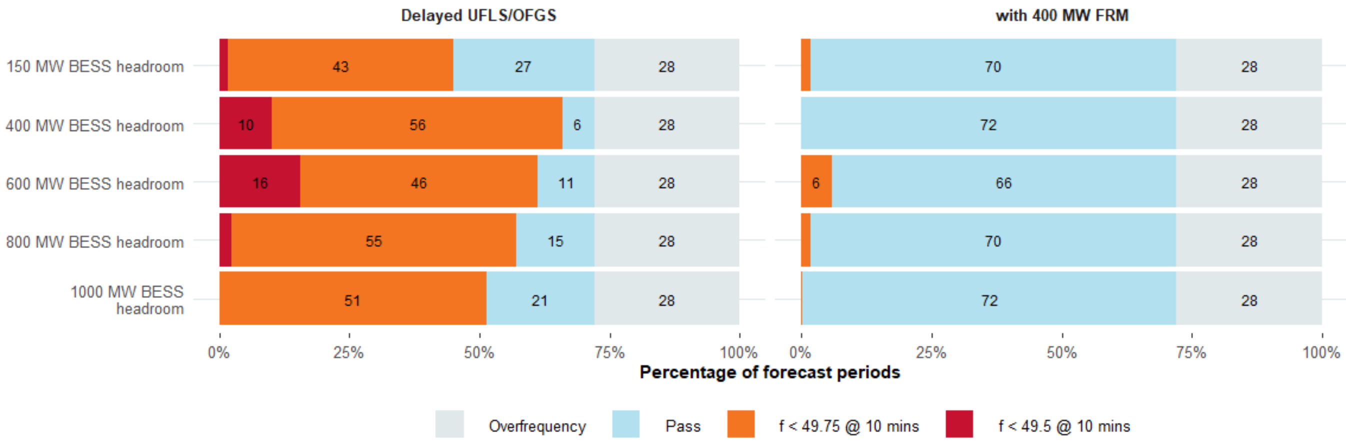
[58] AEMO (May 2022) Amendment of the Market Ancillary Service Specification (MASS) – Very Fast FCAS, https://aemo.com.au/consultations/current-and-closed-consultations/amendment-of-the-mass-very-fast-fcas#:~:text=On%2015%20July%202021%2C%20the,to%20control%20power%20system%20frequency.

Figure 52 Impact of FRM enabled on 150 MW on under-frequency recovery outcomes (2022-23 and 2023-24) with varying BESS headroom, no synchronous generator requirement



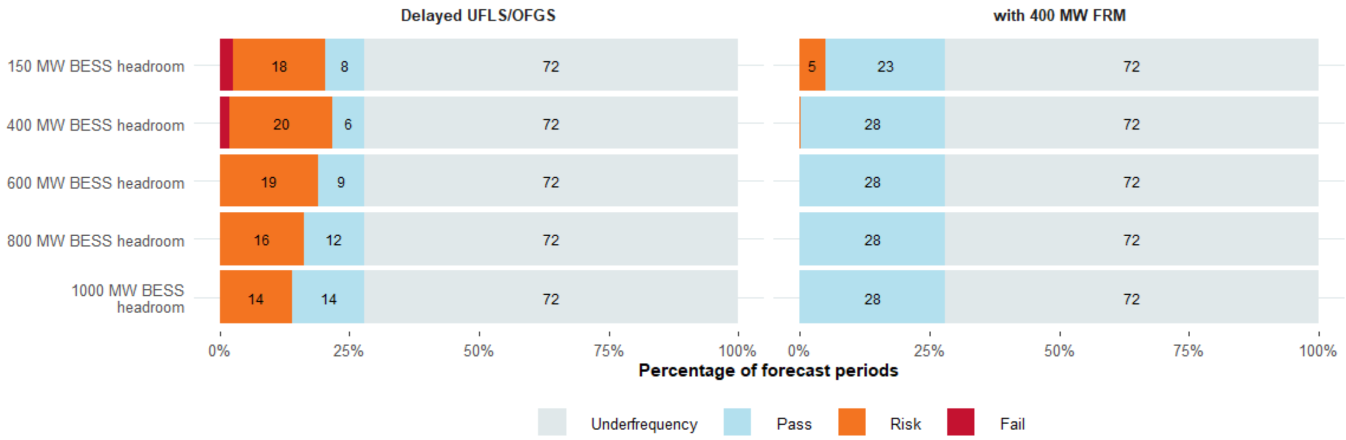
In Figure 53, the amount of BESS with FRM enabled was increased up to 400 MW. The results indicate better performance, particularly with increased BESS headroom available, compared with 150 MW of FRM. All failure cases and the majority of risk cases are managed for increasing quantities of BESS headroom.

Figure 53 Impact of FRM enabled on up to 400 MW on under-frequency recovery outcomes (2022-23 and 2023-24) with varying BESS headroom, 2 x synchronous generator requirement



FRM implemented on 400 MW of BESS providers also shows significant improvement in over-frequency separation scenarios. The results in Figure 54 show that with 400 MW of FRM, over-frequency failure cases are eliminated and risk cases are significantly reduced or eliminated across all levels of total BESS headroom.

Figure 54 Impact of FRM enabled on 400 MW on over-frequency recovery outcomes (2022-23 and 2023-24) with varying BESS headroom, no synchronous generator requirement



9.4.3 Estimated benefits

Table 42 provides an estimate of the benefits of enabling FRM in South Australia (assuming that the proposed changes to delayed UFLS and OFGS have been implemented and 150 MW of BESS headroom is available). The approach and assumptions applied are identical to those outlined in Section 8.5 and Appendix A4.

Table 42 Benefits of FRM based on avoiding risk of cascading failure (2022-23 and 2023-24)

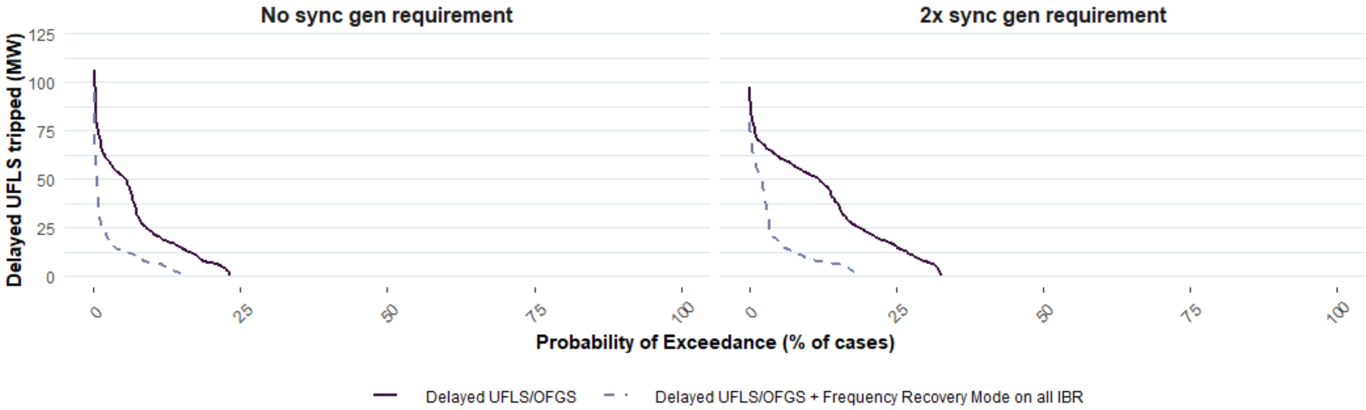
	Under-frequency cases only (FRM enabled on all BESS)			Including over-frequency cases (FRM enabled on all IBR including BESS, wind and solar)		
	Reduction in USE (MWh/year)	Estimated benefits ($mil/year)		Reduction in USE (MWh/year)	Estimated benefits ($mil/year)	
		Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement (cost-reflective bidding profiles)	30 - 134	$1 - $6	$3 - $12	41 - 183	$2 - $8	$4 - $16
Minimum 2 synchronous unit requirement (historical bidding profiles)	14 - 64	$1 - $3	$1 - $6	24 - 106	$1 - $5	$2 - $9

Compares estimated USE in the scenario with delayed UFLS/OFGS implemented, with scenario also including FRM on all IBR

FRM reduces load shedding

In addition to reducing USE associated with the possibility of cascading failure, FRM enablement also leads to a reduction in load interrupted by delayed UFLS. Figure 55 shows that with FRM enabled with the settings as modelled in these studies, the total load disconnected by delayed UFLS operation is reduced from 51-62 MW to 13-18 MW in 95% of cases.

Figure 55 Amount of delayed UFLS tripped with and without FRM enabled



Assuming that load interrupted on UFLS is typically restored in one hour, it is estimated that enabling FRM on all inverter-based resources would result in a reduction of 4.4-8.5 megawatt hours (MWh) of USE per annum (equating to $0.1-0.2 million per annum at a standard VCR of $42.32/kilowatt hour ([kWh]) associated with avoided UFLS. The residual delayed UFLS disconnection is caused by inadequate headroom available on FRM following the initial contingency to recover the frequency above 49.5 Hz.

9.4.4 Additional costs

Commissioning costs

AEMO's initial discussions with two inverter-based resources generation operators in South Australia did not reveal any technical barriers to implementation of FRM.

Generating units will incur costs in designing, commissioning and testing the control schemes required to deliver FRM. This is currently not a standard capability required in international markets, and therefore design and implementation of this capability is anticipated to require engagement of OEMs. For retrofit in particular, the cost of engaging OEMs is often non-trivial. Application of FRM to new units that have not yet completed the design phase is likely to be lower cost than retrofits.

Further consultation is required to fully understand the total cost to add FRM functionality to new and existing generating units, and this will likely vary case-by-case.

Reservation of headroom for FRM

There is no expectation that any generating unit would reserve headroom for delivery of FRM as this would result in lost opportunity costs for market participants. Rather, for this modelling it has been assumed that FRM is enabled on units, and delivered with whatever headroom happens to be available on these units at the time of the non-credible separation event.

The modelling conducted here accounts for varying levels of headroom available on BESS for delivery of FRM in response to an extended under-frequency event (unless otherwise stated). Analysis of historical dispatch patterns in 2021 indicated that the aggregate BESS in South Australia (205 MW capacity) had at least 150 MW of headroom available in more than 75% of periods.

Additional energy requirements

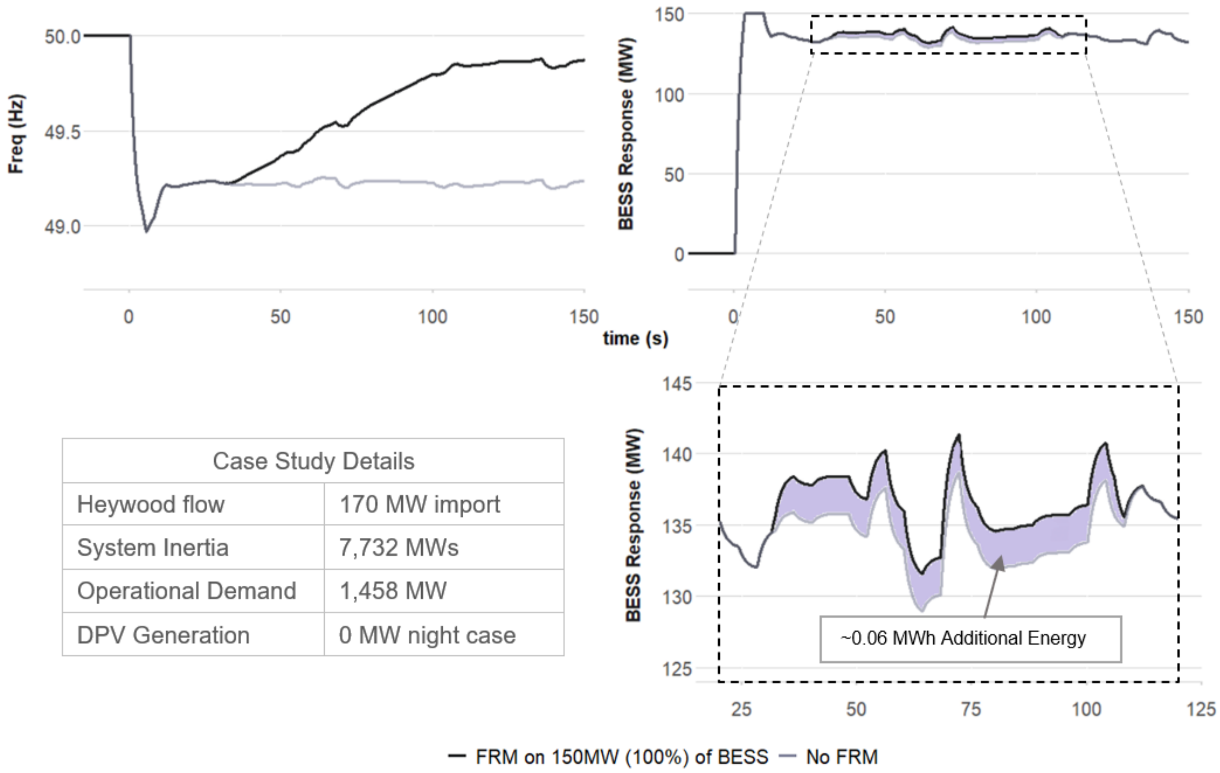
The proposed FRM settings involve very wide bounds (not triggered unless frequency is below 49.5 Hz for more than 30 seconds). This means that FRM should only be triggered rarely in response to a non-credible separation event (assumed to occur approximately two to four times every five years).

In the rare circumstances when FRM is triggered, these studies indicate the additional energy delivered by FRM-enabled plant is minimal.

Figure 56 shows a case study where frequency settles at approximately 49.2 Hz following a non-credible separation event. The grey scenario illustrates the outcome with no FRM enabled, and the black scenario indicates the outcome with FRM enabled on 150 MW. The frequency outcomes (left panel) show the dramatic improvement in frequency recovery with FRM enabled. The right panel shows the response of the BESS in the scenario. The response of the BESS is almost identical between the two scenarios (with and without FRM), because only a very small amount of energy injection is required to drive a significant frequency recovery. In this case the additional energy required for FRM is ~0.06 MWh or an additional ~3 MW over 80 seconds (delivered by an aggregate of 150 MW of BESS headroom).

The small amount of energy required to drive frequency recovery is due to units continuing to provide proportional response, so as their active power set point increases and frequency recovers, they are also reducing their proportional response.

Figure 56 Case study: Energy required to recover frequency with FRM

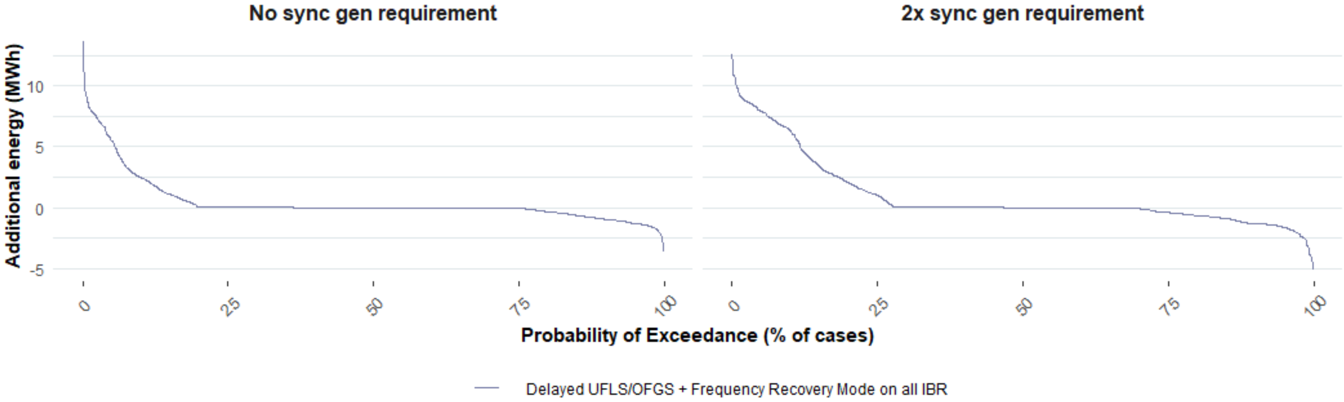


Case Study Details	
Heywood flow	170 MW import
System Inertia	7,732 MWs
Operational Demand	1,458 MW
DPV Generation	0 MW night case

For simplicity of comparison, delayed UFLS has been disabled in these illustrative scenarios.

Figure 57 shows the total additional energy required from batteries over the 10-minute simulation time with FRM enabled, across all the modelled cases. For 75-85% of cases there is less than 1 MWh required. The largest amount required in any cases is a maximum of 13 MWh (compared with how inverter-based resources in the system would have otherwise behaved under their inherent droop-based response with delayed UFLS implemented). Furthermore, ~25% of cases see a reduction in energy delivered if FRM is enabled. This occurs in over-frequency cases where FRM reduces output and in some under-frequency cases because the earlier recovery of frequency (assisted by FRM) allows some additional DPV reconnection to occur, which more than offsets the FRM contribution required in these cases.

Figure 57 Additional energy required from FFR with FRM enabled over the first 10 minutes



This indicates that the additional energy delivered by FRM-enabled units is very small and not a material contributor to the cost of enabling and delivering FRM.

9.4.5 Recommendation

This analysis suggests that FRM would provide meaningful benefits in South Australia to assist frequency recovery. As demonstrated in Section 9.1.2, the effectiveness of delayed UFLS reduces with an increased quantity of proportional response. FRM implemented on 400 MW of BESS units provides a solution that is robust to increases in BESS headroom as new capacity continues to be commissioned in the South Australian network.

For existing plant, there will likely be retrofit costs associated with updating control schemes and interaction with OEMs. This can be explored further with the existing capable plant operators in South Australia to understand likely costs and any potential barriers.

AEMO is working with ElectraNet on suitable FRM implementation pathways.

Is this issue specific to South Australia?

Frequency recovery challenges may occur after any significant non-credible contingency, but are likely to be most prevalent in regions that can island. In the resulting island, following a non-credible separation, there may not be any FCAS enabled, and it may take 10 minutes or more for confirmation of the islanding event, enablement of the correct constraint sets, AGC settings, and updates to dispatch.

This report has focused on analysis of frequency recovery challenges in South Australia only, but it is plausible that similar challenges could occur in Queensland following a non-credible separation event (as demonstrated following the historical non-credible separation event detailed in Section 8.1.2). Islanding of other combinations of regions and sub-regions can also occur (such as a combined Victoria and South Australia island, which could result from a separation at the Victoria – New South Wales Interconnector [VNI], as occurred on 4 January 2020 due to bushfires).

Historical events have also shown that frequency recovery challenges can exist even in an interconnected region. For example, following the non-credible separation of South Australia on 30 January 2020, the larger mainland island comprising Queensland, New South Wales and Victoria failed to meet the FOS for recovery above 49.85 Hz within 10 minutes[59]. Prior to the separation, a significant percentage of the total enabled contingency raise FCAS and 30% of the raise regulation FCAS was enabled in the South Australian islanded region. This caused a shortfall in available frequency recovery services in the remaining mainland until constraints and dispatch were adjusted.

Given uncertainties in how the future power system will evolve, the benefits of implementing FRM in other regions are difficult to model and quantify.

9.5 Option 5: Fast start unit energy injection

9.5.1 Description

As outlined in Option 4 above, FRM is highly effective in driving frequency recovery (if implemented on enough units) and adequately reduces fail and risk cases. If implementation of FRM on up to 400 MW of capable units proves to be unachievable, fast start units could be used to provide a complementary response by autonomously detecting an extreme extended under-frequency condition, automatically synchronising and ramping up to assist frequency recovery.

An estimated ~700 MW of fast start units in South Australia are able to start-up and synchronise within the 10-minute timeframe[60] and therefore may have the potential to aid frequency recovery following an under-frequency event by injecting active power into the system[61]. This response could assist FRM where there is a shortfall in the quantity activated and in the small proportion of cases where there is insufficient energy or headroom available on FRM providers[62].

Fast start unit response design

This capability could be delivered in a number of ways. In this study, the capability has been modelled as follows:

- The unit autonomously detects local frequency below 49.5 Hz for more than ~10 seconds (Figure 58 provides an illustration).

[59] AEMO (November 2021) Final Report –Victoria and South Australia Separation Event on 31 January 2020, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-victoria-and-south-australia-separation-event.pdf?la=en

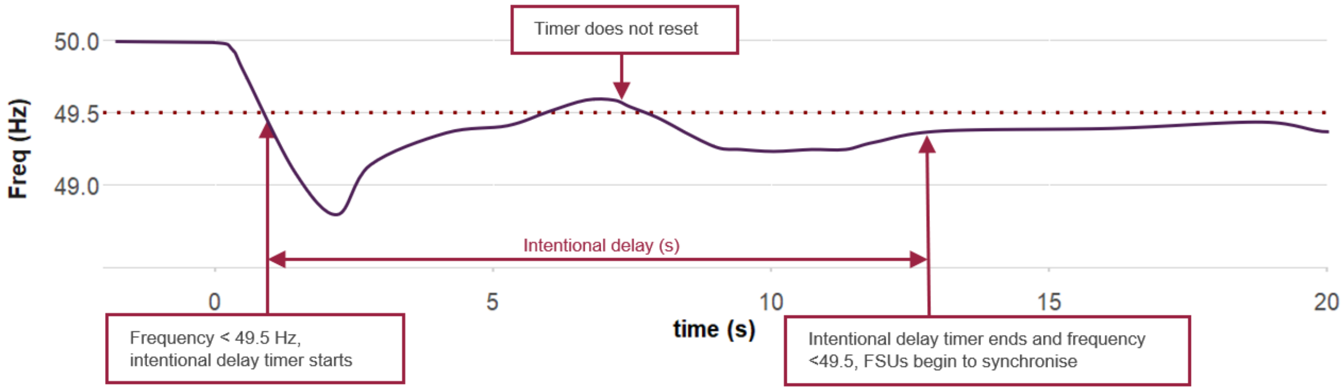
[60] Based on their historical bidding behaviour

[61] The standard definition of a Fast Start generating unit is a unit that can synchronise and reach its minimum loading within 30 minutes, and can synchronise, reach minimum loading, and shut down in less than 60 minutes. The requirement for delivering the capability noted here is defined differently, requiring a unit to synchronise and ramp up to minimum loading in less than 10 minutes.

[62] In 2021 there was sufficient energy to provide a full 15 minutes of FRM response more than 99% of the time. Insufficient headroom is the more likely source of residual risk scenarios.

- The unit synchronises and begins to ramp up. For this analysis, fast start unit synchronisation and start up times have been modelled based on averages of their historical bids. For some units, there may be a requirement to start from a warm or hot state to meet this timing.
- The unit then ramps up its set point to at least the minimum loading level, then continues to ramp up unless frequency has exceeded 49.9 Hz or the unit reaches maximum loading, at which point the unit will hold its output. The unit simultaneously sustains its normal primary frequency control droop response (around the unit's set point).

Figure 58 Modelled activation method for fast start units



Because units have a minimum loading level, it is possible to trigger an over-frequency event by having too many units start up at the same time. Therefore, fast start units need to be staggered in a manner that will minimise overshoot. The exact combination of how units may be staggered will depend on each unit's specific start up parameters. For this modelling, two blocks were used:

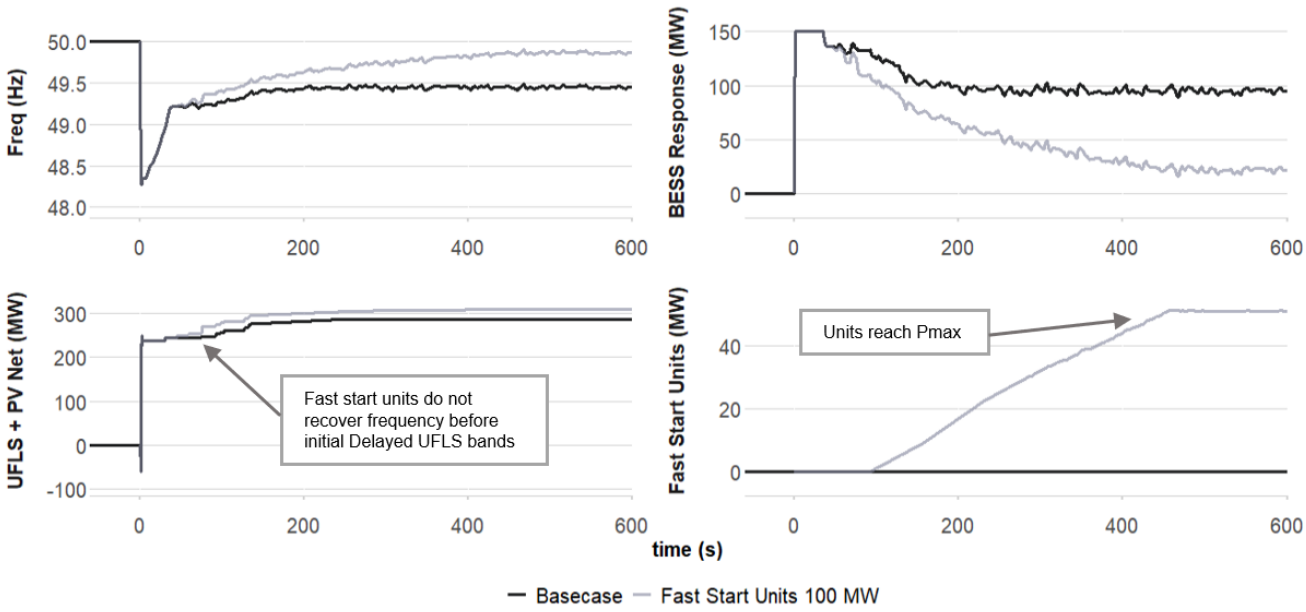
- Block 1 – units start up after frequency has been below 49.5 Hz for ~10 seconds.
- Block 2 – units start up after 180 seconds if frequency is still below 49.5 Hz.

Fast start unit capacity was split evenly between the two blocks.

An example with ~100 MW of total fast start units enabled for frequency recovery response is shown in Figure 59. In this case, 50 MW of fast start units are placed on the first band and 50 MW on the second. Only the first band is triggered in this example, as frequency has recovered above 49.5 Hz by the ~180 seconds time.

Units providing this type of response autonomously will likely be non-conforming with their dispatch instruction at the time (which may still be based on a dispatch calculation prior to the non-credible separation). There is also a possibility that frequency will recover above 50 Hz while units are still ramping up to their minimum loading level, which will mean that delivering this service will detrimentally impact their regulation FCAS recovery (causer pays) factors. Units enabled to deliver this fast-start recovery service should therefore be exempted from those adverse market or compliance impacts under these conditions.

Figure 59 Case study: Improved frequency recovery outcome using fast start units

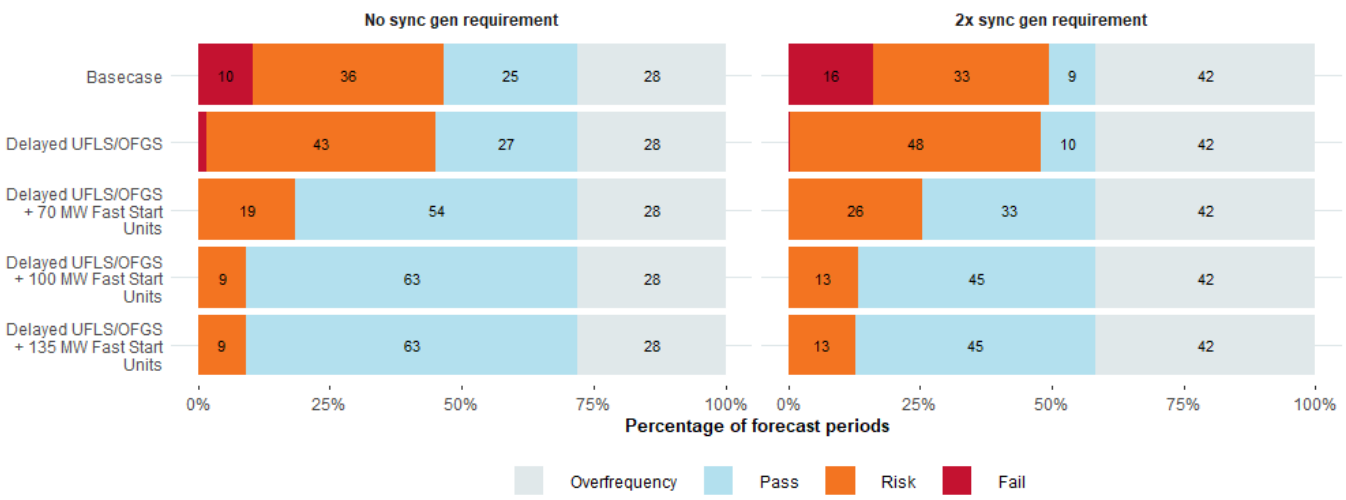


This example case does not have FRM enabled.

9.5.2 Expected power system security outcomes

The impact of varying amounts of fast start units assisting with frequency recovery is shown in Figure 60. It is assumed that delayed UFLS (Option 1) and delayed OFGS (Option 2) have been implemented, but FRM (Option 3) has not yet been implemented.

Figure 60 Impact of fast start units on frequency recovery outcomes



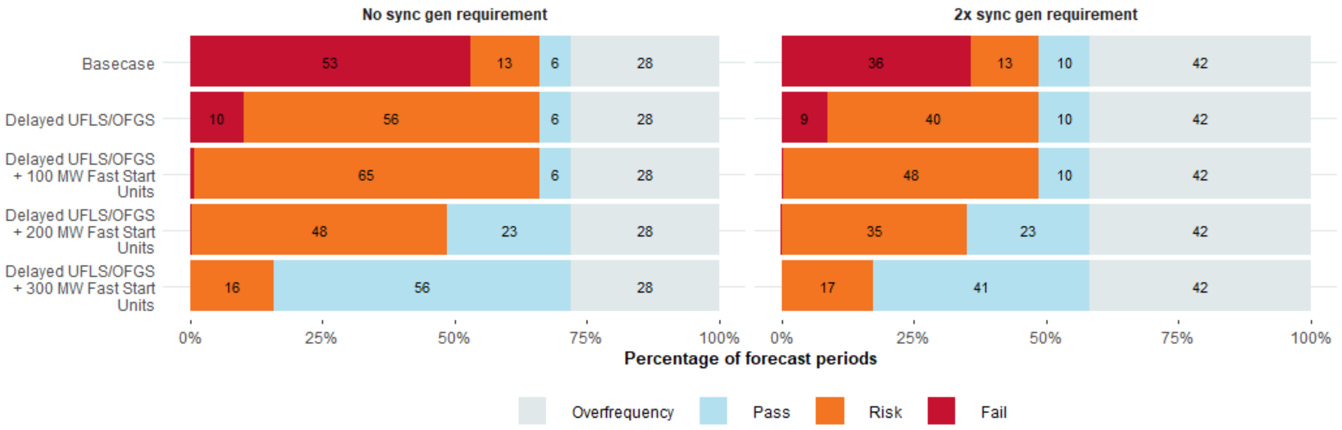
Fast start units not only address residual fail cases not addressed by delayed UFLS, but also reduce the number of risk cases by driving frequency recovery closer to 50 Hz. Risk and fail cases are reduced from ~50% of the time down to 9-13% of all cases. The residual risk cases are a result of frequency having recovered above 49.5 Hz resulting in fast start units not triggering (based on the modelled settings).

The results indicate a diminishing returns effect; there is negligible further improvement from increasing fast start recovery-responsive unit levels beyond ~100 MW (assuming a total of 150 MW of FFR headroom). This is unlike FRM, where the modelling indicates that there are benefits from all fast acting inverter-based resources being enabled for FRM (to prevent the detrimental impacts of their withdrawal as frequency recovers).

In future, if additional proportional response capacity comes online without FRM enabled, additional fast start units may be required to counter their withdrawal as frequency recovers. Figure 61 shows the results of a study where its assumed there is 400 MW of fast acting proportional headroom available (increased from 150 MW). The results indicate that 100 MW of fast start units act to significantly reduce residual fail cases from delayed UFLS, but have very limited impact on improving the outcomes in risk cases. A significant reduction in risk cases is not seen until the total available fast start capacity exceeds 200 MW, and 300 MW is required to get back to similar levels of risk as with only 150 MW of fast acting proportional response.

Although an estimated 700 MW of fast start unit capacity is theoretically capable of coming online and providing a response, different unit capabilities, start-up requirements and costs may make it far more challenging to procure a total of 300 MW of fast start units, compared with the initial 100 MW. For this reason, fast-start unit enablement should only be considered as second preference to FRM implementation.

Figure 61 Impact of fast start units on frequency recovery outcomes with 400 MW of BESS headroom



9.5.3 Estimated benefits

Table 43 provides an estimate of the benefits of enabling fast start units for frequency recovery in South Australia. The approach and assumptions applied are identical to those outlined in Section 8.5 and Appendix A4.

Table 43 Benefits of fast start units for frequency recovery (2022-23 and 2023-24)

	Reduction in USE (MWh/year)	Estimated benefits ($mil/year)	
		Standard VCR	2 x VCR
No minimum synchronous unit requirement (cost-reflective bidding profiles)	31-128	$1-$6	$3-$12
Minimum 2 synchronous unit requirement (historical bidding profiles)	14-51	$1-$2	$1-$4

Assumes delayed UFLS and OFGS are implemented, but FRM is not enabled.

Interaction with delayed UFLS

Unlike FRM, fast start units take several minutes to respond and therefore do not significantly reduce triggering of load shedding via delayed UFLS (with settings as proposed).

9.5.4 Additional costs

Initial engagement with possible providers of this service in South Australia has not indicated any technical barriers to implementation.

Fast start units will incur a once-off commissioning cost to enable the proposed frequency response capability. This is likely to require engagement of the OEM. There may also be some ongoing costs associated with periodic testing to ensure the capability remains enabled as required. These costs will likely vary unit to unit.

Units will not have the available headroom to deliver this service if they are already operating close to maximum capacity at the time of the non-credible separation. Also, some units may only be able to deliver the required start-up times if they are in a warm state at the time of the non-credible separation. Given the rare occurrence of non-credible separation events (compared with credible contingency events), it is proposed that units delivering this service would just be enabled to deliver the service wherever possible, depending on their status when a non-credible separation occurs. Selection of appropriate units to deliver the service would be based on those whose typical operation has them in the appropriate state for a reasonable proportion of the time.

This is different to traditional FCAS or system restart services, where there are penalties if providers enabled for the service do not deliver it when required. This different approach aims to minimise delivery costs for services that aim to manage rare non-credible events, and is proposed as appropriate given the low probability of a non-credible separation event.

9.5.5 Recommendation

This analysis suggests that enablement of fast start units to assist with frequency recovery would deliver benefits. With the present amount of FFR in South Australia, approximately 100 MW of fast-start units appears beneficial. Larger quantities of fast-start recovery-enabled units will likely be required if significant additional proportional responding capacity is installed without FRM enabled.

AEMO recommends this option is explored further with a view to better understanding possible costs and enablement barriers. The benefits of this approach are primarily to fill any shortcomings in enabling FRM on 400 MW of BESS capacity.

9.6 Option 6: Introduce Delayed FCAS requirements for South Australia

9.6.1 Description

The delayed raise and lower contingency FCAS services (R5/L5) might deliver some of the frequency recovery capability required. Enablement of these services all the time (in system normal conditions) would be required to ensure that following separation, R5 FCAS would be available to respond in South Australia, in the period before central dispatch is reconfigured for islanded operation.

Contingency FCAS is currently procured to manage credible contingencies only. Under system normal conditions it can be enabled in any NEM region, and as such is not guaranteed to be available in South Australia following a non-credible separation.

Services would need to be enabled in all periods

As discussed in Section 8.2.3, this analysis indicates that frequency recovery challenges cannot be predicted from pre-event conditions. This means the full requirement for this service would need to be enabled in all periods. It is anticipated that raise services (R5) would be enabled when South Australia is importing (such that a separation would lead to an under-frequency condition), and lower services (L5) would be enabled when South Australia is exporting (such that a separation would lead to an over-frequency condition).

It is estimated that in the order of ~100-200 MW of R5/L5 would need to be enabled in South Australia in most periods, although the exact quantity would depend on the particular properties of the response of the units delivering the service.

Regulation FCAS

Enabling regulation FCAS in all periods in South Australia may not assist as required, since it can take up to 10 minutes or more for AEMO to confirm a separation has occurred and update FCAS arrangements (ensuring the frequency reference is being correctly applied from measurements within the South Australian island). This means that regulation FCAS targets would not be set correctly immediately after a non-credible separation to allow any enabled services in the region to properly assist frequency recovery.

9.6.2 Benefits

There is an existing market for R5/L5 services, which would allow a relatively simple enablement of these services via that existing market, utilising existing mechanisms for cost recovery.

9.6.3 Costs and limitations

Higher costs than other options proposed

When a proponent is enabled for delivery of FCAS, they must reserve the required headroom for delivery of the service. This impacts their ability to participate in the energy market and in delivery of other services. The opportunity costs of FCAS enablement can be significant. This contrasts with other considered options that do not require reservation of any headroom, and therefore do not impact the ability to deliver energy or other services. For this reason, enabling either R5 or L5 in South Australia in all periods is likely to cost more in the longer term than the other options considered above.

Response may not meet requirements

R5/L5 providers have various methods of delivering their services. Some deliver a response via a frequency droop, which will not deliver the necessary frequency recovery dynamics (a change in active power setpoint is required to drive frequency recovery). Other providers deliver their response via a switched mechanism, which is more likely to assist frequency recovery as required. At present, there is no way to distinguish between these methods in the FCAS market and selectively enable enough providers with switched responses.

Reducing geographic diversity

Increased requirements for R5/L5 within South Australia could distort the geographic diversity of FCAS enablement across the NEM. In system normal periods, the total requirement for R5 in the NEM is typically in the range of 400 to 500 MW. Adding specific requirements for local L5/R5 in South Australia would require that approximately a third of the total requirement is always enabled in South Australia.

This may adversely impact the R5/L5 FCAS availability in other regions following different contingency events that result in poorer frequency performance in other regions. It may also limit market opportunity for providers in other regions, or have other distortionary effects.

9.6.4 Recommendation

AEMO does not recommend pursuing this option further, since the other options available are likely deliver the response required more reliably and at lower cost.

9.7 Recommended options

The options considered and the recommendations for each are summarised in Table 44.

Table 44 Recommended options for frequency recovery

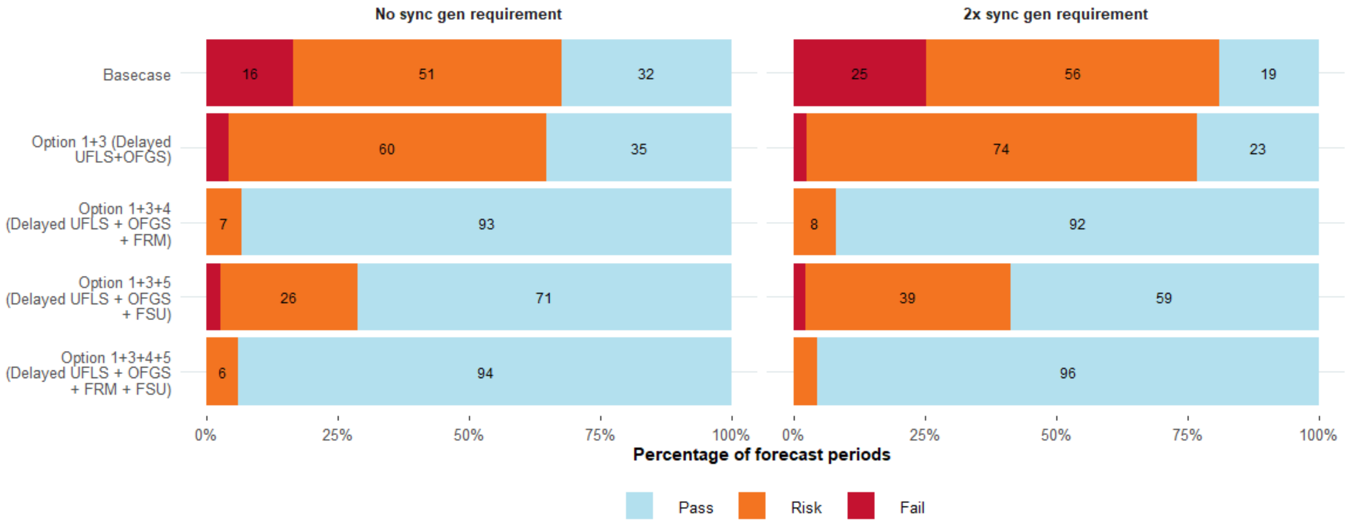
Options	Details	Recommendation	
Option 1: Delayed UFLS	Expand delayed UFLS scheme to include an average of 120 MW of total load.	✓	• AEMO has already recommended this action to SAPN. • Falls under existing NSP responsibilities defined in NER S5.1.10.1(a).
Option 2: Modification of existing UFLS bands	Reduce number of UFLS bands while maintaining total load on the scheme.	✗	• Do not recommend. • Less improvement and less robust than other options and increases risk of frequency overshoot.
Option 3: Delayed OFGS	Frequency may settle above 50.5 Hz if there is overshoot following an under-frequency event. Introduce delayed OFGS scheme with four blocks (~120 MW wind capacity each block). Also addresses over-frequency cases following separation.	✓	• AEMO and Electranet are collaborating on implementation • Falls under existing NSP responsibilities.
Option 4: Frequency Recovery Mode (FRM)	Implement FRM on 400 MW of proportional resources, to assist frequency recovery and offset detrimental withdrawal as frequency recovers.	(✓)	• Explore potential for implementation on new or existing units (especially BESS in South Australia). • AEMO is working with ElectraNet on implementation pathways.
Option 5: Fast start units (FSU) energy injection	Introduce control schemes on ~100 MW of fast start units (FSUs) to automatically detect extended under-frequency, synchronise and ramp up.	(✓)	• Explore implementation if FRM cannot be feasibly implemented on 400 MW of capable units.
Option 6: Introduce local Delayed FCAS requirements	Introduce requirements for Delayed FCAS in South Australia in all periods.	✗	• Do not recommend. • May not reliably deliver the required response. • Higher costs than other options.

This combination of services results in a robust solution that will effectively recover frequency under a variety of operating conditions and resource availabilities. Delayed UFLS and OFGS provide a backstop that can be implemented relatively quickly, and addresses a large proportion of the highest risk cases. As more fast acting proportional response is added to the network, delayed UFLS is expected to become less effective at managing all frequency recovery risk cases. Implementing Frequency Recovery Mode provides a comprehensive long-term solution. If FRM cannot be feasibly implemented on 400 MW of units, fast-start units can provide complementary frequency recovery support.

9.7.1 Expected power system security outcomes

The frequency recovery outcomes for all cases (both South Australian import and export periods) with stacked options are shown in Figure 5. Implementation of the recommended options reduces fail cases from 16-25% of all periods to 0% and risk cases from 51-56% to 7-8% of all periods.

Figure 62 Stacking of frequency recovery mitigation options (over- and under-frequency)



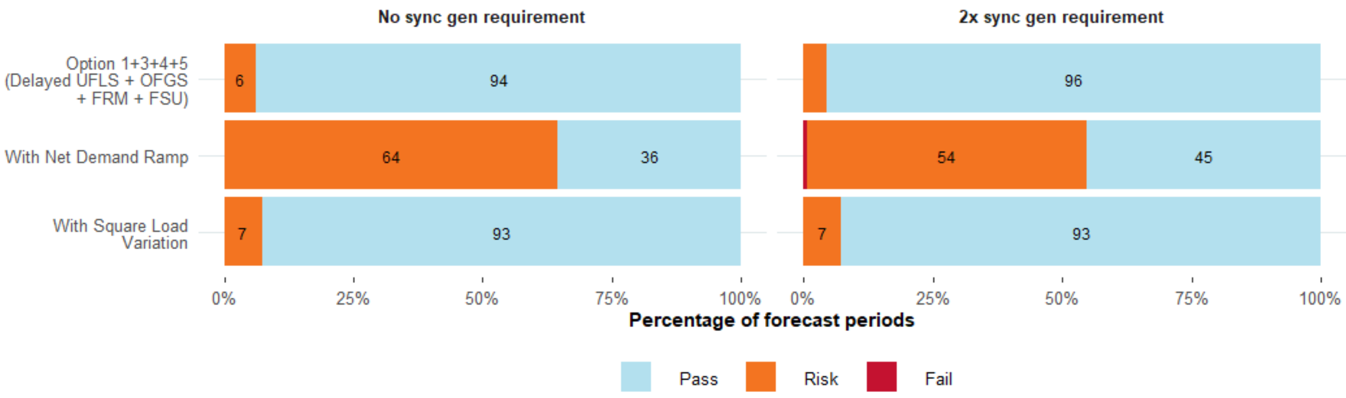
The inclusion of Option 5 (fast start units) is only recommended if the full implementation of FRM is not feasible.

Sensitivities

As noted in Section 8.4.1, there are a number of ways in which net demand variation or AGC setpoints may result in poorer frequency recovery outcomes than modelled in the base case above. The proposed options were checked against these sensitivity cases, to confirm they still deliver an adequate reduction in risk even under these more onerous possible cases.

The results shown in Figure 63 indicate that even with a worst-case net demand ramp working against frequency recovery, the proposed combination of options maintains the incidence of fail cases to below 1%. Risk cases increase under these conditions, but frequency is maintained within the FOS requirements.

Figure 63 Performance of recommended options with net demand and AGC variation



9.7.2 Estimated benefits

The total estimated benefits of the recommended options combined (Option 1+3+4) in terms of the reduction in USE are summarised in Table 7. The approach and assumptions applied are identical to those outlined in Section 8.5 and Appendix A4.

Table 45 Benefits of combined recommended options (2022-23 and 2023-24): Option 1+3+4

	Under-frequency cases only			Including over-frequency cases		
	Reduction in USE (MWh/year)	Estimated benefits ($mil/year)		Reduction in USE (MWh/year)	Estimated benefits ($mil/year)	
		Standard VCR	2 x VCR		Standard VCR	2 x VCR
No minimum synchronous unit requirement (cost-reflective bidding profiles)	100-444	$4-$19	$9-$38	120-531	$5-$23	$10-$46
Minimum 2 synchronous unit requirement (historical bidding profiles)	154-682	$7-$29	$13-$59	186-827	$8-$36	$16-$72

9.7.3 Additional costs

Additional costs are likely to be primarily related to the one-off commissioning costs to implement FRM and fast start unit responses. These will vary unit to unit.

10 Next steps

10.1 Implementation

AEMO is proceeding to implement the actions recommended in this report, in collaboration with SAPN and ElectraNet.

AEMO will continue to investigate South Australian separation events as necessary, and further challenges requiring further management measures may become apparent as that analysis continues. This report is based on the best of AEMO's knowledge at this time.

10.2 The protected events framework

This analysis was conducted following a recommendation in the 2020 Power System Frequency Risk Review for declaration of non-credible South Australia separation as a protected event. Following the analysis outlined in this report, AEMO does not intend to request the Reliability Panel to declare this contingency as a protected event.

All the recommended actions identified in these studies can be implemented without declaration of a protected event, and can be expected to minimise the identified power system risks associated with extreme under-frequency to non-material levels.

The key benefit of declaration, as noted in the 2020 PSFRR, would be to would make AEMO's management of these contingencies more transparent within the NER framework rather than relying on Regulation 88A. However, AEMO has identified that the declaration of a protected event could require additional measures to address the broader aspects of power system security envisaged by the NER for those events, which may not be justified or prudent at this time.

At present, the NER require that a protected event is treated identically to a credible contingency event in most respects. This is highly prescriptive, and in some cases it may not be feasible to assess and implement management measures that address each aspect of a satisfactory and secure operating state required to assure the prescribed level of power system security for a non-credible separation of South Australia (and not only the under-frequency risks quantified and analysed in the present studies).

The studies necessary to assess each dimension of a particular non-credible contingency event and determine a full suite of measures to ensure that each relevant power system requirement remains within the limits for a credible contingency event can constitute a very large body of work. Furthermore, potential solutions may not be technically or economically feasible to deliver. As these appear to be pre-requisites to the declaration of a protected event, AEMO is not in a position to provide the extended cost-benefit analysis that would be necessary to support the Reliability Panel's consideration. This means that the identified system collapse risk cannot be managed through the protected events framework without a significant delay, or even at all.

In this report, AEMO has proposed a limited set of measures that appear cost-effective and suitably manage the identified risks of uncontrolled under-frequency on separation leading to system collapse, while making the risks and the limitations of the studies completed in this assessment clear to the Reliability Panel and other stakeholders.

The presently identified risks have a limited duration (only until PEC Stage 2 is fully commissioned). In the interim, it appears sensible to take proportionate measures to manage the critical system collapse risk through existing frameworks (including Regulation 88A), and other initiatives that are under way to improve under-frequency response capability in South Australia.

More broadly, the NER requirements for managing power system security for protected events mean that the framework may not be fit for purpose, in that it does not facilitate transparent and expedient implementation of efficient management measures targeted to minimise critical power system risks as they are identified. In current conditions, qualified power system engineers are in limited supply, and even if funding were unlimited, it is necessary to carefully prioritise work on the many urgent power system issues that require analysis to support the successful energy transition. An alternative to the current protected events framework could consider approaches that are less prescriptive, and do not necessarily require aspects of power system security other than the primary risk to be managed within the same limits as a credible continency event. A simplified and less prescriptive framework could provide a pathway for AEMO to:

1. Identify an unmanaged risk that has the potential to lead to system collapse,
2. Develop suitable management measures (of any type), and
3. Propose these management measures to the Reliability Panel for consultation and consideration (with appropriate justification, consistent with the national electricity objective).

This simplified framework could focus on individual risks and efficient risk reduction actions, rather than a specific contingency event being declared as “protected”, with all the flow-on implications that then apply.

A1. Detailed modelling assumptions

Details of the modelling assumptions are summarised in Table 46.

Table 46 Assumptions used in the Simulink model

Variable	Description	Representation in model
Inertia	Inherent large spinning mass in the system from synchronous units	Included: • Inertia from the synchronous generators and condensers online in each dispatch interval is included in single mass model representation.
Over-Frequency Generator Shedding (OFGS)	Generation blocks designed to disconnect when frequency exceeds their trigger frequencies.	Included: • Modelled as lumped generation blocks for each frequency band with MW sizes based on forecast generation dispatch of units in the OFGS scheme.
Under Frequency Load Shedding (UFLS)	Load blocks designed to disconnect when frequency drops below their trigger frequencies.	Included: • Modelled as lumped load blocks for each frequency band • Block MW sizes based on historical load distribution across bands and scaled based on present installed distributed PV capacities associated with each band.
UFLS - Existing delayed UFLS	There is an existing UFLS band that will trip if frequency falls below 49 s and remains below 49.5 Hz after 30 s.	Included: • Modelled as a variable sized block based on historical feeder level timeseries data. • The forecast load on this band ranges between -14.7 to 37.4 MW over the two year period with an average of 13.7 MW.
Distributed PV disconnection	Distributed PV can disconnect en masse due to the inherent over and underfrequency trip settings of inverters. Most inverters in South Australia at present are either on the AS4777:2005 standard or the AS4777:2015 standard.	Included: • Modelled as lumped distributed PV blocks on each trip setting assuming: – Settings identified in AEMO's inverter frequency trip settings survey of 2005 standard inverters[63] – Assumed additional 2005 standard inverters disconnecting at 49.6Hz and 50.4Hz based on historical events with frequency nadirs or zeniths in this range – 50% of 2015 standard inverters disconnect in a similar manner to 2005 standard inverters dues to non-compliance.
Distributed PV over-frequency droop response	Distributed PV under the 2015 standard are required to exhibit a linear over-frequency droop response to frequencies above 50.25 Hz.	Included: • 30% of 2015 standard inverters are assumed to be compliant with the standard, exhibiting a linear over-frequency droop between 50.25 and 52 Hz.
Distributed PV reconnection	Once frequency has stabilised to acceptable thresholds, within their protection/droop settings, any disconnected distributed PV will begin reconnecting to the network and ramping up in generation.	Included in frequency recovery studies: • Inverters on the 2005 standard and 10% of inverters on the 2015 standard were aggregated into 8 different reconnection profiles with varying delay times (60 – 100s until reconnection) and ramp rates (0.5 – 10s to ramp up to 1pu generation) based on inverter bench testing by UNSW. • The remaining 2015 standard inverters were modelled to reconnect following frequency returning to above their assumed trip frequency and below 50.15 Hz for 90s, then ramping up with a six minute ramp rate as per the required behaviour under the 2015 standard.

[63] Further information on the data behind assumptions in modelling DPV behaviour can be found in Tables 7 and 8 in AEMO's report on Behaviour of distributed resources during power system disturbances (May 2021), https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf.

Variable	Description	Representation in model
PFR response – synchronous units	PFR is the inherent droop response from generators on the system to locally measured frequency. The Mandatory PFR rule change now requires plant to provide as much response as technically capable while frequency is outside their deadband. PFR will aid the initial arrest in frequency, but due to its proportional nature, will withdraw response as frequency begins to recover (moving back along its droop curve). Impact is limited by the technical capabilities of the plant including amount of available headroom or footroom.	Included: • Synchronous generator governor models aligned with PFR requirements, with FCAS trapeziums used as a proxy for likely PFR response. Included in frequency recovery models: • Modelled using generic governor models with parameters tuned in PSSE to represent governor behaviour of each generating unit under mandatory PFR. • Gas turbines were modelled using IEEEG1SDU model and Steam turbines were modelled using GGOV1DU model. Any plants without specific parameters were modelled with a simplified governor model with 4% droop. • Technical capability limits on PFR were assumed based on unit ramp rates and FCAS trapeziums.
PFR - Semi-scheduled wind		Included: • Modelled as an aggregate 5% droop model with no response to under frequency events (anticipating they are already generating at their maximum level and have no further headroom available) • Assumed capable of a 50% reduction in output Included in frequency recovery models: • Modelled as an aggregate 5% droop model with no response to under frequency events (anticipating they are already generating at their maximum level and have no further headroom available), but up to 50% footroom is available with a 3 s response time to respond to overfrequency events based on unit GPS requirements. • Applied to 30% of total wind generation in South Australia expected to have capability.
PFR - Semi-scheduled solar		Included: • Modelled as an aggregate 5% droop model with no response to under frequency events (anticipating they are already generating at their maximum level and have no further headroom available) • Assumed capable of a 50% reduction in output Included in frequency recovery models: • Modelled as an aggregate 4% over frequency droop and response time of 1.5 s with no response to under frequency events. Proportional reduction from 51 Hz which is held until frequency recovers below 50.15 Hz. Assumed capable of a 50% reduction in output in line with GPS requirements.
PFR - Scheduled IBR (Batteries)		Included: • Modelled as a 1.7% droop[64] function with limiters for headroom and footroom as applicable, responding to a disturbance within 200ms. • Deadbands are modelled at +/-0.015Hz. • Assumed 150 MW headroom and 120 MW of footroom available with sufficient energy to respond for at least the 10 minutes simulation timeframe, in line with historical availability. Other headroom sensitivities are outlined in Section 7.9.2.
Load relief	Change in load that occurs when power system frequency changes	• Assumed to be 0%, in line with common practice for planning studies[65]
Separation points	Points in the network between South Australia and South-West Victoria which may disconnect and separate	Included in frequency containment models: • Points [1] through to [5] Included in frequency recovery models: • Point [1] (separation at other points assumed to have similar response)

[64] Review of generator settings found that battery resources exhibit a faster response than other IBR with a 1.7% droop setting.

[65] AEMO notes that a load relief value of 0.5% is applied for FCAS purposes in the NEM mainland at present. However, an assumption of 0% is considered appropriate for system security studies. https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/load-relief

Variable	Description	Representation in model
Generator disconnection post-separation	Assumptions regarding possible disconnection behaviour of generators in South Australia and South-West Victoria	Included in frequency containment models • Pelican Point (PPCCGT) GTs may trip following high RoCoF (Section A2.3.2) • Lake Bonney 1-3 Wind Farm and Canunda Wind Farm trip 200ms after separation at points [1] through to [5] • Dundonnell Wind Farm and Stockyard Hill Wind Farm trip 170ms after separation at points [4] and [5], due to the action of the South-West Victoria Generator Fast Trip (SWV GFT) scheme
Large net demand variations	Net demand is that demand that needs to be met by Scheduled Generation. Following a separation, it may take 10-15 minutes for constraint invocation in NEMDE to dispatch Heywood down to 0MW. Prior to this, net demand ramps will need to be met by the automatic responses of resources within SA.	Sensitivity in frequency recovery studies: • Modelled as an extreme sensitivity to the base case to determine potential impact of having a coincidental worst case demand event. Two sensitivities were tested, one using a linear net demand ramp of 105 MW over ten minutes, and one using a 12 MW square load variation at 0.012 Hz.
Random net demand variation	On sub-five-minute timeframes, small deviations in demand can trigger “sizzle” in system frequency. These are usually managed through a combination of regulation FCAS and PFR.	Sensitivity in frequency recovery studies: • Included in the basecase as an ongoing four second statistical variation in load modelled using a white noise generator resulting in up to +/- 10 MW variation in system load.
AGC/ Regulation FCAS	Regulation FCAS is secondary frequency control dispatched by AGC used to manage frequency variation within five minute trading intervals. There are currently no regional requirements to have any level of Regulation FCAS within South Australia under system normal conditions. Immediately following separation, before AGC is reconfigured, setpoints sent to enabled Regulation FCAS services within SA in response to frequency measurements in NSW could either exacerbate or aid frequency recovery. The actual impact would depend on the dispatched services in SA and the frequency being measured in NSW following separation.	Sensitivity in frequency recovery studies: • Modelled as an extreme sensitivity to the base case to determine potential impact of having a coincidental worst case response from regulation FCAS providers in SA. • AGC setpoints based on historical snapshots are sent every four seconds to a regulation FCAS provider in the direction that would trigger a worse frequency recovery outcome. • Two sensitivities are conducted where the provider is dispatched for both Raise and Lower Regulation FCAS, and where the provider is dispatched for one or the other depending on the nature of the event.
Contingency FCAS	Contingency FCAS is local frequency control dispatched to manage the largest credible contingency in the NEM. There are currently no regional requirements to have any level of Contingency FCAS within South Australia under system normal conditions.	Excluded: • Excluded as contingency FCAS enablement levels in SA could be zero or low in many dispatch intervals due to having no regional requirements for FCAS enablement under a system normal condition.
NEMDE re-dispatch following separation	Central dispatch of generation to meet forecast demand levels for each five minute trading interval.	Excluded: • Excluded as NEMDE dispatch in real time following the event will be dependent on immediate system and market conditions following the event and therefore may assist or hinder frequency recovery. A neutral impact has been assumed.

A2. Risks associated with extreme RoCoF

AEMO has reviewed possible risks associated with extreme RoCoF in South Australia. This includes international literature reviews[66], commissioning a review of power system elements by GE[67], detailed interviews with other power system operators (especially EirGrid, who have extensively explored RoCoF withstand capabilities), engagement of consultants to conduct modelling of RoCoF withstand capabilities for specific units in South Australia, surveying the operators of a selection of the most significant units in South Australia to seek their insights on RoCoF withstand capabilities, and examining the behaviour of generating units in South Australia during historical frequency disturbances.

Despite considerable efforts, there remains much uncertainty over RoCoF withstand capabilities, and significant gaps in AEMO's knowledge and understanding of behaviour of the power system under high RoCoF conditions. AEMO's review to date suggests risks are likely primarily associated with the possible tripping of large synchronous generating units under extreme RoCoF conditions, outlined in more detail below. Otherwise, the analysis to date suggests that:

- Inverter-based generation generally can ride through extreme RoCoF (up to and exceeding ±4 Hz/s), except for a few older windfarms in South Australia that have specific RoCoF protection enabled.
  - Two wind farms in South Australia (with approximately 150 MW of generation capacity in total) have existing anti-islanding protection settings that trip the generators if RoCoF exceeds ±1 Hz/s for more than one second. These protection settings have been modelled in all studies in this report.
  - All other inverter-based generation in South Australia has been assumed to ride through extreme RoCoF events.
- Available evidence suggests that the tripping of distributed resources in response to extreme RoCoF is likely to be minimal in the NEM[68] (although this has been an issue of considerable concern in some international power systems). For this analysis, distributed resources have been assumed to successfully ride-through extreme RoCoF. Known under-frequency and over-frequency trip settings on distributed PV have been included in the model[69].
- UFLS schemes will not successfully contain frequency under extreme RoCoF conditions. This has been explicitly accounted for in the models applied in this analysis, based on the UFLS settings applied at present in South Australia.

Further details are provided in AEMO's submission to the 2022 review of the Frequency Operating Standard[70].

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[66] DGA Consulting (October 2016) International Review of Frequency Control Adaptation, Section 3 – Experiences with high RoCoF, https://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS-International-Review-of-Frequency-Control.pdf.

[67] GE Energy Consulting 2017, *Advisory on Equipment Limits associated with High RoCoF*, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/20170904-GE-RoCoF-Advisory.

[68] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, Section 3.2.2, https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[69] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, Section 3.1 https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[70] AEMO (December 2022), AEMO Advice: Reliability Panel Review of Frequency Operating Standard, Section 3, https://www.aemc.gov.au/sites/default/files/2022-12/AEMO%20FOS%20advice%20to%20the%20Reliability%20Panel%20FINAL%20for%20Publishing%2022 1205.pdf.

A2.1 Synchronous generating units – RoCoF withstand capabilities

The findings from AEMO's review on RoCoF withstand capabilities of synchronous generating units are as follows:

- Generally, large synchronous generating units can be anticipated to successfully ride-through disturbances up to 1 Hz/s (with some exceptions), but many demonstrate a range of issues for disturbances at 2 Hz/s.
- Significant risks were identified of:
  - Gas-fired generation tripping due to compressor surge on high negative RoCoF (rapidly dropping frequency), such as might occur following a non-credible separation event. Risk is highest at high or maximum power output, for extremes of ambient temperature, and for large industrial frame gas turbines.
  - Gas-fired generation tripping due to lean blow out (LBO) on high positive RoCoF (rapidly rising frequency), such as might occur after substantial (excessive) load shedding or non-credible separation events. There is also some risk associated with possible high positive RoCoF that accompanies the successful recovery of frequency from the nadir following a loss of generation or loss of an interconnector when exporting from a region.
- For all synchronous units, potential for misbehaviour of power system stabilisers, especially those which calculate accelerating power.
- Vulnerability to RoCoF differs significantly between units. In general, the highest RoCoF vulnerabilities are identified for units with higher inertia, particularly in electrically remote locations, and particularly for gas-fired units.
- Vulnerability to RoCoF can depend on how the unit is operating. Modelling suggests that RoCoF ride-through capabilities may be reduced when units operate at higher power setpoints, and when operating with an under-excited (leading) power factor.
- RoCoF capability is generally diminished where there are co-incident voltage events.

A2.2 Historical events

Historical events give an indication of the RoCoF ride-through capabilities of specific generating units in the power system. However, extreme RoCoF events are relatively rare, units must be operating at the time of the disturbance to give an indication of their capabilities, and RoCoF withstand abilities can vary depending on how the unit is operating at the time of the disturbance. The available data is therefore limited.

Table 47 lists all significant high RoCoF events recorded in South Australia since 2004, the units that were online at the time, and the observed response of these units. Only two of these past events exceeded -2 Hz/s (300 ms average).

Table 47 Historical extreme RoCoF events

Date	Event	AEMO reported max RoCoF (500 ms avg)	Max RoCoF near generator terminal (300 ms avg)	Min SA freq	Synchronous generator ride-through	
					Successful	Unsuccessful
2004-03-08	Non-credible separation	-2.1 Hz/s	-2.4 Hz/s	47.6 Hz	• Torrens B1, B3, B4 • Osborne GT + ST	• Ladbroke
2005-03-14	Non-credible separation	-1.6 Hz/s	-2.3 Hz/s	47.6 Hz	• Torrens B2, B3, B4 • Osborne GT + ST	• Pelican Point GT + ST • Ladbroke
2012-06-19	Earthquake	-0.42 Hz/s, +0.13 Hz/s		49.2 Hz	• Torrens B3, B4 • Pelican Point GT + ST	• Torrens A4
2016-09-28	Black system	-6.25 Hz/s (over 400 ms)		-	Not applicable – All units disconnected due to system black Torrens B1, B3, B4 and Ladbroke 1, 2 were online pre-event.	
2016-12-01	Credible separation	-1.2 Hz/s	-1.7 Hz/s	48.2 Hz	• Torrens B2, B3, B4 • Pelican Point GT + ST • Quarantine	-
2018-08-25	Non-credible separation	+0.65 Hz/s		49.15 Hz	• Torrens A3, B1, B2, B3, B4 • Osborne GT + ST • Pelican Point GT + ST	-
2019-11-16	Non-credible separation	+1.2 Hz/s		49.8 Hz	• Torrens B3, B4 • Osborne GT + ST • Pelican Point GT + ST	-
2020-01-31	Non-credible separation	+0.8 Hz/s		50 Hz	• Torrens A1, A2, A4, B1, B2, B3 • Osborne GT + ST • Pelican Point GT + ST • Quarantine 1, 5	-

Observations for the large South Australian gas generators units online during these high RoCoF events are summarised in Table 48. Some mechanisms of failure have been observed historically. In the -2.4 Hz/s event (2004) and the -2.3 Hz/s event (2005), Ladbroke Grove PS (80 MW peaking plant) tripped on activation of distance protection. The unit also showed possible signs of pole slipping in the -2.4 Hz/s event, demonstrating that vulnerabilities have been observed in some units in these RoCoF ranges. Subsequent control replacement and implementation of PSS tuning at Ladbroke Grove PS has improved overall performance of the power station, meaning pole slip is unlikely to be observed at the unit in future.

Table 48 Observations for South Australian frequently operating gas generators during high RoCoF events

Power station	Observations in historical events
Torrens Island B	• Have observed successful withstand of -1.7 Hz/s (2016), -2.3 Hz/s (2005), and -2.4 Hz/s (2004) (300 ms average).
Osborne	• Have observed successful withstand of -1.7 Hz/s (2016), -2.3 Hz/s (2005), and -2.4 Hz/s (2004) (300 ms average).

Power station	Observations in historical events
Pelican Point (PPCCGT)	• PPCCGT ST+1 x GT have demonstrated successful withstand of -1.7 Hz/s (2016) at a capacity factor of approximately 0.5.[71]. • Not online in -2.4 Hz/s event (2004). • PPCCGT ST+1 x GT tripped during -2.3 Hz/s event (2005) when at a capacity factor of 0.5, due to an error in the digital control systems that controlled the GT dynamic response. Unstable combustion and flameout tripped the GT, and the ST then tripped on falling steam pressure. A correction to the digital control system was implemented on 25 April 2005. The error was only apparent for a relatively large frequency disturbance with high RoCoF, which has not been seen again since, so the behaviour of the unit subsequent to this update remains unknown.
Quarantine	• Have observed successful withstand of -1.7 Hz/s (2016). • Not online in -2.3 Hz/s event (2005), or -2.4 Hz/s event (2004).
Barker Inlet	• Have not observed high negative RoCoF events since the unit was commissioned late 2019. • As part of its connection process, the unit has met recent access requirements for RoCoF. • Risks associated with South Australian non-credible separation events are substantially lower if generators can ride through at least ±2 Hz/s for 250 ms. Barker Inlet's Generator Performance Standards indicate the unit is capable of riding through RoCoFs in this range.

ST: Steam turbine, GT: gas turbine.

A2.3 Assumptions on RoCoF withstand applied for synchronous units

A2.3.1 Torrens Island B and Osborne Power Station

Torrens Island B and Osborne Power Station operate frequently and are therefore influential. For these units, based on their observed successful withstand of -1.7Hz/s (2016), -2.3Hz/s (2005), and -2.4Hz/s (2004), it is considered reasonable to assume withstand capabilities up to and including -2Hz/s (300ms average). For these units, no RoCoF vulnerabilities have been modelled (implicitly assuming they can withstand any level of extreme RoCoF observed in these studies).

A2.3.2 Pelican Point Power Station (PPCCGT)

PPCCGT operates often (more than 70% of the time in 2021-22) and has a large capacity and high inertia. A possible trip of PPCCGT is therefore highly influential in a South Australian island following a non-credible separation event, particularly when the unit is operating at high levels (when studies suggest it is likely to be most vulnerable to extreme RoCoF).

Furthermore, PPCCGT consists of gas-fired units (2 x GTs + 1 x ST). AEMO's review has indicated GTs are the most vulnerable to extreme RoCoF, and PPCCGT is also a very high inertia unit, which further increases RoCoF vulnerability.

AEMO has engaged with the station operator, who has requested information from the OEMs, but to date this has not provided any further insight on likely RoCoF withstand capabilities of these units.

AEMO therefore proposes that the available evidence indicates a meaningful risk that the PPCCGT GTs could trip following an extreme RoCoF event[72], and that this could have meaningful consequences in a significant

[71] AEMO (February 2017), *Final Report – South Australia Separation Event, 1 December 2016*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2017/final-report---sa-separation-event-1-december-2016.pdf?la=en&hash=E38712992D459AFA19421E48925A4B7D.

[72] With a resultant trip of the ST following loss of steam from the GTs. This typically occurs 40-75 seconds after the trip of the GTs.

proportion of periods. The exact level at which tripping could occur is unknown. For this analysis, AEMO has assumed the following:

- **Base assumption** – if RoCoF exceeds ±2 Hz/s for >100 ms, the PPCCGT GTs trip. The steam turbine (ST) is assumed to disconnect 40 seconds after the gas turbines (GTs) due to the loss of steam[73].
- **Sensitivity 1 –** PPCCGT GTs trip if RoCoF exceeds ±2 Hz/s for >250 ms. The ST disconnects 40 seconds after the GTs due to the loss of steam.
- **Sensitivity 2 –** PPCCGT remains connected and successfully rides through high RoCoF.

The incidence and scale of risks are based on the base case RoCoF withstand assumption for PPCCGT outlined above. If further information becomes available about the RoCoF withstand capabilities of synchronous generating units in the NEM, these studies will be reviewed.

A2.3.3 Other synchronous units in South Australia

Other units in South Australia, including Ladbroke Grove and Quarantine, may have vulnerability to extreme RoCoF, but operate rarely, and have relatively smaller capacity and inertia (meaning that a possible trip of these units will have less impact on the South Australian island). The possible impact of RoCoF vulnerability of these units has therefore not been explicitly explored in this analysis.

[73] As the PPCCGT ST runs on steam from the GTs, the ST typically trips within 40-75 seconds following a trip of the GT (as the ST runs out of steam). The exact time at which the ST trips may vary depending on station operating conditions, the non-credible contingency, and the RoCoF trip mechanism. In 2005, when PPCCGT tripped in the 2005 high RoCoF event, the ST disconnected after the GT within approximately 40 – 75 seconds.

A3. PSS®E and PSCAD studies

A3.1 Strengths and limitations of the Multi-Mass Model

A3.1.1 Strengths of the MMM

The majority of the analysis presented in this report is based on simulations in a Matlab/Simulink MMM. This model calculates frequency in South Australia and South-West Victoria based on an Equation of Motion (energy balance). It is a relatively simple model, appropriate for modelling relatively simple frequency events, and for studying the behaviour of UFLS when there are no other complicating factors.

The relative simplicity of the model allows explicit analysis of many dispatch scenarios, which is helpful when developing cost/benefit assessments where outcomes over a range of periods need to be assessed probabilistically (rather than just examining outcomes in worst-case periods).

It is also valuable to have the flexibility to rapidly model many dispatch scenarios where the “worst case” dispatch conditions are not necessarily obvious. This is the case when studying the impacts of DPV on UFLS functionality, where the worst outcomes often arise in moderate DPV generation conditions where UFLS functionality is reduced, but very large non-credible contingency events are plausible.

For these reasons, the MMM has been applied as the main model used for the studies in this report.

A3.1.2 Limitations of the MMM

As with all models, the MMM has limitations. The MMM does not include any explicit representation of power system voltages or system strength. It also does not include any explicit representation of the topology of the network, with all generation and load “lumped” at a single bus representing the whole region.

This means that the MMM is limited in the ability to model:

- Voltage effects (for example, any factors that may lead to voltage collapse, or effects where voltage changes may lead to operation of various protection or control schemes).
- System strength effects.
- Oscillatory, voltage or transient stability effects.
- Variation in frequency at different buses in the network (in the transient period immediately following a fault, the measured frequency may vary at different buses in the network).
- Frequency transients (short duration changes to the waveform that can be measured as rapid and potentially severe changes in frequency in the first ~500ms following a disturbance).

It is important to understand which situations may experience these effects, so they can be properly accounted for in the design of management measures. For example, intervention to manage factors that cause frequency to fall below 47 Hz (based on MMM outcomes) may not be warranted if the power system is likely to experience a voltage collapse or other types of stability issues regardless under those conditions, which may require additional intervention.

The MMM was hence tuned against a selection of PSS®E studies to determine if these complicating factors were likely to occur in scenarios modelled in this report. Frequency outcomes in the MMM and PSS®E studies were then examined and benchmarked.

PSS®E snapshots are time-consuming to prepare and tune, and simulation times are much longer than the MMM, meaning studies can only be conducted for a small selection of periods and dispatch conditions. Selected studies conducted in PSS®E to analyse South Australian non-credible separation events have therefore been compared against the MMM, aiming to provide increased confidence of the conditions where the MMM provides an adequate and suitable representation of the important power system dynamics, and develop proxies where necessary to suitably represent the triggering of various relevant control schemes.

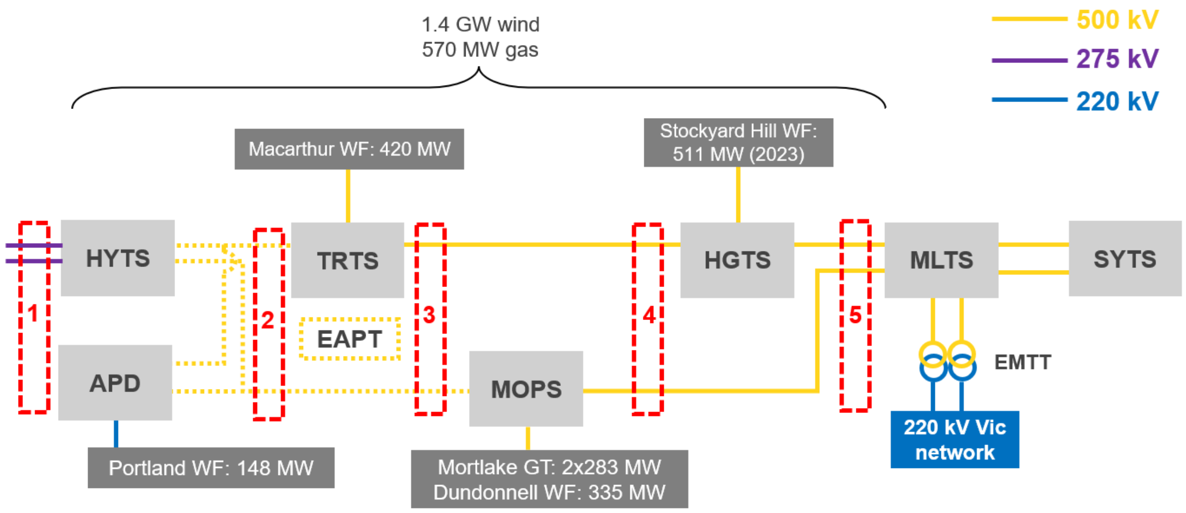
PSS®E models also have important limitations, since they cannot capture system strength effects and are not appropriate for modelling conditions of low fault levels. To capture these possible effects, PSCAD studies must be conducted. PSCAD snapshots are even more time consuming to prepare, and simulation times are even longer, meaning that only a very small handful of studies can be conducted, in a very small subset of conditions. These studies can be used as a confirmation of outcomes in boundary conditions. A very small collection of PSCAD studies have been conducted to examine non-credible South Australian separation events, summarised in the sections below.

Due to the time-consuming nature of preparing and running PSS®E and PSCAD studies, it will never be possible to comprehensively study every possible scenario. This section summarises what is understood based on the studies that have been conducted at the present time. As further work continues, new evidence may become available.

A3.2 Summary of benchmarking against PSS®E and PSCAD

The key findings from PSS®E and PSCAD studies of separations at points [1] to [5] (shown in Figure 64 for reference) are summarised in Table 49.

Figure 64 South Australia separation points studied in this analysis, numbered [1] to [5]



[1]: Heywood - South East (HYTS - SESS) 275 kilovolt (kV) lines.
[2]: Heywood – Alcoa Portland - Mortlake (HYTS - APD - MOPS) 500 kV line and Heywood - APD - Tarrone (HYTS - APD - TRTS) 500 kV line.
[3]: Heywood - APD - Mortlake (HYTS - APD - MOPS) 500 kV line and Tarrone - Haunted Gully (TRTS - HGTS) 500 kV line.
[4]: Tarrone - Haunted Gully (TRTS - HGTS) 500kV line and Mortlake - Moorabool (MOPS - MLTS) 500 kV line.
[5]: Moorabool - Haunted Gully (MLTS - HGTS) 500 kV line and Moorabool - Mortlake (MLTS -MOPS) 500 kV line.

WF: Wind farm
GT: Gas turbine

Table 49 Summary of benchmarking of MMM against PSS®E and PSCAD studies

Separation point	SA frequency	RoCoF	Studies conducted	Complicating factors observed in PSS®E / PSCAD	How complicating factors have been addressed
[1] or [2]	Under-frequency	All	PSS®E	None observed	NA – MMM provides a good representation
	Over-frequency	All	PSS®E & PSCAD	Instability on QNI when QNI is exporting to New South Wales near limits	Out of scope for this analysis
[3], [4] or [5]	Under-frequency	Mild (<-2 Hz/s)	PSS®E & PSCAD	None observed	NA – MMM provides a good representation
		Severe (>-2 Hz/s)	PSS®E & PSCAD	Frequency transients trigger EAPT	RoCoF proxy for EAPT operation implemented in MMM to capture EAPT triggers
	Over-frequency	Mild (<+2 Hz/s)	PSS®E	Instability on QNI observed when QNI is near export limits (Queensland to New South Wales)	Out of scope for this analysis
		Severe (>+ 2Hz/s)	PSS®E	• Instability on QNI observed when QNI is near export limits (Queensland to New South Wales) • High RoCoF can lead to system instability due to very high frequency in Victoria under some conditions	

Where there are no complicating factors beyond simple frequency dynamics observed in the PSS®E or PSCAD studies, the MMM is considered likely to provide a reasonable representation of the important power system dynamics. This is the case for all studies conducted on separation events at [1] or [2] leading to under-frequency in South Australia, and also for milder under-frequency separation events at [3], [4] or [5].

In some cases (such as more severe separations at [3], [4] or [5] leading to under-frequency in South Australia), some complicating factors were observed, but it was possible to develop proxies to represent these adequately in the MMM. This proxy approach is believed to provide a reasonable representation of the observed effects in the MMM, such that the MMM continues to capture the important power system dynamics in these cases, with the proxies applied.

In other cases (such as separation events leading to over-frequency in South Australia), there are more complex factors observed in PSS®E and PSCAD studies which could not be adequately represented in the MMM. These scenarios are considered out of scope for this analysis. Further study is required in these cases to properly understand power system dynamics and develop suitable management measures.

A3.3 Separation at [1] or [2]

A3.3.1 Under-frequency in South Australia

Eleven historical case studies were modelled in PSS®E examining separation at [1] under conditions of South Australian import on the Heywood Interconnector (leading to under-frequency in South Australia)[74,75].

Cases were selected based on high Heywood interconnector import levels. Case details are given in Table 50, and outcomes are given in Table 51.

For all eleven case studies leading to under-frequency in South Australia, the case was found to be stable, and there was no evidence of voltage collapse or any other factors not accounted for in the MMM. Some cases showed insufficient UFLS action to arrest the frequency nadir above 48Hz (cases 1 and 11), and some cases showed issues related to frequency recovery (frequency settling around 49.4Hz in cases 1, 6 and 11). These factors are well represented in the MMM, and have therefore been accounted for in the studies included in this report.

Table 50 Separation at [1] under-frequency in South Australia – historical case studies in 2022 PSFRR

Case	SA operational demand (MW)	Total import (Heywood + Murraylink) (MW)	Heywood import (MW)	SA inertia (MWs)	SA underlying UFLS load (MW)	SA DPV (MW)	SA renewables (MW)
1	1146	693	678	9805	1180	535	140
2	2070	834	587	14157	2264	796	313
3	2279	853	556	17376	2231	603	178
4	2360	765	541	20787	2401	696	243
5	1663	754	538	12165	2014	953	548
6	1737	819	581	14034	2071	943	534
7	1594	651	474	12165	1971	956	583
8	2295	812	618	20870	2348	728	282
9	1889	690	549	14034	2220	854	419
10	2304	756	589	17862	2261	549	172

74 AEMO (July 2022), *Power System Frequency Risk Review*, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

75 AEMO (July 2022) *Power System Frequency Risk Review* – Appendices, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review---appendices.pdf?la=en.

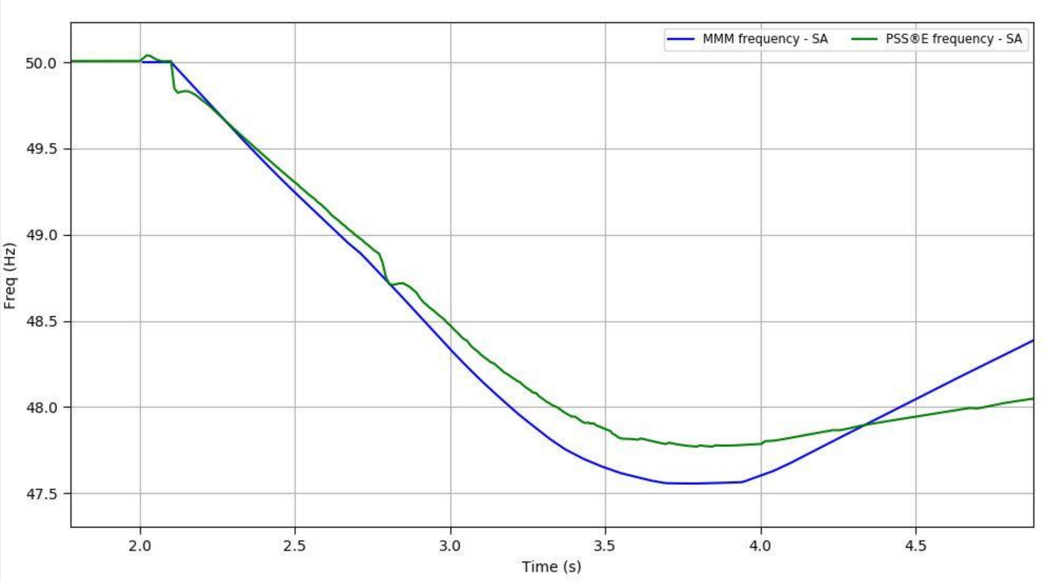
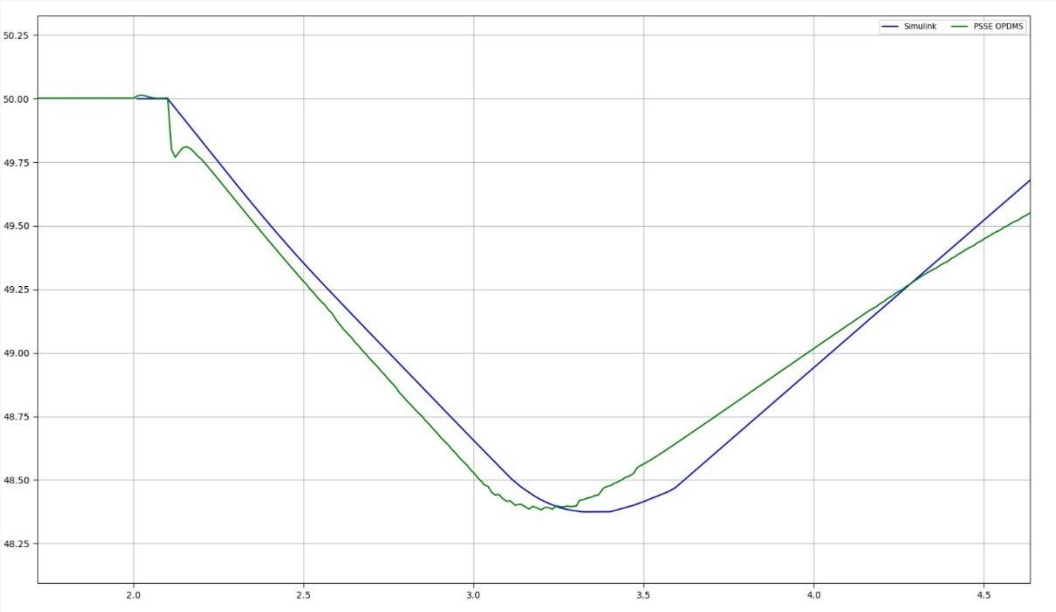
Case	SA operational demand (MW)	Total import (Heywood + Murraylink) (MW)	Heywood import (MW)	SA inertia (MWs)	SA underlying UFLS load (MW)	SA DPV (MW)	SA renewables (MW)
11	1112	672	575	9805	1090	465	228

Table 51 Separation at [1] leading to under-frequency in South Australia – outcomes for historical case studies in 2022 PSFRR

Case	SA frequency nadir (Hz)	SA RoCoF (Hz/s)	SA underlying UFLS load tripped (MW)	SA % Total DPV tripped	Was the case stable? (Yes/No)
1	47.8	1.32	887	71	Yes
2	48.6	0.89	676	25	Yes
3	48.7	0.79	689	25	Yes
4	48.8	0.82	591	19	Yes
5	48.6	0.87	749	31	Yes
6	48.6	1.50	748	31	Yes
7	48.6	0.64	599	25	Yes
8	48.7	0.72	714	25	Yes
9	48.6	0.79	668	25	Yes
10	48.7	0.82	676	25	Yes
11	48.0	1.15	731	64	Yes

Figure 65 illustrates some benchmarking studies for a separation at [1] leading to under-frequency in South Australia, explicitly comparing MMM outputs against PSS®E studies. For both cases, the MMM shows a good match to PSS®E, and there were no further complicating factors observed which were not accounted for in the MMM.

Figure 65 Benchmarking – MMM vs PSS®E – separation at [1] leading to under-frequency in South Australia

Heywood import into South Australia (MW)	Frequency profiles: Blue – MMM frequency - SA Green – PSSE®E frequency - SA
575 MW	
500 MW	

These PSS®E studies suggest that the MMM provides a suitable representation of power system dynamics for separations at [1] or [2] leading to under-frequency in South Australia.

A3.3.2 Over-frequency in South Australia

Twelve historical case studies were modelled in PSS®E examining separation at [1] under conditions of South Australian export on the Heywood Interconnector (leading to over-frequency in South Australia)[76,77]. Cases were selected based on high Heywood Interconnector exports from South Australia. Case details are given in Table 52, and outcomes are given in Table 53.

All cases were stable except for Case 11, where QNI was found to become unstable following separation at [1]. This case involved high exports from South Australia in addition to QNI exporting large amounts of energy (1,048 MW) from Queensland to New South Wales. This effect cannot be satisfactorily incorporated into the MMM. For this reason, separation events leading to over-frequency in South Australia are considered out of scope for this analysis. Further study is required.

Table 52 Separation at [1] over-frequency in South Australia – historical case studies

Case	SA operational demand (MW)	Total export (HIC + Murraylink) (MW)	HIC export (MW)	SA inertia (MWs)	SA underlying UFLS load (MW)	SA available OFGS (MW)	SA DPV (MW)	SA renewables (MW)
1	504	585	459	9527	967	506	865	575
2	477	628	460	9805	1058	357	945	694
3	520	602	454	9805	1042	388	908	759
4	647	777	543	10705	1064	605	739	932
5	747	697	556	10893	969	661	540	948
6	652	725	580	10705	1040	585	716	884
7	723	691	581	9805	1094	571	788	829
9	1034	790	573	11674	1133	642	520	976
10	1562	766	648	18043	1726	723	680	875
11	1611	832	638	18043	1777	671	699	852
12	1306	672	558	15729	1307	687	580	915
13	1205	574	448	14829	1366	627	724	811

Table 53 Separation at [1] over-frequency in South Australia – outcomes for historical case studies

Case	SA frequency peak (Hz)	SA RoCoF (Hz/s)	SA OFGS generation tripped (MW)	Total DPV tripped on protection only (MW)
1	51.0	0.78	13	98
2	51.0	0.77	9	94
3	51.0	0.77	8	83
4	51.2	0.83	15	76
5	51.1	0.86	20	55
6	51.2	0.87	15	93

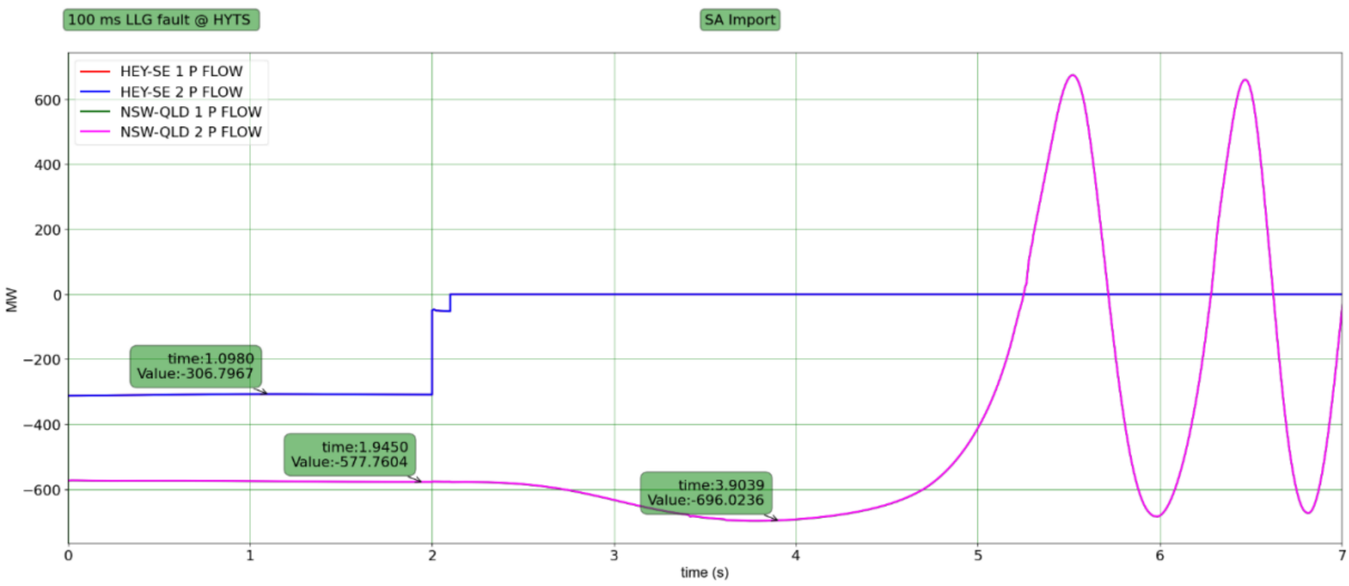
[76] AEMO 2022, *Power System Frequency Risk Review*, available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

[77] AEMO (July 2022) Power System Frequency Risk Review – Appendices, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review---appendices.pdf?la=en

Case	SA frequency peak (Hz)	SA RoCoF (Hz/s)	SA OFGS generation tripped (MW)	Total DPV tripped on protection only (MW)
7	51.2	0.90	14	96
9	51.1	0.82	16	56
10	51.1	0.69	22	67
11	51.2	0.67	21	69
12	51.0	0.65	15	59
13	51.0	0.57	0	67

Figure 66 shows interconnector flows from Case 11. Following South Australia separation, QNI loses stability, leading to the separation of Queensland from the rest of the NEM, resulting in three islands being formed (South Australia, Victoria/New South Wales, and Queensland). Further study is required to determine the scenarios where this risk arises, and appropriate management measures. For this reason, separation events leading to over-frequency in South Australia are considered out of scope for this analysis.

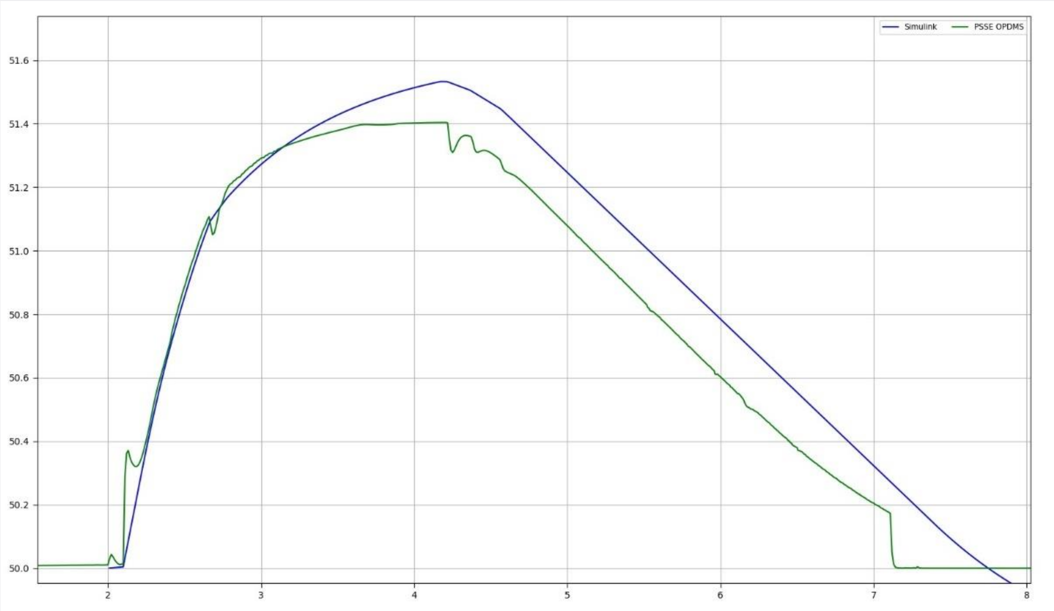
Figure 66 Case 11 – Separation at [1], showing Heywood Interconnector flows (blue) and QNI flows (pink)



Note: Heywood (HEY-SE) and QNI (NSW-QLD) are double circuit interconnectors. Only one circuit has been shown in the figure. Power flow on the second circuit of each interconnector is very similar.

Figure 67 shows an example case study, explicitly benchmarking the MMM against a separation at [1] leading to over-frequency in South Australia. In this case, where there is no instability observed on QNI, the MMM provides a good match to the PSS®E study outcomes.

Figure 67 Benchmarking – MMM vs PSS®E – separation at [1] or [2] leading to over-frequency in South Australia

Heywood import into South Australia (MW)	Frequency profiles: Blue – MMM frequency - SA Green – PSSE®E frequency - SA
-580 MW (export from SA -> Vic)	

Studies on non-credible separation events leading to over-frequency in South Australia were also conducted as part of a review of the OFGS scheme in South Australia. These studies examined separation events at [1] with up to 700 MW export from South Australia to Victoria, including sensitivities with 0, 1, or 2 gas turbines operating in South Australia, and exploring the implications of an APD disconnection (which can occur during voltage disturbances). The studies indicate that in periods with high levels of DPV operating, outcomes can be sensitive to the voltage response of DPV, which is uncertain. This is noted as an area for further analysis. Otherwise, no further complicating factors were observed that are not represented in the MMM.

PSCAD studies

A selected study to examine a separation event at [1] leading to over-frequency in South Australia was conducted in PSCAD as part of the OFGS review to validate the PSS®E model and examine boundary conditions. The case was run at low demand, low inertia and night-time (no DPV) conditions. No additional complicating factors were observed.

A3.3.3 Separation at [1] or [2] – summary

The selected studies that have been conducted in PSS®E and PSCAD suggest that the MMM provides a reasonably accurate representation of average power system frequency for separations at [1] or [2] that lead to an under-frequency condition in South Australia. Separations at [1] or [2] leading to over-frequency may have additional complicating factors that are not accounted for in the MMM, and are considered out of scope for this report.

A3.4 Separation at [3], [4] or [5]

A3.4.1 Under-frequency in South Australia

Ten historical case studies were modelled in PSS®E examining separation at [5] under conditions of South Australian import on the Heywood Interconnector (leading to under-frequency in South Australia) [78,79]. Cases were selected based on high Heywood interconnector import levels. Case details are given in Table 54, and outcomes are given in Table 55.

Table 54 Separation at [5] under-frequency in South Australia – historical case studies

Case	SA operational demand (MW)	Total import (HIC + Murraylink) (MW)	HIC import (MW)	SA Inertia (MWs)	SA underlying UFLS load (MW)	SA DPV (MW)	SA renewables (MW)
1	1066	693	678	9805	1180	535	140
2	1255	846	587	9805	843	0	53
3	1122	858	589	9805	936	240	121
4	1180	850	585	9805	789	0	63
8	1028	835	552	9805	651	0	23
9	2476	551	615	20344	2106	215	175
10	2121	616	514	18182	1646	0	147
11	2338	566	472	21038	2405	648	321
12	2411	570	492	20602	2448	618	365
13	2355	529	437	20668	1943	0	160

Table 55 Separation at [5] under-frequency in South Australia – outcomes for historical case studies

Case	SA freq nadir range (Hz)	SA RoCoF (Hz/s)	SA underlying UFLS load tripped (MW)	SA % total DPV tripped	Heywood trip due to control scheme operation	Was the case stable? (Yes/No)
1	47.8	1.34	887	71	Yes	Yes
2	48.2	1.53	413	0	Yes	Yes
3	48.1	1.71	567	59	Yes	Yes
4	48.2	1.51	398	0	Yes	Yes
8	48.1	1.62	389	0	Yes	Yes
9	48.9	0.46	182	6		Yes
10	49.0	0.55	97	0		Yes
11	49.0	0.32	140	4		Yes
12	48.9	0.34	144	4		Yes
13	49.7	0.20	0	0		Yes

Cases 9 to 13 all had low RoCoF (<1 Hz/s, 300 ms average) and did not show any instability, control scheme operation or other unusual behaviour. For these cases, the MMM provides a reasonable representation of the

[78] AEMO 2022, *Power System Frequency Risk Review*, available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

[79] AEMO (July 2022) Power System Frequency Risk Review – Appendices, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review---appendices.pdf?la=en

South Australian frequency nadir and South Australian RoCoF. In Cases 1, 2, 3, 4 and 8, where RoCoFs were relatively higher, control schemes operated to separate South Australia at Heywood[80]. The EAPT model used in the 2022 PSFRR historical case studies was based on the historical scheme, which contained power swing criteria. These power swing criteria will be replaced by topological criteria in the incoming EAPT upgrade[81].

EAPT can strongly influence frequency outcomes in South Australia. An upgrade to the EAPT is expected to be in place over the forecast period (2022-23 to 2023-24) and the MMM EAPT model was developed based on the incoming EAPT upgrade. As some EAPT performance criteria are not explicitly represented in the MMM (Appendix A3.1.2), benchmarking studies between PSS®E and the MMM were used to develop the MMM EAPT model and build MMM proxies to account for these factors. A RoCoF proxy was developed for the MMM EAPT Mode 1 model, and details on the benchmarking studies used to develop this proxy are found in Section A3.4.3.

As an illustrative benchmarking case, Figure 68 shows the PSS®E outcome for Case 1 from the 2022 PSFRR[82,83]. In this case, a control scheme operated shortly after the Moorabool separation to separate South Australia at Heywood. South Australian frequency fell to a nadir of 47.8 Hz, and the initial RoCoF was -2.3 Hz/s (100 ms average[84]).

Figure 68 Case 1, Separation at [5], showing Heywood Interconnector active (red) and reactive (blue) flows, and South Australian frequency

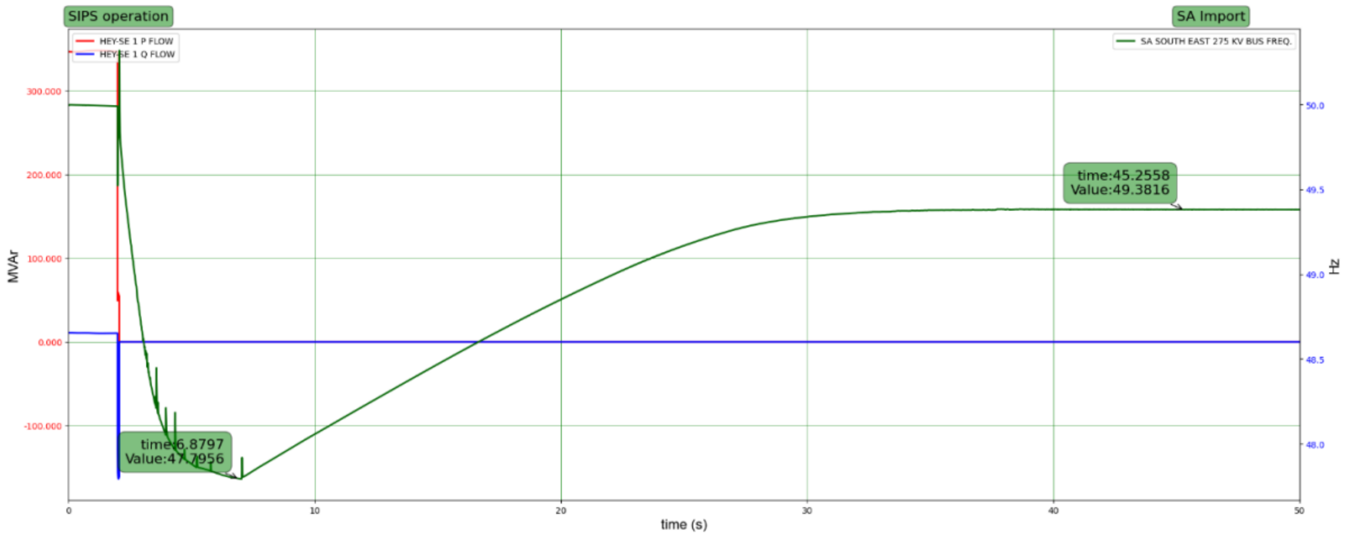


Figure 69 shows the South Australia frequency for this case, with the PSS®E outcome in blue and the MMM outcome (which includes the proxies used for the MMM EAPT model, outlined in Appendix A3.4.1) in dark green.

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80 In Case 1, PSS®E modelling from the 2022 PSFRR shows both SA SIPS Stage 3 and EAPT would have activated on very similar timeframes to separate South Australia at Heywood and produce a similar frequency result. ElectraNet has noted that SA SIPS Stage 3 activation following a separation in South-West Victoria is unexpected and that this requires further investigation.

81 AEMO (October 2021) *Victorian Annual Planning Report*, Section 4.7, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2021/2021-victorian-annual-planning-report.pdf?la=en.

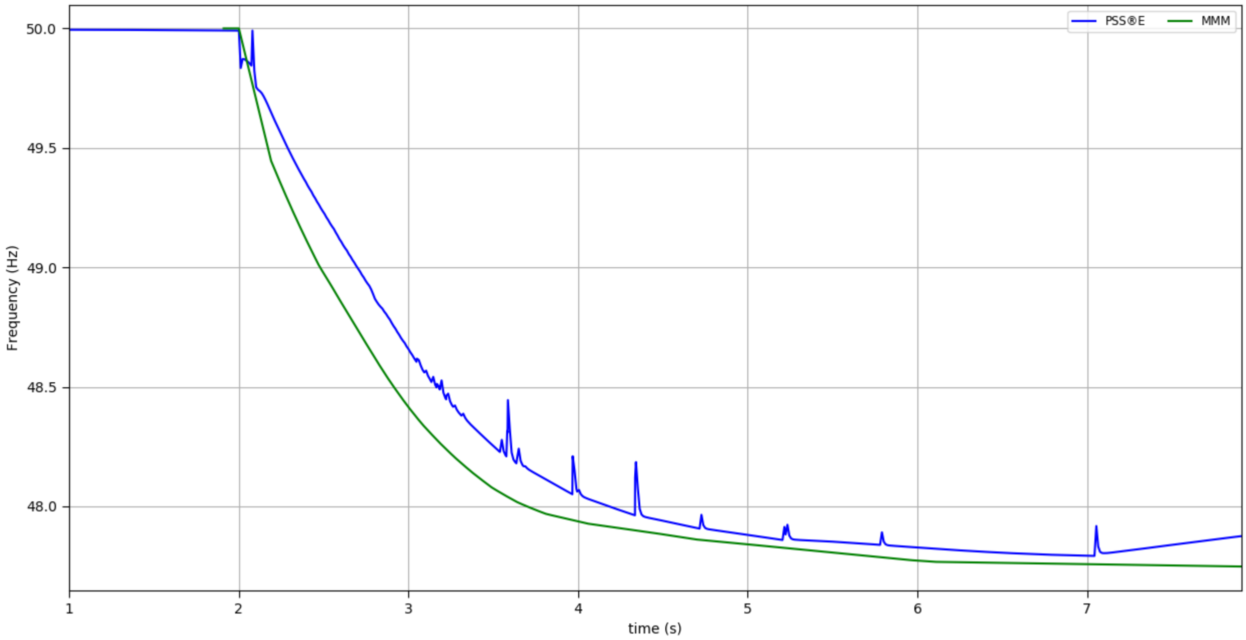
82 AEMO (July 2022) *Power System Frequency Risk Review,* https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

83 AEMO (July 2022) *Power System Frequency Risk Review* – Appendices, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review---appendices.pdf?la=en

84 As control schemes can operate within 200 ms, the typical 300 ms RoCoF averaging window would not produce meaningful results in this case.

The profiles show control schemes activating in both the MMM and PSS®E models to separate South Australia at Heywood, producing a similar frequency result.

Figure 69 Benchmarking – MMM vs PSS®E model from 2022 PSFRR: Case 1, historical case studies for a separation at [5] leading to under-frequency



These case studies demonstrate that with the proxies used in the MMM EAPT operation included, the MMM produces an adequate representation of the PSS®E study outcomes for separations at [5] that lead to an under-frequency in South Australia.

Summary

These studies suggest that the MMM provides a suitable representation of power system dynamics for separations at [3], [4] or [5] leading to under-frequency in South Australia, when a RoCoF proxy is applied to capture 'rapid' EAPT Mode 1 activation.

A3.4.2 Over-frequency in South Australia

Eleven historical case studies were modelled in PSS®E examining separation at [5] leading to over-frequency in South Australia[85,86]. Cases were selected based on high levels of export across the Heywood interconnector to Victoria. Case details are given in Table 56, and outcomes are given in Table 57.

All cases were stable except Cases 1 and 3, where QNI lost stability. In both cases, QNI was exporting energy from Queensland to New South Wales near its limits (1,206 MW and 1,299 MW for Case 1 and 3 respectively).

[85] AEMO (July 2022) *Power System Frequency Risk Review,* https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

[86] AEMO (July 2022) *Power System Frequency Risk Review* – Appendices, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review---appendices.pdf?la=en.

This QNI instability effect cannot be satisfactorily incorporated into the MMM. For this reason, separation events leading to over-frequency in South Australia are considered out of scope for this analysis. Further study is required to determine when these risks may arise, and develop suitable management measures.

Table 56 Separation at [5] over-frequency in South Australia – historical case studies

Case	SA operational demand (MW)	Total export (HIC + Murraylink) (MW)	HIC export (MW)	SA inertia (MWs)	SA underlying UFLS load (MW)	SA available OFGS (MW)	SA DPV (MW)	SA renewables (MW)
1	1774	630	560	18043	1855	749	723	949
2	805	644	529	13220	1080	115	798	345
3	1989	631	558	18036	1897	778	480	1011
4	1132	642	560	13134	1475	648	900	907
5	1856	580	525	22985	1689	138	465	310
6	852	551	535	14934	1087	106	758	296
7	1380	606	507	13264	938	722	0	860
8	1447	562	501	15729	1119	634	163	775
9	777	503	512	15624	1044	21	798	258
11	825	516	506	13220	1052	76	743	298
12	1013	632	527	14934	1063	75	554	210

Table 57 Separation at [5] over-frequency in South Australia – outcomes for historical case studies

Case	SA freq peak range (Hz)	SA RoCoF (Hz)	SA OFGS generation tripped (MW)	SA total DPV tripped on protection only (MW)
1	51.2	0.38	23	66
2	50.3	0.12	0	0
3	51.2	0.73	20	44
4	51.4	1.10	16	81
5	51.0	0.24	9	42
6	50.2	0.08	0	0
7	51.8	1.11	32	0
8	51.5	0.68	28	15
9	50.6	0.23	0	0
11	50.2	0.10	0	0
12	50.2	0.09	0	1

PSCAD studies

A selected study to examine a separation event at [5] leading to over-frequency in South Australia was conducted in PSCAD as part of the OFGS review to validate the PSS®E model and examine boundary conditions. The case was run at low demand, moderate inertia and night-time (no DPV) conditions, with both Mortlake GTs online. No additional complicating factors were observed.

A3.4.3 Emergency APD Potline Tripping (EAPT) MMM representation

Some EAPT performance criteria are not explicitly represented in the MMM (Appendix A3.1.2). Benchmarking studies between PSS®E and the MMM were used to develop the MMM EAPT model and build MMM proxies to account for these factors.

EAPT Mode 1 and Mode 2 are relevant to frequency outcomes following separations in the South-West Victoria network:

- **EAPT Mode 1** – if both topological and performance criteria are met, EAPT activates and separates South Australia at the 500 kV HYTS circuits.
  - **Topological criteria** – met if circuit breakers are open at various possible separation points in the South-West Victorian network.[87]
  - **Performance criteria** – met if frequency *or* voltage at specific locations in the South Australian network fall below these thresholds[88]:
    - Frequency performance criteria for EAPT operation – frequency on either SESS 275 kV line below 49.7 Hz.
    - Voltage performance criteria for EAPT operation – voltage on both HYTS 500 kV busbars below 80% of nominal for greater than 400 ms, indicating a severe voltage depression.
- **EAPT Mode 2** – if topological criteria are met (circuit breakers are detected to be open), EAPT activates to separate at the 500 kV HYTS circuits.

The EAPT scheme is designed to operate in Mode 1 normally and would be switched to Mode 2 only whenever separation at a location along the HYTS-MLTS 500 kV corridor becomes a credible event (for example, during prior outages of one of the 500 kV lines along the HYTS-MLTS corridor in South-West Victoria).

EAPT activation on frequency

In all PSS®E/MMM benchmarking case studies where EAPT activated, the frequency criteria were met first and triggered scheme activation. Case studies are shown in Figure 70. The red line indicates the MMM frequency outcome and green and dark blue lines indicate the PSS®E frequency at various locations in South Australia.

At the time that the MMM RoCoF proxy was developed, a PSS®E model for the upgraded EAPT scheme had not yet been completed. As such, the MMM RoCoF proxy was developed through extensive consultation with the EAPT scheme upgrade designers on the conditions under which the scheme would likely operate.

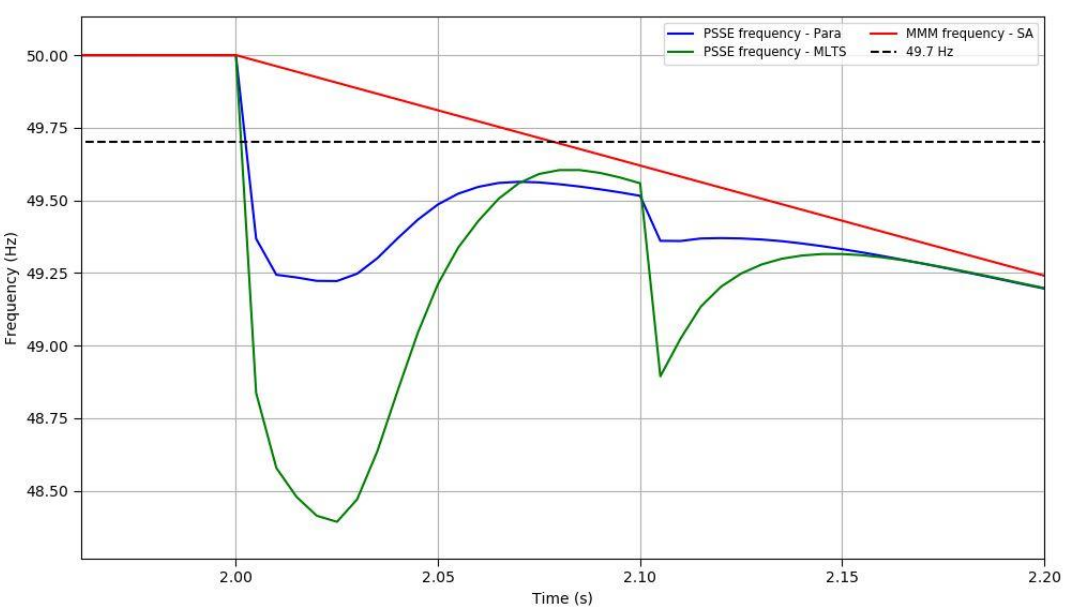
The PSS®E outcomes for the first two (more severe) events show frequency transients occurring within the first 50 ms of a non-credible separation event, which do not appear in the MMM outcomes. In both these cases, EAPT Mode 1 would have activated within 190-210 ms in response to frequency transients, a very similar timeframe to EAPT Mode 2. This is termed ‘rapid’ EAPT Mode 1 operation.

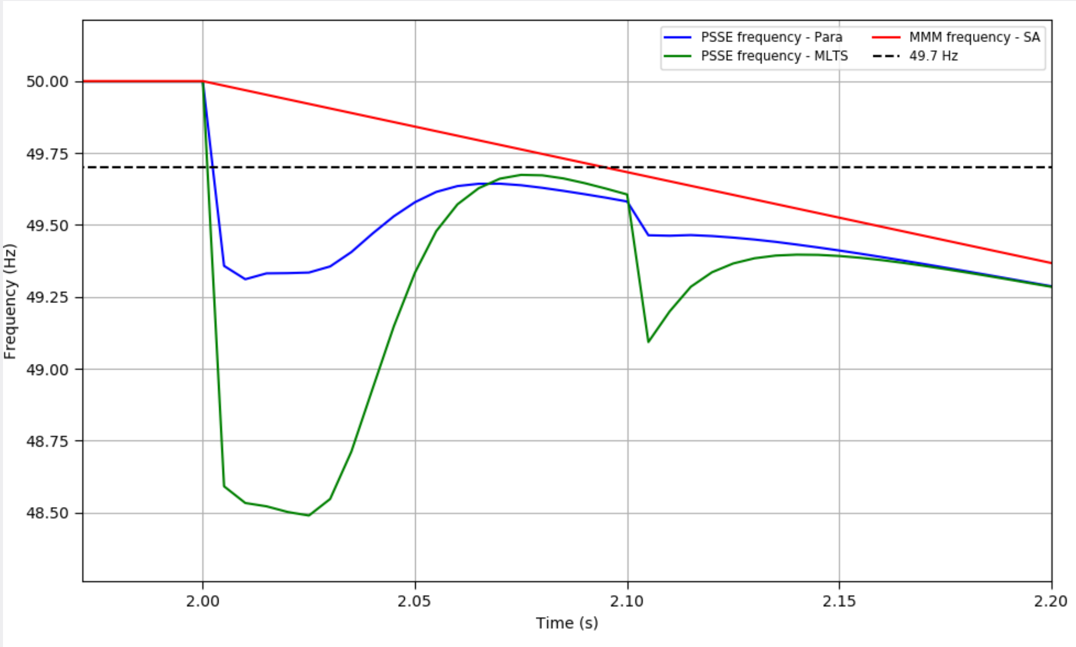
The third case study is a less severe event with initial RoCoF <2 Hz/s (300 ms average). In this case, EAPT activated in 400 ms as the initial frequency transient was insufficient to activate rapid EAPT Mode 1 operation.

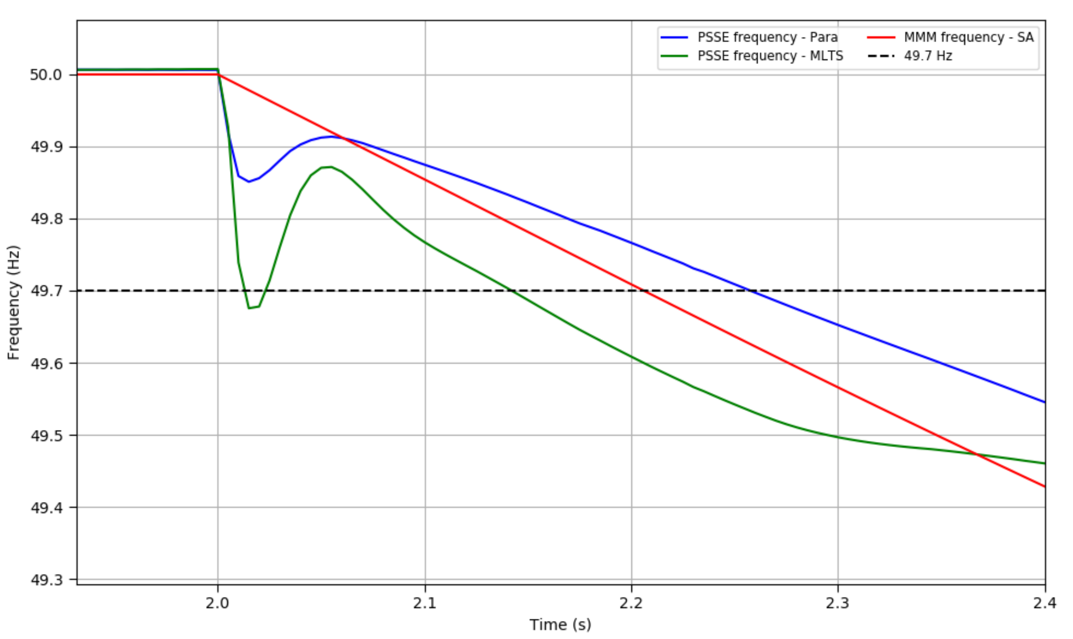
[87] AEMO (October 2021) *Victorian Annual Planning Report*, Section 4, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2021/2021-victorian-annual-planning-report.pdf?la=en.

[88] AEMO (January 2019) *Final Report – Queensland and South Australia system separation on 25 August 2018*, Section 3.4, 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.

Figure 70 Benchmarking – PSS®E vs MMM – separation at [5] leading to under-frequency in South Australia

<table>
<tr><th>OPDMS snapshot timestamp (AEST)</th><th>Frequency profiles:
Red – MMM frequency - SA
Dark blue – PSS®E frequency at Para
Green – PSSE®E frequency at Moorabool</th></tr>
<tr><td>11/11/2018 15:00</td><td>RoCoF post separation (300ms):
• MMM: -3.7 Hz/s
• PSS®E Para: -3.8 Hz/s
• PSS®E MLTS: -3.8 Hz/s
‘Rapid’ EAPT Mode 1 operation was observed: EAPT Mode 1 activated within 200 ms of separation.
</td></tr>
</table>

OPDMS snapshot timestamp (AEST)	Frequency profiles: Red – MMM frequency - SA Dark blue – PSS®E frequency at Para Green – PSSE®E frequency at Moorabool
10/02/2019 02:30	RoCoF post separation (300ms): • MMM: -3.1 Hz/s • PSS®E Para: -3.3 Hz/s • PSS®E MLTS: -3.3 Hz/s **'Rapid' EAPT Mode 1 operation was observed:** EAPT Mode 1 activated within 200 ms of separation. 

OPDMS snapshot timestamp (AEST)	**Frequency profiles:** Red – MMM frequency - SA Dark blue – PSS®E frequency at Para Green – PSSE®E frequency at Moorabool
27/02/2019 11:00	RoCoF post separation (300ms): • MMM: -1.4 Hz/s • PSS®E Para: -1.2 Hz/s • PSS®E MLTS: -1.7 Hz/s **'Rapid' EAPT Mode 1 operation was not observed:** EAPT Mode 1 activated within 400ms of separation. 

The frequency transients observed in the first two examples in Figure 70 are important because they meet the frequency performance criteria of the EAPT scheme in Mode 1, and are therefore sufficient to trigger rapid operation of the EAPT scheme.

These PSS®E/MMM benchmarking studies suggest:

- If initial RoCoF exceeds -2 Hz/s (300 ms average) in the MMM, the corresponding case study in PSS®E shows short duration frequency transients in the first 50 ms following a separation. These frequency transients likely mean the EAPT Mode 1 frequency performance criteria will be met rapidly, with 'rapid' EAPT Mode 1 operation times of 190-210 ms following separation.
- If initial RoCoF is slower than -2 Hz/s (300 ms average) in the MMM, these frequency transients are not observed and 'rapid' EAPT Mode 1 triggering would not be observed. Hence, under this low RoCoF condition, EAPT Mode 1 operation time is more likely in the order of 300-500 ms, and will occur in response to the general frequency dynamics which are well represented by the MMM.

Because the MMM does not accurately represent frequency transients, a RoCoF proxy was developed to determine conditions where 'rapid' EAPT Mode 1 operation is likely. This reproduced the observed PSS®E results in the MMM for frequency transient effects.

EAPT RoCoF proxy (EAPT trigger on frequency transients)

If average RoCoF in the MMM exceeds -2 Hz/s (100 ms average), EAPT Model 1 is assumed to operate within 190-210 ms of separation (‘rapid’ EAPT Mode 1 operation).

A 300 ms averaging window is typically used for RoCoF measurements in this report, as well as the 2022 PSFRR. However, the EAPT RoCoF proxy uses a 100 ms averaging window, as rapid EAPT Mode 1 operation can occur within 190 ms and a shorter window is therefore required. Table 58 shows that RoCoF over 100 ms is similar to RoCoF over 300 ms in the MMM.

Table 58 Average RoCoF in the MMM: 100 ms averaging window versus 300 ms averaging window

OPDMS snapshot (AEST)	MMM RoCoF (100 ms average)	MMM RoCoF (300 ms average)
11/11/2018 15:00	-3.8 Hz/s	-3.7 Hz/s
10/02/2019 02:30	-3.2 Hz/s	-3.1 Hz/s
27/02/2019 11:00	-1.5 Hz/s	-1.4 Hz/s

EAPT activation on voltage

Under-frequency

Operation on voltage criteria was not observed for any benchmark cases with under-frequency in South Australia.

Following a separation at [5] leading to under-frequency in South Australia, if EAPT operates it is most likely to activate on frequency performance criteria. Total scheme operation time on voltage criteria is at least 500 ms based on the scheme delay settings. On the other hand, EAPT Mode 1 operation time on frequency criteria is typically 300-500 ms in the MMM, and the scheme may activate more rapidly if frequency transients occur (discussed above).

Over-frequency

Following a separation at [5] leading to over-frequency in South Australia, the MMM EAPT model assumes that EAPT Mode 1 activation on voltage criteria is unlikely.

A3.4.4 Network topology benchmarking: Local variation in RoCoF

Immediately post-contingency, RoCoF can vary at different buses across the NEM, and generator RoCoF ride-through depends on RoCoFs experienced at generator terminals. As such, the PSS®E studies shown in Figure 70, which use full NEM transmission network representation, were used to examine if the MMM provides a suitable representation of RoCoF experienced at the generator terminals in South Australia.

Figure 70 confirms that average RoCoF measurements at Para in the PSS®E model are well represented by the MMM. High RoCoF identified in the MMM is therefore considered a reasonable indication of high RoCoF at generator terminals in the Adelaide metropolitan area. Generators in this area include Torrens B and PPCCGT.

A3.4.5 Separation at [3], [4] or [5] – summary

The analysis conducted to date suggests that the MMM provides a suitable representation of power system dynamics for separations at [3], [4] or [5] leading to under-frequency in South Australia, if the proposed RoCoF proxy for rapid EAPT Mode 1 operation is implemented in the MMM (as has been done for all studies in this report).

For separations at [3], [4] or [5] that lead to over-frequency in South Australia, there may be complicating factors (such as instability on QNI) which have not been accounted for in this analysis, so these conditions are considered out of scope.

A4. Estimating USE, costs, and benefits

A4.1 Unserved energy estimates

The amount of USE associated with the various risks identified was estimated with the assumptions in Table 59.

Table 59 Assumptions for estimating USE

	Lowest cost black system	Central	Highest cost black system	Details
Underlying load in South Australia at the time of the system black event	1,247 MW (average spring weekend)	1,727 MW (average winter weekday)	1,845 MW (average summer weekday)	Average South Australian underlying demand (operational demand + demand served by DPV) in calendar year 2021, for representative types of periods. Underlying demand is the best estimate of actual customer disconnection, as load supplied by DPV will also be disconnected during a black system event.
Load restoration profile	0.25	0.25	0.25	Load restoration profile (% of energy restored) is based on the profile of load restored in the first eight hours following the 2016 Black System event[A]. In this event, load restoration commenced approximately 2-3 hours after the separation, and reached approximately 70% restored within eight hours.
Duration of system black event in South Australia	8 hrs	10 hrs	12 hrs	Duration to achieve majority of load restoration (assuming linear profile of restoration).
USE associated with each system black event (based on assumptions above)	7,481 MWh	12,955 MWh	16,608 MWh	Based on assumptions above.
Likelihood of a non-credible separation event at [1] to [5]	0.4 per year	0.6 per year	0.8 per year	Likelihood of a separation at any point between Heywood and Moorabool (refer to Section 3 for further details)
Location of separation event	A separation is equally likely to occur at Heywood ([1],[2]) or South-West Victoria ([3],[4],[5])			For simplicity, it is assumed that a separation is equally likely to occur in either network section. Due to network configuration, risks from a separation at [1] are identical to a separation at [2] for South Australia. Modelling indicates that risk profiles for a separation at [3],[4] or [5] are very similar (Figure 17, Section 6.2.2).
Likelihood of cascading failure – Containment studies	• "Fail" periods are assumed to have a 100% likelihood of leading to cascading failure • "Risk" periods are assumed to have a 50% likelihood of leading to cascading failure			Definitions of acceptance criteria are summarised in Section 4.9.1.
Likelihood of cascading failure – Recovery studies	**For under-frequency:** • "Fail" periods are assumed to have a 30% likelihood of leading to cascading failure • "Risk" periods are assumed to have a 1% likelihood of leading to cascading failure **For over-frequency:** • "Fail" periods are assumed to have a 10% likelihood of leading to cascading failure • "Risk" periods are assumed to have a 0.5% likelihood of leading to cascading failure			Definitions of acceptance criteria are summarised in Section 4.9.2.

A. AEMO (March 2017) *Black System South Australia 28 September 2016*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2017/integrated-final-report-sa-black-system-28-september-2016.pdf?la=en&hash=7C24C97478319A0F21F7B17F470DCA65.

A4.2 Estimating costs of risks identified

The USE estimates calculated using the above method were then used to give an order of magnitude estimate of the approximate annual costs of the risks identified.

Several different estimates for the costs of USE were applied:

- The VCR[89], estimated by the AER at $43.23/kWh in 2019, equivalent to $49.14/kWh adjusted for CPI to 2022 dollars (used throughout this report).
- 2 x VCR, a sensitivity to account for the escalated inconvenience and costs to customers from long duration outages. This is used as an additional sensitivity throughout the report, since[90]:
  - Standard VCR may not accurately estimate the impacts of widespread and/or prolonged outages. Additional offsets to the VCR might be appropriate to estimate effects not captured through customer survey.
  - VCR survey respondents are not expected to have a good understanding of the social and safety impacts related to widespread and/or prolonged outages. Extrapolating survey results to cater for this kind of event might necessitate additional offsets due to the non-linear nature of a VCR over time and space.
  - VCRs should not solely be relied on to assess high impact or prolonged widespread outages.
  - In previous assessments 2 x VCR has been applied as a proxy to capture additional direct and indirect economic impacts. This approach broadly aligns with the South Australian Council of Social Service (SACOSS), which used standard VCR and a sensitivity based on the economic impacts of a similar event, resulting in a multiple approximately 2.42 times VCR[91].

Table 60 applies these values to provide estimates for the range of cost of each system black event, based on the USE assumptions above. These values are consistent with previous estimates[92].

Table 60 Assumptions for estimating costs of a system black event

	Lowest-cost black system	Central	Highest-cost black system
USE associated with each system black event	7,481 MWh	12,955 MWh	16,608 MWh
Cost of a system black ($ million): Based on standard VCR	$368 m	$637 m	$816 m
Cost of a system black ($ million): Based on 2 x VCR	$735 m	$1,273 m	$1,632 m

[89] AER 2019, *Values of Consumer Reliability – Final Decision*, Table 5.22, https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf.

[90] AEMO (December 2014) Value of customer reliability – Application guide.

[91] AEMO (December 2016) *National Transmission Network Development Plan*, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Report/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.pdf.

[92] AEMO (November 2018) *AEMO request for Protected Event declaration,* https://www.aemc.gov.au/sites/default/files/2019-04/AEMO%20Request%20for%20protected%20event%20declaration.pdf.

These cost estimates can also be compared to estimates of the total cost of the black system event that occurred in South Australia on 28 September 2016[93]. This black system event was estimated to cost commercial customers alone $450 million (equivalent to approximately $523 million in 2022), based on customer surveys[94].

A4.3 Estimating costs of management measures

Where the proposed management measures involve constraints that change market dispatch when they bind, the impacts and costs of these constraints were estimated as follows:

- A merit order calculator was developed to estimate the most likely changes in system dispatch when the constraints bind. For constraints that limit imports into South Australia, this typically involves dispatching up units in South Australia, and dispatching down units in Victoria. Units were dispatched within their minimum and maximum generation limits, in order of SRMC[95], based on a gas price of $11-12/gigajoule (GJ)[96] and individual unit efficiency estimates. This is in alignment with the Plexos dispatch approach in the ISP models.
- For each half-hour where the constraint binds in the forecast horizon (2022-23 and 2023-24), the difference in total system costs associated with the changes in unit dispatch were calculated, based on estimated fuel costs and individual unit efficiencies.
- Total system costs were summed over the year for each forecast scenario.

A4.4 Estimating benefits of management measures

The benefits of the proposed management measures were estimated as follows:

- The power system outcomes for the updated dispatch patterns were modelled in the MMM. For each half-hour of the forecast dispatch period (2022-23 and 2023-24), the relevant non-credible contingency event was modelled (a separation at the Heywood Interconnector at points [1] or [2], or a separation in the South-West Victoria network at one of the points [3], [4] or [5]). The outcomes in each dispatch interval were assessed against the acceptance criteria summarised in Section 4.9.1, classifying them as a "pass", "risk" or "fail".
- The total USE in the year for each scenario (with or without the proposed management measures) was then estimated applying the assumptions in Table 59.
- The benefits of the management measure were estimated based on the estimated reduction in USE (comparing the two dispatch scenarios). The dollar estimates of benefits in avoided USE were estimated using the USE cost estimates outlined in Section A4.3.

[93] AEMO (March 2018) Black System South Australia 28 September 2016, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

[94] AEMC (December 2019) *Final Report: Mechanisms to Enhance Resilience in the Power System – Review of the South Australian Black System Event,* https://www.aemc.gov.au/sites/default/files/documents/aemc_-_sa_black_system_review_-_final_report.pdf; AEMC (July 2017) Information sheet: *Review of the System Black Event in South Australia on 28 September 2016*, https://www.aemc.gov.au/sites/default/files/2019-04/Information%20sheet%20-%20%20project%20update.PDF.

[95] In alignment with dispatch engine assumptions used for the market models studied in this report, unit start up and shut down costs were not used.

[96] AEMO (August 2022) *2022 Forecasting Assumptions Workbook*, 'Gas, Liquid fuel, H2 price', https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generator Control
APD	Alcoa Portland Aluminium Smelter
BIPS	Barker Inlet Power Station
BESS	Battery Energy Storage System
CCGT	Combined Cycle Gas Turbine
CNUN	Canunda wind farm
DPV	Distributed photovoltaics
EAPT	Emergency Alcoa-Portland Potline Tripping scheme
EFCS	Emergency Frequency Control Scheme
EMTT	Emergency Moorabool Transformer Tripping control scheme
EUFR	Emergency Under Frequency Response
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
FRM	Frequency Recovery Mode
FOS	Frequency Operating Standards
SWV GFT	South-West Victoria Generator Fast Trip scheme
GPS	Generator Performance Standard
GT	Gas Turbine
HGTS	Haunted Gully Terminal Station
HYTS	Heywood Terminal Station
IBR	Inverter Based Resources
ISP	Integrated System Plan
LKB	Lake Bonney Wind Farm 1-3
LOS	Loss of synchronism
MLTS	Moorabool Terminal Station
MMM	Multi-Mass Model
MOPS	Mortlake Power Station
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NSP	Network Service Provider
NER	National Electricity Rules
NSW	New South Wales
OEM	Original Equipment Manufacturer

Term	Definition
OFGS	Over Frequency Generator Shedding
PEC	Project EnergyConnect
PEC1	Project Energy Connect Stage 1
PFR	Primary Frequency Response
PPCCGT	Pelican Point Combined Cycle Gas Turbine
QLD	Queensland
RoCoF	Rate of Change of Frequency
SA	South Australia
SESS	South East Substation
SIPS	System Integrity Protection Scheme
ST	Steam Turbine
SW-VIC	South-West Victoria
SYTS	Sydenham
TAS	Tasmania
TRTS	Tarrone Terminal Station
UFLS	Under Frequency Load Shedding
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria