General Power System Risk Review – Appendices

July 2023

Final Report

A report for the National Electricity Market

Important notice

Please refer to the notice at the front of the 2023 General Power System Risk Review Final Report, which is published under clause 5.20A.3 of the National Electricity Rules. The Appendices in this document form part of that final report and are subject to the same disclaimer.

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Version control

Version	Release date	Changes
2.0	10/7/2023	Publication of final report

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

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A1. Status of actions arising from recent major incidents

Table 1 presents a summary and update of the status of recommendations arising from major reviewable power system incidents that occurred since 2018-19. Actions reported as Closed in the 2022 PSFRR are not included in the below table.

Table 1 Status of actions arising from major reviewable incidents

Incident	Recommendation	Status	Details
25 August 2018 – Queensland and South Australia system separation	**Primary frequency control in the NEM** • AEMO to work with the AEMC, AER and NEM participants to establish appropriate interim arrangements, through rule changes as required, to increase primary frequency control (PFC[1]) responses at both existing and new (synchronous and non-synchronous) generator connection points where feasible, by Q3 2019. • AEMO to support work on a permanent mechanism to secure adequate PFC as contemplated in the AEMC's Frequency Control Framework Review, with the aim of identifying any required rule changes to be submitted to the AEMC by the end of Q3 2019 with a detailed solution and implementation process completed by mid-2020.	Closed	• AEMO submitted a rule change proposal for mandatory PFR in August 2019. • Following the rule change, AEMO issued an Interim Primary Frequency Response Requirements document (IPFRR)[2] in June 2020, including implementation processes[3]. • The final Primary Frequency Response Requirements were published by AEMO on 08 May 2023[4]
	Circumstances for regional FCAS or frequency control AEMO to investigate whether a minimum regional FCAS requirement is feasible, or whether there is scope to manage frequency requirements arising from non-credible regional separation under the protected events framework in the NER after interim PFC outcomes at the end of Q3 2019.	Open	FCAS is only procured to cover credible events. Since the commencement of PFR implementation in 2020, a material improvement in frequency performance on the power system has been observed, lessening the frequency impact of non-credible events. Following implementation of very fast FCAS[5], AEMO will consider regional FCAS requirements.

[1] Now referred to as PFR, or primary frequency response.

[2] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/primary-freq-resp-req-doc-consultation/interim-pfrr-consultation-determination.pdf?la=en.

[3] The latest update on PFR implementation can be found at https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response.

[4] See https://aemo.com.au/consultations/current-and-closed-consultations/primary-frequency-response-requirements.

[5] As required by the National Electricity Amendment (Fast frequency response market ancillary service) Rule 2021 No. 8, https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service.

Incident	Recommendation	Status	Details
	Frequency response capability models Commencing in Q1 2019, AEMO to work with participants to obtain information required to fully and accurately model generator frequency response and all other active power controls.	Ongoing	AEMO continues to work with generators in monitoring their compliance obligations. AEMO plans greater collaboration with NSPs to improve the accuracy of generator models. AEMO wrote to all Generators with PFR-enabled synchronous generating units in September 2021, asking them to confirm that their OPDMS PSS®E models are up to date and reflects each generating unit's response to frequency events, or otherwise provide updates to the relevant NSP and AEMO.
	Emergency frequency control schemes AEMO to continue implementation and investigate any further functional requirements of EFCS for each region, commencing with SA and QLD prior Q1 2020	Ongoing	South Australia OFGS: Implementation of updated settings is being progressed with ElectraNet and subject to successful testing and commissioning this is expected to complete in Q3 2023. Queensland OFGS: AEMO has identified a need for an OFGS in Queensland. AEMO is working on the design and relevant consultation with Powerlink.
16 November 2019 – South Australia and Victoria separation	**Compliance of DPV systems** AEMO to work on auditing and establishment of methods for monitoring and improving compliance of DPV systems	Ongoing	AEMO has published a report on Compliance of Distributed Energy Resources with Technical Settings[6]. The report recommended, among other things, that industry efforts focus on improving compliance urgently, targeting at least 90% compliance of new installations with AS/NZS4777.2:2020 by the end of 2023. See Section 2.3.1 for more details.
4 January 2020 – New South Wales and Victoria Separation Event	**Review of projected assessment of system adequacy (PASA) tools** PASA did not correctly determine reserve levels in NSW after islanding due to the effective change in region boundaries.	Open	AEMO is currently undertaking the short term (ST) PASA Replacement project which will incorporate the recommendations from this incident. The planning phase of this project has been completed which included the development of a high level design of the new ST PASA. In order to allow AEMO to implement the new design, AEMO proposed a rule change to ST PASA in August 2021. The AEMC published the final rule change in May 2022 which becomes effective on 31st July 2025. The project is now in its final phase which includes development of the detailed design and formal procedure consultation followed by implementation of the new system to align with the rule change timelines.
	Identify sources on non-compliance in DPV systems 40-50% of DPV systems demonstrated behaviours that were not consistent with the relevant standards (AS/NZS4777.2:2015). This represents a growing power system security risk as more DPV continues to be installed. AEMO is working with stakeholders to identify and address sources of non-compliance	Closed	AEMO has published a report on Compliance of Distributed Energy Resources with Technical Settings[7]. The report recommended, among other things, that industry efforts focus on improving compliance urgently, targeting at least 90% compliance of new installations with AS/NZS4777.2:2020 by the end of 2023. See Section 3.3.1 for more details.
	Visibility of DPV systems	Open	AEMO has established Project MATCH with UNSW and ARENA funding to improve visibility of DPV system behaviour during disturbances. Work is in progress, with a present focus on

[6] AEMO *Compliance of Distributed Energy Resources with Technical Settings*, https://aemo.com.au/-/media/files/initiatives/der/2023/2023-04-27-compliance-of-der-with-technical-settings.pdf?la=en&hash=19A1CACD35565DAC69610542B2292DB3.

[7] AEMO *Compliance of Distributed Energy Resources with Technical Settings.*

Incident	Recommendation	Status	Details
	Visibility of DER is becoming increasingly important for assessment and management of power system security. AEMO (in collaboration with the Australian Renewable Energy Agency [ARENA], University of New South Wales [UNSW], Solar Analytics, WattWatchers, ElectraNet, TasNetworks and other stakeholders) is continuing work to improve data sources, analysis tools, and power system models to investigate and represent distributed energy resources accurately.		data to assess compliance with standards. See http://www.ceem.unsw.edu.au/project-match for more information.
31 January 2020 – Victoria and South Australia Separation Event	**Alcoa Portland Pty Ltd review options to limit impacts of voltage disturbances** The trip of the APD potlines was in response to the voltage disturbance caused by line faults. This is a known issue. APD has advised AEMO that it is reviewing options to minimise the impact to the plant during similar events, but has not determined a timeframe for this work.	Open	APD is reviewing options to minimise the impact to the plant during similar events but has not determined a timeframe for this work.
12 March 2021 – Trip of Torrens Island A and B West 275 kV busbars	**Identify root cause of Torrens current transformer (CT) failure** ElectraNet is working with the CT manufacturer to identify the underlying cause of the failure. Once identified, ElectraNet should share this information with AEMO and undertake any additional remedial actions.	Open	ElectraNet's investigation into the root cause of the CT failure is ongoing.
25 May 2021 – Trip of multiple generators and lines in Central Queensland and associated under-frequency load shedding	**AEMO to discuss with Generators the need to:** • Provide advice to AEMO when protection schemes and associated direct current supplies are temporarily not fully duplicated due to maintenance outages or equipment failure, and • Establish agreed protocols for managing such risks similar to those already in place with TNSPs.	Closed	AEMO has shared the findings of the final incident report with generators in the NEM and WEM, asking them to review the recommendations and how this incident might impact their own operations. The Power System Security Working Group has initiated a review of generator reclassification requirements which was published in the Power System Security Guidelines[8] on 3 March 2023.
	AEMO, TNSPs and Generators to review the emergency communications protocols This review will include: • A clear procedure to support the identification of potential motoring of generators and appropriate responses. • Roles, responsibilities and communication channels to be used in emergency circumstances.	Closed	A review of the emergency operational communications found the protocols to be adequate. The review was completed as part of discussions at the Power System Security Working Group and Control Room Operators Working Group.

[8] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715%20Power-System-Security-Guidelines.pdf.

Incident	Recommendation	Status	Details
	• A process to assess apparent discrepancies between SCADA and site observations and to agree on action to be taken. This will include any necessary training programmes for operating staff.		
	AEMO to review Stanwell trip to house load (TTHL) settings During review of this event, AEMO identified TTHL settings implemented at Stanwell Power Station that impacted its ability to remain connected to the power system following voltage disturbances. The under-voltage trigger was removed in September 2021 to reduce the likelihood of Stanwell Power Station disconnecting following network disturbances. AEMO will review with Stanwell whether to re-establish this trigger with revised settings.	Closed	AEMO has completed an assessment of all SRAS provider settings to review whether they sit outside of each generators GPS requirements.
	AEMO to assess the impact on power system resilience of generator protection settings that led to loss of generation.	Closed	AEMO has completed an assessment of all SRAS provider settings to review consistency with each generator's GPS requirements.
	Confirm whether Yarwun performance was in line with expectations AEMO is investigating whether the tripping of the Yarwun CCGT cogeneration unit was consistent with expected performance in response to conditions at its connection point.	Closed	The investigation concluded that Yarwun CCGT cogeneration unit tripped on the reverse power to protect the turbine prime mover. The generator experienced large power swings coming from the grid. The generator pole slip alarm also triggered, but reverse power protection operated first.
	AEMO to raise review of voltage control settings with TNSPs Based on observations following this event associated with unusual operating conditions, AEMO recommends that TNSPs review appropriateness of current settings for voltage control schemes under low system strength conditions.	Closed	At the May 2022 Power System Security Working Group, AEMO requested that TNSPs review the appropriateness of wide area voltage control scheme settings. TNSPs have completed a review and advised AEMO that the voltage control settings are appropriate.
	AEMO will Identify any practical changes to improve the accuracy of reserve forecasts following this type of event, including improved visibility, and forecasting of the response of controlled loads.	Open	AEMO is exploring a number of initiatives which it hopes will improve: • Visibility of embedded generators and virtual power plants. • The flow of relevant data from DNSPs to AEMO and TNSPs. Visibility of controlled and price sensitive loads.
	CS Energy's independent investigation into the root cause of this incident is ongoing. Once CS Energy's independent investigation is concluded, the findings will be shared with AEMO. AEMO and CS Energy may identify additional	Open	CS Energy's investigation into the root cause of this incident is ongoing.

Incident	Recommendation	Status	Details
	recommendations based on the outcome of this independent investigation.		
10 June 2022 - 25 June 2022: NEM market suspension and operational challenges in June 2022	AEMO to prepare a plan for when regional cumulative prices reach the cumulative price threshold (CPT) to better enable the management of the transition to administered pricing.	Closed	AEMO has now prepared a qualitative plan for when regional cumulative prices reach the CPT to better enable the management of the transition to administered pricing. This plan is consistent with the processes employed towards the end of the June market suspension, where AEMO managed generation dispatch on a rolling 24-hour lookahead basis and had daily communications with energy constrained scheduled generators to understand physical fuel constraints and associated unit energy limits that could impact future capacity availability.
	AEMO to identify tools and processes needed to cater for energy limitations.	Open	AEMO is currently in the process of identifying tools and processes needed to cater for energy limitations as part of the ST PASA Replacement Project: • The ST PASA Replacement Project involves a comprehensive review of the pre-dispatch (PD) and ST PASA methodology, exploring the development of a system that will serve the NEM now and into the future, noting that the current PD and ST PASA systems were designed when most of the generation in the NEM was supplied from large thermal units connected to the transmission network[9]. • This project includes a review of how the PD and ST PASA systems can best capture the sharing of reserves across different regions and the allocation of energy-limited resources.
	AEMO to continue actively engaging with the AEMC and industry with regard to reviews or rule change proposals relating to the administered price cap (APC), CPT and other market settings that influence the operation of the NEM[10].	Closed	On 17 November 2022, the Australian Energy Market Commission published a final determination and final rule on amending the APC in response to a rule change request received from Alinta Energy on 1 July 2022[11]. This determination increased the APC from $300/MWh to $600/MWh in every NEM region, which is effective until 30 June 2025. This increase will help ensure that the market continues to function effectively if the CPT is exceeded, and an APC is triggered.
	On 24 June 2022, AEMO completed an action to resolve a software error relating to FCAS pricing under market suspension conditions when normal dispatch pricing is in effect.	Closed	This issue was resolved on 24 June 2022, and no follow-up actions were required.
	AEMO to review processes used for projecting supply adequacy over the medium-term in light of this series of events. The review should identify processes, modelling and reporting that may assist for these types of	Closed	AEMO reviewed processes used for projecting supply adequacy over the medium term in light of this series of events as part of the NEM Reliability Forecasting Guidelines and Methodology Consultation, for which the final determination and final reports were published by AEMO on 28 April 2023[12].

[9] See https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project.

[10] On 1 July 2022, the AEMC received a rule change request from Alinta Energy to amend the National Electricity Rules to increase the APC from $300/MWh to $600/MWh in every NEM region. See https://www.aemc.gov.au/rule-changes/amending-administered-pricecap#:~:text=Rule%20Change%3A%20Pending&text=On%201%20July%202022%20the,initiated%20this%20rule%20change%20request.

[11] See www.aemc.gov.au/rule-changes/amending-administered-price-cap.

[12] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology.

Incident	Recommendation	Status	Details
	circumstances, particularly when factors contributing to fuel constraints emerge.		As part of this consultation, AEMO reviewed a number of reliability forecasting guidelines and methodologies and satisfied AEMO's requirements under: • AEMO's commitment to review processes used for projecting supply adequacy over the medium term, as specified in the market event and reviewable operating incident report for the NEM market suspension and operational challenges in June 2022. • The 'Enhancing information on generator availability in medium-term (MT) PASA' rule change[13]. • The AER's Forecasting Best Practice Guidelines, and AEMO's Reliability Forecast Guidelines (to review AEMO's forecasting methodologies at least once every four years). • NER 3.9.3D(e) (to review the Reliability Standard Implementation Guidelines at least once every four years). Further, AEMO may implement minor and administrative changes related to the 'Integrating energy storage systems into the NEM' rule change (IESS Rule Change)[14].
	AEMO is conducting a review of gas market prices / parameters.	Closed	From September 2022, AEMO conducted the Gas Market Parameter Review 2022[15]. The review covered the Declared Wholesale Gas Market (DWGM) and the Short Term Trading Market (STTM). This review was conducted under rule 492 of the National Gas Rules (NGR) for the STTM market parameters, in accordance with the standard consultative procedure requirements detailed in rule 8 of the NGR. There is no rule requirement for the review of the DWGM market parameters, but AEMO decided to review them in conjunction with the STTM market parameter review. The final decision on the AEMO Gas Market Parameters 2022 and Market Reform Final Report were published on 16 February 2023[16]. AEMO's final determination was that the STTM and DWGM market parameters are appropriate and should remain unchanged.
Trip of South East – Tailem Bend 275 kV lines on 12 November 2022	AEMO recommends ElectraNet complete its investigation of the tower failure and advise of any additional risks or need for reclassification to manage system security. Once investigations have been completed later this year, AEMO will publish a supplementary or updated report including further details on the results of ElectraNet's investigations and any further actions ElectraNet is taking or considers it will need to take in response to the tower failure.	Ongoing	ElectraNet's preliminary investigation indicates the presence of specific ground conditions at the footings of the failed tower which materially contributed to a footing failure. ElectraNet's detailed investigation is ongoing.

[13] See https://www.aemc.gov.au/rule-changes/enhancing-information-generator-availability-mt-pasa#:~:text=Rule%20change%20request%20and%20background,availability%20in%20the%20MT%20PASA.

[14] See https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

[15] See https://aemo.com.au/consultations/current-and-closed-consultations/gas-market-parameter-review-2022.

[16] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/gas_consultations/2023/gas-market-parameter-review-2022/aemo---final-determination---gas-market-parameters-review-2022.pdf?la=en.

Incident	Recommendation	Status	Details
	AEMO recommends that compliance of DER with technical settings (AS/NZS4777.2:2020) in all regions is improved as an urgent priority, targeting at least 90% of new installations to be set correctly to AS/NZS4777.2:2020 by December 2023. This requires collaborative engagement from many stakeholders.	Closed	AEMO has released a comprehensive report outlining evidence on non-compliance and proposed next steps[17]. The report identifies a number of rapid improvements that can be implemented under existing frameworks (particularly by DNSPs and original equipment manufacturers [OEMs]) and provides insights to support development of improved enduring governance frameworks. These insights have been shared with the AEMC for consideration in its review on consumer energy resources technical standards[18].
	AEMO recommends SA Power Networks implement improved frameworks in South Australia to achieve consistently high compliance of DPV systems with curtailment requirements (ensuring systems are properly set up, and maintained over time, to deliver curtailment requirements, and can be curtailed in an accurate and timely manner when directed).	Open	All curtailment options contributed to managing system security were utilised. Post-incident investigation provided insights on the various methods for DPV curtailment applied: • SCADA-controlled DPV – larger DPV systems (approximately 200 kilowatts [kW] capacity and greater) were curtailed first and responded as expected. • Directions to Relevant Agents under the Smarter Homes regulations – of the 517 MW of DPV capacity installed under this scheme, 25-42% were observed to respond as required in this event. SA Power Networks estimates that only 51% of systems are set up properly at the point of commissioning. Response rates were lowest on 13 and 14 November 2022 due to impacts of telecommunications outages caused by severe weather. In addition, response rates varied significantly between different Relevant Agents, with some achieving total response rates of 80-90%, and others achieving a response rate of 10-20% or lower. • Enhanced Voltage Management (EVM) – SA Power Networks uses EVM to regulate voltage levels throughout the year and, under normal circumstances, maximise the amount of energy that DPV systems can generate. A side-benefit of EVM is that at certain higher voltage levels, a subset of DPV systems will disconnect. This method of disconnecting DPV can be used as a last resort when required to maintain system security. It is estimated that at least two-thirds of the DPV curtailment during this event was delivered by EVM. Without this EVM capability, AEMO would have likely been unable to maintain power system security during high DPV periods, especially on 13, 17 and 19 November 2022. However, EVM also led to some DPV systems demonstrating cycling behaviour (repeated switching on/off every 10-20 minutes), and impacted FCAS availability of distribution-connected resources.
	AEMO recommends emergency curtailment backstop capabilities are to be implemented in all regions (ability to curtail all new DPV installations to zero active power if required as a last resort to maintain power system security) as a priority.	Open	NSPs, governments, AEMO and the AEMC will all likely need to play a role in delivering these capabilities, preferably with national consistency. In implementing emergency backstop capabilities, consider: • Mechanisms and frameworks for managing compliance (during initial set-up and maintained over time). • The robustness of the technical approach applied, especially under conditions where communications networks may be compromised and there may be widespread power outages (due to flooding, bushfires, storm damage, or other reasons). These types of

[17] AEMO (April 2023) Compliance of Distributed Energy Resources with Technical Settings, https://aemo.com.au/-/media/files/initiatives/der/2023/compliance-of-der-with-technical-settings.pdf?la=en.

[18] AEMC, Review into consumer energy resources technical standards, https://www.aemc.gov.au/market-reviews-advice/review-consumerenergy-resources-technical-standards.

Incident	Recommendation	Status	Details
			conditions may coincide with challenging grid conditions where emergency backstop capabilities are required. • Suitable fallback settings (default behaviour that each DER inverter is programmed to autonomously perform if communications is lost for an extended period). • Standards-based schemes for DPV management (such as IEEE 2030.5 CSIP-AUS), targeting consistency of approach across jurisdictions, and ensuring inverters respond quickly and consistently, supporting predictable fallback behaviours, and simplifying implementation for DNSPs and equipment manufacturers. • Methods that allow selective curtailment capability on an individual system-by-system basis, for example, so FCAS delivery is not inhibited in periods where active DPV management is in use. Consideration should also be given to the possible use of these curtailment mechanisms to assist in managing DPV during a system restart. • Options for managing cyber security risk including cyber-informed engineering and the capability for achieving redundancy and robustness in data and control pathways for the purpose of being able to isolate and disconnect potentially compromised DER nationally.
	By end of 2023, AEMO, SA Power Networks, and the relevant market participants to investigate the availability of DER to deliver FCAS during periods of DPV curtailment.	Open	This work should seek to understand how these resources might be affected by the various mechanisms used to manage DPV, and ensure appropriate processes and tools are in place to deliver accurate FCAS availability estimates in real time.
	By Q1 2024, AEMO to develop a plan for implementing fit-for-purpose improvements to tools that monitor the DPV in operation in real time and the visibility of DPV curtailment when it is occurring.	Open	Throughout this incident AEMO lacked real-time visibility of DPV output in SA. This impacted AEMO's, ElectraNet's and SA Power Networks' ability to respond to the incident effectively.
Trip of Liapootah – Palmerston – Waddamana No 1 and No 2 220 kV lines on 14 October 2022	AEMO recommends TasNetworks considers the installation of line circuit breakers and any associated works to enable the Liapootah – Waddamana and the Waddamana – Palmerston circuits to be sectionalised at Waddamana as part of its plans for Waddamana substation to improve security for the loss of any of the line sections.	Open	The Liapootah – Waddamana - Palmerston 220 kV transmission lines provide a critical connection between northern and southern Tasmania. The two circuits also provide a connection for Cattle Hill Wind Farm. At Waddamana, each circuit is connected to one 220 kV busbar via isolators. As a result, a fault anywhere between Liapootah and Palmerston results in the loss of the complete circuit length, as well as a busbar at Waddamana.
	AEMO recommends TasNetworks and Musselroe Wind Farm review the inputs to the Anti-Islanding Scheme to minimise the risk the wind farm disconnects due to Slip Acceleration under similar network conditions.	Open	TasNetworks has confirmed that if significant voltage drops occur during network faults, the wind farm will enter its multiple fault ride-through mode, causing the active power to drop significantly to maintain connection without tripping. During this incident, the wind farm finally tripped due to the operation of its Anti-Islanding Scheme triggered by the Slip Acceleration RoCoF input.
	AEMO recommends Hydro Tasmania implements the UEL function during the AVR replacement planned by Hydro Tasmania at Lemonthyme Power Station during 2024. This function should minimise the risk of the power station tripping under similar fault conditions.	Open	During this incident, Lemonthyme tripped on under-excitation protection due to operating with high reactive import and low terminal voltage immediately prior to the high bus voltage at Sheffield. As a result of the trip of the 220 kV lines and the trip of Basslink and subsequent operation of the Frequency Control System Protection Scheme (FCSPS), the north part of Tasmania initially experienced low voltages and then high voltages during this incident. The

Incident	Recommendation	Status	Details
			existing Automatic Voltage Regulator (AVR) at Lemonthyme does not include the Under-Excitation Limiter (UEL) function.
	Whilst the Basslink protection operated as designed under this condition, AEMO recommended Basslink modify its operating procedure for returning Basslink to service to highlight the risk that high bus voltages, >231 kV in Tasmania or >544 kV in Victoria, the AC filters from being switched which, during the Basslink deblock sequence, will result in a trip of Basslink.	Closed	The trip of Basslink while transferring 0 MW at 0959 hrs on 14 October 2022 following restoration to service was due to high 220 kV bus voltages, more than 1.06 p.u. (above 232 kV), at George Town substation inhibiting the AC filters from being available to switch into service. Under this scenario, Basslink was unable to operate and tripped. AEMO was advised by Basslink on 9 June 2023 that it has updated its operating procedure.
	Following the approval of TasNetworks on 15 December 2022 and AEMO on 19 December 2022, it was recommended that Basslink add a 100 ms inhibit of thyristor monitoring after commutation failure.	Closed	This change was implemented by Basslink on 21 December 2022. This effectively removes the Basslink extended commutation failure trip mechanism and reduces the risk of a Basslink trip under similar conditions as resulted during this event. On 30 January 2023, AEMO issued MN 105392 removing the reclassification of the coincident trip of Basslink with any transmission line in Tasmania for Basslink flow in the direction of Victoria to Tasmania as a credible contingency event. The reclassification removal was made based on information from TasNetworks following the setting changes applied due to this recommendation.

A2. Status of previous PSFRR recommendations

Table 2 contains the status of previous PSFRR recommendations and a brief update on actions taken to progress each recommendation.

Table 2 Summary of previous PSFRR recommendation status

Report	Recommendation	Status	Update
2020 PSFRR (Exec. Summary, Page 7)	Emergency Alcoa Portland Tripping scheme review	Closed	AEMO recently completed several reviews of EAPT in response to an operation in 2018[19] and also as part of an impact assessment of recent network changes. As a result, setting changes have been implemented to minimise the risk of future mal-operation, and recommendations made to further modify the scheme to improve its reliability. Other findings include: • It is inappropriate to modify the EAPT to address a frequency performance issue introduced by high generation along the HYTS to MLTS lines. AEMO's preferred solution to address this generation-driven issue is to trip or runback generation, not to trip APD load. It should be noted that all existing generation connected along the line, with the exception of Macarthur WF, would be tripped if separation from MLTS occurs, which could be sufficient in addressing any issue driven by renewable generation connected to South-West VIC. • The reliability of the EAPT scheme could be greatly improved by changing its contingency detection from a performance-based approach to a topology-based approach. This is in line with the *Final Report – Queensland and South Australia System Separation on 25 August 2018* and the 2020 PSFRR recommendation to avoid mal-operation due to unexpected interaction with Interconnector Emergency Control Scheme (IECS). The EAPT upgrade project is currently scheduled to be completed by end of August 2023. • With the use of the topology-based contingency detection, the response time of the scheme will be minimised, which will address the high RoCoF issue identified in the PSFRR, and also improve coordination between EAPT and UFLS as recommended by the 2020 PSFRR. • If necessary, AEMO will investigate, jointly with ElectraNet, possible new control schemes to address any high generation-driven issues. AEMO will continue to monitor the latest changes in the area and will assess the need to further modify the EAPT accordingly.
2020 PSFRR (Section 2.5.1, page 25)	ElectraNet in collaboration with AEMO to enhance the reliability of the system integrity protection scheme (SIPS) by implementing a WAPS	Ongoing	Stage 1 and Stage 2 of SIPS (the battery response and load shedding stages) will be replaced by a WAPS, which will dynamically calibrate load shedding and battery response to increase the effectiveness of the scheme at preventing Heywood separation following a trip of SA generation, while minimising the amount of load shed. WAPS is currently being commissioned, with full operation expected by September 2023.

[19] See AEMO, *Final Report – Queensland and South Australia System Separation on 25 August 2018*, 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?la=en&hash=49B5296CF683E6748DD8D05E012E901C.

Report	Recommendation	Status	Update
			Stage 3 of SIPS (loss of synchronism protection of the Heywood interconnector) will remain in place.
2020 PSFRR (Exec. Summary, Page 4)	Protected event recommended for the non-credible synchronous separation of SA from the rest of the NEM be considered a protected event	Closed	AEMO is not recommending the declaration of a protected event for the separation of South Australia from the rest of the NEM at this time. Further details are available in Section 7.3 and in the report[20] on these studies.
2020 PSFRR (Section 4.1.5, page 39)	Powerlink and Energy Queensland to review UFLS and implement measures to mitigate the impacts of DPV.	Closed	This recommendation was superseded by recommendation 4b from the 2022 PSFRR.
2020 PSFRR (Section 6.2.1, Table 37, page 73)	Various recommendations to address the identified SA UFLS issues	In progress	As reported in Section 6.3, several initiatives are underway to address these issues: • SA Power Networks and ElectraNet have now added additional load to UFLS. • Dynamic arming of UFLS in South Australia commenced rollout in October 2022. The project will recover an estimated 385 MW[21] to the UFLS scheme in South Australia by the time of completion in 2024. • AEMO has provided recommendations to SA Power Networks about adaptive arming (updating relay frequency settings in real-time depending on power system conditions), indicating this provides some benefit to minimise binding of Heywood constraints, although implementation may only be justified if costs are low. • AEMO is providing recommendations to SA Power Networks about increasing the amount of load on delayed UFLS blocks to better assist frequency recovery[22]. SA Power Networks identification of circuits and implementation underway (target completion: 2024). • SA Power Networks is pursuing a tender process to procure Emergency Under Frequency response as a complement to traditional UFLS. Responses from EOI not economically viable, exploration of alternate pathways to procure additional EUFR ongoing.
2020 PSFRR (Exec. Summary, Page 6 and page 70)	AEMO, in consultation with ElectraNet, will review the effectiveness of the OFGS and modify it if required, to include additional generation in the scheme.	In progress	AEMO and ElectraNet are progressing the implementation of updated settings. Subject to successful testing and commissioning, this is expected to complete in Q3 2023.
2020 PSFRR (Exec. Summary, Page 5 and page 66)	AEMO's studies indicate that managing the CQ-SQ flow and the amount of generation tripped under the SPS are the key variables for successful management of the non-credible loss of the Calvale – Halys double-circuit transmission line. Revisions to the SPS are required and	Closed	Wide area monitoring protection and control (WAMPAC) stage 1 is now in service, and this increases power system security compared with the original SPS. Although, there might still be some cases where the scheme does not provide coverage compared to the current maximum N-1 secure power transfer limit of 2,100 MW, Powerlink has assessed that, due to prevailing market conditions and generation availability, the likelihood of CQ-SQ power transfers exceeding the

[20] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/non-credible-separation-of-south-australia.pdf?la=en&hash=1F1702974B14DC704FB964C7A25E8645

[21] Estimated forecast based on historical feeder level data from SA Power Networks.

[22] Further information on AEMO advice on delayed UFLS is provided in 2022 Power System Frequency Risk Review, Section 3.3.3 (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.

Report	Recommendation	Status	Update
	underway. This confirms the urgent need for work being progressed by Powerlink in consultation with AEMO, to develop an enhanced CQ-SQ SPS.		reliable level afforded by WAMPAC stage 1 is considered low. As such, Powerlink is prioritising other applications of WAMPAC that will provide positive benefits to customers as Powerlink rolls out a large program of reinvestment and maintenance activities in Central and North QLD.
2022 PSFRR Recommendation 1	New Over Frequency Generation Shedding scheme to manage Queensland over frequency during Queensland separation: AEMO and Powerlink to implement OFGS in Queensland.	Ongoing	AEMO is currently working on the design of a Queensland OFGS in consultation with Powerlink.
2022 PSFRR Recommendation 2	To manage the loss of both Dederang Terminal Station – South Morang Terminal Station 330 kV lines: AVP to review existing Interconnector Emergency Control Scheme when Victoria is importing and develop a new Special Protection Scheme for when Victoria is exporting, jointly with Transgrid.	Ongoing	AVP's review of the existing IECS scheme for Victoria import conditions concluded that there is a low risk of losing the two adjacent single circuit transmission lines simultaneously. Hence, IECS is only armed at times of high bush fire risk for Victoria import conditions. AVP is currently working with Transgrid to investigate the instability issues for Victoria export conditions that were raised in the 2022 PSFRR. The evaluation of possible mitigation measures is ongoing.
2022 PSFRR Recommendation 3	To manage loss of both Columboola – Western Downs 275 kV lines: Powerlink to implement a new SPS under NER S5.1.8.	Ongoing	Powerlink has initiated a project to install WAMPAC panels in the Surat Zone to detect this double circuit non-credible contingency. The commissioning of these panels, analysis to determine the scheme's settings and commissioning of the scheme is planned to be completed by the end of 2024. Depending on the load and generation within Surat Zone, if there is a need to trip the generation outside of the Surat Zone to arrest possible QNI instability, the scheme will leverage the generators that are available under the CQ-SQ N-2 SPS.
2022 PSFRR Recommendation 4a	Management of Queensland Under Frequency Load Shedding: Powerlink and Energy Queensland to identify and implement measures to restore UFLS load, and to collaborate with AEMO on the design and implementation of remediation measures.	Ongoing	As reported in Section 6.3, several initiatives are underway to address these issues: • AEMO report provided to NSPs identifying declining load in UFLS due to DPV. AEMO recommended NSPs explore rectification options. • NSPs auditing UFLS scheme, identifying areas of improvement. • NSPs identify metering uplifts required, especially to identify UFLS circuits in reverse power flow • Energy Queensland are developing dashboard for real time visibility of UFLS load
2022 PSFRR Recommendation 4b	Queensland – New South Wales Interconnector instability: To manage QNI instability and separation after Heywood interconnector contingencies, AEMO plans to conduct further investigation to consider appropriate mitigation measures such as a protected event or work with Powerlink for a SPS under NER S5.1.8.	Ongoing	AEMO completed a protected event assessment as part of the 2023 GPSRR, and studied events which could lead to QNI stability as a risk. As a result, the GPSRR recommends that Powerlink, in collaboration with Transgrid, designs and implements a SPS to manage QNI instability. See Sections 5.2 and 7.2 for more details.
2022 PSFRR Recommendation 5	Review of Wide Area Monitoring Protection and Control scheme to mitigate risks associated with non-credible loss of Calvale – Halys 275 kV lines: Powerlink to review the adequacy of WAMPAC to manage increased risks due to QNI transfers increases following QNI upgrade.	Ongoing	Powerlink has focussed on updating transient stability limit advice for credible contingencies (N-1) for the CQ-SQ grid section and southerly power transfer across QNI based on AEMO's composite and DER load model. This work is being finalised with AEMO's respective due diligence. Following the completion of this work, Powerlink will prioritise reassessment of the CQ-SQ N-2 SPS settings, taking account of the revised composite and DER load model.

Report	Recommendation	Status	Update
			As connections of new renewable generators in CQ and NQ progress, Powerlink has been installing the necessary WAMPAC panels for these projects such that these plants can be integrated into the CQ-SQ N-2 SPS or, as appropriate, other WAMPAC based schemes. In addition to expanding the footprint for candidate CQ or NQ VRE generator tripping, Powerlink has also been leveraging planned secondary system replacement projects in SQ to (where appropriate) also install WAMPAC panels such that additional load blocks can be added into the CQ-SQ N-2 SPS and/or other schemes as required.
2022 PSFRR Recommendation 6	Further work is required to mitigate risks associated with reduced effectiveness of UFLS schemes as reported in the 2020 PSFRR: a) To address the impact of distributed photovoltaics growth on UFLS, NSPs should regularly audit the availability of effective UFLS considering the impact of DPV in their respective networks. b) NSPs to immediately seek to identify and implement measures to restore emergency under frequency response to as close as possible to the level of 60% of underlying load at all times. c) NSPs to investigate measures to remediate the impacts of 'reverse' UFLS operation due to negative power flow on UFLS circuits.	Ongoing	AEMO, in collaboration with NSPs has extensive current and planned work fronts to improve the efficacy of UFLS. These are discussed extensively in Sections 2.3, 6.3 and 6.4 of the 2023 GPSRR.
2022 PSFRR Recommendation 7	Further work is required to assess the impacts of higher RoCoF as system inertia reduces: AEMO will continue to monitor this in future GPSRRs and review OFGS/UFLS settings, if required.	Closed	AEMO has and will continue to monitor RoCoF risks on the NEM. As detailed in Section 6, AEMO is actively working with NSPs to improve the performance of EFCS.
2022 PSFRR Recommendation 8	Revise constraints on Heywood associated with the existing protected event for destructive wind conditions in South Australia: AEMO plans to retain the existing protected event until PEC stage 1 is commissioned. Post PEC stage 1 commissioning, during destructive wind conditions, AEMO plans to increase the Heywood Interconnector limit from 250 MW to 430 MW with PEC stage 1 flow to 70 MW.	Ongoing	AEMO considers the existing SA destructive winds protected event, as currently declared, is better aligned with the modified contingency reclassification framework, which considers power system security during temporary 'abnormal conditions' and now recognises 'indistinct events' where the specific assets at risk and impacts cannot be explicitly identified. AEMO submitted a request to the Reliability Panel to revoke the protected event prior to 1 October 2023. See Section 7.1 for more details.
2022 PSFRR Recommendation 9	Manage risks associated with large generation ramping events in South Australia: AEMO is analysing historical ramping events to understand ramping risks and how changes in synchronous generator dispatch requirements could impact AEMO's ability to manage future ramping events. After its review is complete,	Ongoing	AEMO's analysis and review is ongoing.

Report	Recommendation	Status	Update
	AEMO plans to explore options to forecast and manage future NEM ramping events.		
2022 PSFRR Recommendation 10	Manage risks associated with non-credible loss of future North Ballarat – Sydenham 500 kV lines: The non-credible loss of the proposed 500 kV lines between North Ballarat and Sydenham during periods when the new 500 kV lines flow exceeds the limits of the parallel 220 kV lines could result in multiple line losses. AVP will consider this risk in the planning process.	Closed	The preferred option for the Western Renewable Link project has been updated to include a new 500kV line between Bulgana and Sydenham, instead of North Ballarat and Sydenham. The preferred option is still under public consultation. This recommendation is superseded by a recommendation 6 in the 2023 GPSRR.

A3. Study approach

The study approach for the 2023 GPSRR was previously outlined in the final approach paper[23]. The approach paper gave an overview of the general methodology for historical and future scenario selection, PFR governor models, IBR models for large-scale wind and solar generation, SPS models and OFGS models.

This section covers the models and assumptions used for the study in more detail. AEMO used both PSS®E and PSCAD™ software to assess the priority risks. Where FRT behaviours of IBR might impact the assessment, results were studied in PSCAD™. Other events were studied using PSS®E.

The full NEM model (as described in OPDMS) and simplified NEM models were used to study the network and its dynamic behaviour.

A3.1 Historical cases methodology

OPDMS system snapshots between 1 July 2021 and 30 June 2022 were used to assess the level of existing risk in the power system. Historical cases were selected based on the network conditions detailed in Table 3, to represent the system operating boundaries relevant for each contingency. A standard set of 15 OPDMS system snapshots were selected based on a detailed trend analysis and studied for all historical contingencies detailed in Section 4 and Section 5. To conduct an accurate assessment of existing system risk, AEMO did not alter the generation and load dispatch in these historical snapshots. The snapshot details, selection process and associated trend analysis is further detailed in Appendix A3.1.8.

Table 3 Study scenarios – historical studies

Scenarios	Line flows	Generation	Demand	IBR	Interconnectors	DPV	UFLS
Risk 1 (Wagga contingency)	High flows in lines 62, 63, and Line 51 (Wagga - Lower Tumut)	High generation (wind and solar) around Wagga and Darlington Point regions	High and low NSW and VIC demand	High IBR generation in NSW/VIC regions	High QNI QLD export and high HIC SA export	High DPV in NSW and VIC regions	Low UFLS in the NEM regions
Risk 2 (Tamworth contingency)	High flows (northerly and southerly) in lines that will be tripped for bus fault	High net generation from the plants that are likely to be tripped due to the bus fault	High and low NSW and VIC demand	High IBR generation in NSW/VIC regions	High QNI export /import and high HIC export /import	High DPV in NSW and VIC regions	Low UFLS in the NEM regions
Risk 3 (Mount Piper contingency)	High flows in on the lines 5A3 and 5A5 along with high flows in the parallel corridors to lines 5A3 and 5A5	High generation in Bayswater and Liddell regions that will impact the contingency	High and low NSW and VIC demand	High IBR generation in NSW/VIC regions	High QNI export /import and high HIC export /import	High DPV in NSW and VIC regions	Low UFLS in the NEM regions

[23] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/general-power-system-risk-review-approach-consultation/2023-gpsrr-approach-paper---final.pdf?la=en.

Scenarios	Line flows	Generation	Demand	IBR	Interconnectors	DPV	UFLS
NEM boundary conditions	Additional cases for a range of NEM demand, interconnector flows, synchronous generation dispatch and VRE operation.						

A3.1.1 Primary frequency response (PFR) governor models

PFR applied settings

PFR settings data applied to the generators were required to model generator frequency performance accurately. These settings were available to AEMO and were included in the model.

Governor models for units with no governor model available in OPDMS

Where generating units have implemented new PFR settings, updated governor models were not available to AEMO (in the majority of cases). To address this, AEMO developed three generic governor models corresponding to steam, hydro and gas turbines which represent governor response in line with new PFR settings during frequency events. These generic governor models were used for 2023 GPSRR historical studies.

Governor models for units with governors in OPDMS

Generators have an ongoing obligation to provide NSPs and AEMO with up-to-date modelling information which encompasses all control systems that respond to voltage or frequency disturbances on the power system. AEMO sent correspondence to all large mainland NEM generators of their obligations to provide updated frequency control models, and the need for this information to support the GPSRR. Where updated site-specific information was not available, generic governor models with appropriate PFR settings were used.

A3.1.2 IBR models for large-scale wind and solar generation

The following approach was used for modelling of IBR in the GPSRR studies:

- For those IBR units that have completed PFR commissioning, where appropriate, the generator supplied model represented in OPDMS was used.
- Legacy IBR plants represented in OPDMS as negative loads were represented using generic PSS®E IBR models.

A3.1.3 Special protection scheme (SPS) models

The SPS models that were considered in the GPSRR historical studies are outlined in Table 4 below.

Apart from the above SPS models, protection schemes relevant to key study contingencies were also included. These schemes are detailed in Appendix A3.1.7.

Table 4 Special protection scheme models considered

Model	Region	Model owner	Status
EAPT Scheme	VIC	AVP	Model being updated following review of the scheme (update by AEMO in progress). Existing model was utilised for 2023 GPSRR. Historic studies assumed performance-based operation (Mode 3).
Interconnector Emergency Control Scheme (IECS)	VIC	AVP	Model being updated following review of the scheme (per 2020 PSFRR recommendation[24]) (update by AEMO in progress). Existing model was utilised for 2023 GPSRR.
System integrity protection scheme (SIPS)/WAPS	SA	ElectraNet	It is expected that ElectraNet will develop and provide PSS®E and PSCAD™ models of the WAPS scheme (not available). Existing SIPS model was utilised for 2023 GPSRR historical studies.
CQ-SQ wide area monitoring protection and control (WAMPAC) scheme	QLD	Powerlink	WAMPAC model has been developed. Any changes following studies associated with 2022 PSFRR recommendation 5 were excluded based on model availability timeframe[25].

A3.1.4 Over frequency generator shedding (OFGS)

The OFGS models for South Australian generators were used in the OPDMS NEM model. Tasmanian OFGS models were included for historic cases as per the data and models provided by TasNetworks.

A3.1.5 Load, distributed photovoltaic (DPV) and under frequency load shedding (UFLS)

Load model

The AEMO composite load model (CMLD) was used to model load response in all GPSRR historical studies. AEMO, NSPs and other stakeholders in the NEM conducting power system studies have used a traditional polynomial static load (ZIP) model to represent the majority of NEM load for over 20 years. Load composition has changed considerably over this time, and more sophisticated load models are now available. Adoption of the CMLD model is generally considered industry best practice[26,27].

The composite load model structure is shown in Figure 1.

It consists of six load components at the end of a feeder equivalent circuit, which is represented by a series impedance and shunt compensation. It is intended to emulate various load components' aggregate behaviour. It includes three three-phase (3P) induction motor models (motor A, B and C), a single-phase (1P) capacitor-start motor performance model (motor D), static load components (constant current and constant impedance), and a power electronic load model (constant active and reactive power)[28].

[24] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-2/2020-psfrr-stage-2-final-report.pdf?la=en.

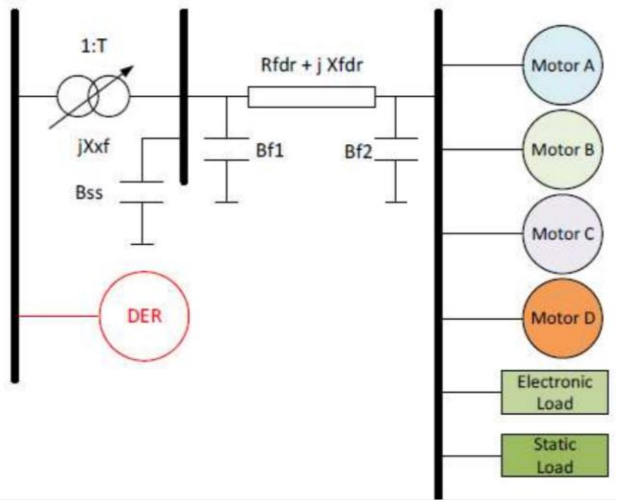
[25] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en.

[26] NERC Reliability Guideline – Developing Load Model Composition Data, March 2017, at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_-_Load_Model_Composition_-_2017-02-28.pdf.

[27] NERC Technical Reference Document – Dynamic Load Modelling, December 2016, at https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/Dynamic%20Load%20Modeling%20Tech%20Ref%202016-11-14%20-%20FINAL.PDF.

[28] See https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

Figure 1 The CMLD model structure and the implementation of the DERAEMO1 model



The CMLD model captures load shake off in response to large disturbances, which is a significant improvement compared with the previous ZIP model, which does not represent load shake-off. Since the CMLD model comprises explicit representations of different motor types, the load dynamics due to the response of motors are better captured.

UFLS and DPV mapping to buses

At this time, AEMO does not have a PSS®E model of UFLS that accurately maps the load and DPV behind UFLS relays to individual transmission buses for all NEM regions. This model is under development.

To deliver studies for this report, an interim approach was applied:

- For cases where regional NEM frequencies did not fall below 49 Hz (and UFLS therefore was not triggered), the standard DPV modelling approach was applied[39]. DPV generation was lumped at different bus locations in the OPDMS full NEM model based on data from DNSPs and the Clean Energy Regulator which was analysed and compiled by AEMO as part of the development of the DERAEMO1 model. This approach most accurately reflects the physical distribution of this type of generation in the system. Therefore, it better captures how rooftop PV generation will respond to power system disturbances, because the proximity of rooftop PV installations to the fault location is better represented.
- For cases where regional NEM frequencies did fall below 49 Hz, it is important to include a representation of UFLS. For these cases, a lumped representation of UFLS and DPV was applied, mapping load and DPV against UFLS relay settings randomly to achieve the overall total net UFLS in each frequency block[29]. The number of regional lumped blocks that were considered are detailed below. The individual blocks were dispersed across the relevant region and the PSS®E UFLS relay dynamic model was attached to each lumped UFLS load.
  - 121 New South Wales UFLS bands.

[29] System loads were randomly assigned to each UFLS band. DPV generation was then added to each UFLS load based on static percentage data representing the amount of DPV in each regional UFLS band. An additional load representing the load supported by the DPV was also added in conjunction with the DPV generation to ensure that the operational demand and power flows were maintained. Therefore, this approach could result in DPV being placed either electrically further away from or closer to the fault location than is the case in reality.

- 22 Victoria UFLS bands.
- 33 Queensland UFLS bands.
- 30 South Australia UFLS bands.
- Tasmanian UFLS models were included for historic cases as per the data and models provided to AEMO by TasNetworks.

This approach to modelling DPV and UFLS is anticipated to provide a reasonably accurate result for cases where frequency does not fall below 49 Hz (using the first approach), or where the disturbance is primarily frequency related, and there is minimal voltage disturbance (using the second approach). However, it will not be accurate for any case with a significant voltage disturbance involved that may lead to DPV shake-off[30]. For this reason, cases with a combined frequency disturbance below 49 Hz and significant voltage disturbance would present challenges regarding the modelling of both DPV tripping and UFLS behaviour. This issue will be further explored in future studies when suitable models are available.

A3.1.6 Wide-area EMT analysis

As part of the GPSRR 2023 historical studies, EMT analysis was conducted using the four state NEM PSCAD™ version 5 model that was released in July 2022. This model is made up of the four NEM mainland regions of New South Wales, Queensland, South Australia, and Victoria, and contains all the transmission networks elements, as well as key distribution network elements for each of these states. The use of this PSCAD™ network model allowed for a more detailed investigation of system voltages and IBR responses during and after the fault.

The Wagga contingency (Risk 1) was studied in PSCAD™ as well as PSS®E due to the possible impact that it could have on system voltages and IBR in the surrounding area. The loss of the double-circuit lines 62 and 63 was expected to impact the voltage fault ride through of nearby IBR generation due to the proximity of the fault, as well as the reduction in system strength from the loss of the lines. Any additional tripping of IBR would compound the impact of this contingency.

While a set of 15 system snapshots were studied in PSS®E as part of the analysis of the Wagga contingency, only a subset were studied in PSCAD™. These cases, and the reasons why there were selected, are listed below:

- Case 2: Minimum NEM demand.
- Case 4: Minimum synchronous generators.
- Case 5: Maximum IBR generation in NEM.
- Case 9: Minimum number of synchronous generators.
- Case 10: Maximum IBR in Wagga.
- Case 15: High generation near Bayswater and Liddell.

These PSS®E snapshots were used to initialise the PSCAD™ model and then dynamic studies were undertaken to analyse the system response to the contingency. Further details on the results of these PSCAD™ studies, such as plots and analysis, can be found in Section 5 and Appendix A5.1.3.

[30] The impact of a frequency disturbance is seen system-wide, whereas the impact of a voltage disturbance is localised. Therefore, when a fault leads to a voltage depression, this will only be seen by rooftop PV generators that are electrically close to the fault location.

A3.1.7 Control schemes considered in historical studies

The following sections detail the NEM control schemes that were modelled for the 2023 GPSRR historical studies.

Risk 1 – Wagga contingency

The following control schemes were modelled for the Wagga contingency.

X5 line tripping scheme

In the event of a contingent trip of line 63, a certain amount of through flow would be transferred to the parallel 132 kV interconnection between Darlington Point and Wagga, which could result in voltage collapse and 132 kV line overloads. To avoid this, the X5 Tripping Scheme trips line X5 for the contingent trip of line 63, offloading the Darlington Point transformers, and reducing the flow on the Darlington Point to Wagga 132 kV lines.

Silverton Wind Farm and Broken Hill Solar Farm transfer tripping scheme

This scheme, when armed, is to avoid overloading of Darlington Point 330/220 kV transformer or Victorian 220 kV network on tripping of line X3, X5, 63 or any of the two Darlington Point 220/330 kV transformers by tripping Broken Hill 22 kV feeder CBs (92 and 102) and Silverton WF 33 kV CBs (154, 159 and 160).

Limondale 1 and Sunraysia solar farms transfer tripping scheme

To protect the system from generator instability, voltage collapse, extreme voltage fluctuations or thermal overloading issues on trip of a number of transmission lines or transformers in south west New South Wales, by opening 33 kV CBs at Limondale 1 SF to disconnect the total solar farm generation from the grid without delay.

Wagga overload control scheme

At times of high power flow from Wagga 330 kV to Wagga 132 kV, a trip of either line 99X or 99W may result in an overload of the remaining in service line. An automatic SCADA-based control scheme monitors the flow on 99X and 99W. If an overload is detected the scheme will open line 990 at Yass and line 991 at Murrumburrah. There is a time delay of 20 s, to allow for a successful auto reclose of 99X or 99W.

Wagga North Solar Farm control scheme and Bomen Solar Farm control scheme

These schemes are installed to avoid island condition, voltage collapse, or extreme voltage fluctuations due to network reconfiguration or contingencies.

Darlington Point reactive control schemes

The fast voltage control scheme is designed to prevent voltage collapse in the event of a trip of Darlington Point – Wagga 63 330 kV line (and line X5 when the X5 trip scheme is auto). In the event of a trip of line 63, the scheme will switch in capacitors 3, 2, 1 in 0.2 s, 0.6 s and 1.0 s respectively if the 132 kV voltage is below 95%.

Balranald fast voltage control scheme for line 63 trip and Balranald fast voltage control scheme for line X5 trip

Tripping of Limondale 1 SF and Sunraysia SF may result in over voltage conditions at Balranald and Darlington Point. A fast Voltage switching scheme has been implemented to switch in shunt reactors at Darlington Point and

Buronga if these were switched out pre-contingency; and to switch out Darlington Point 132 kV shunt capacitor banks if these were switched in pre-contingency.

Risk 2 – Tamworth Contingency

The following control schemes were modelled for the Tamworth contingency.

Gunnedah Solar Farm control scheme

This scheme is designed to avoid overloading of the following elements in the event of changed system conditions or network contingency: 969 (Tamworth 330 – Gunnedah 132 kV transmission line) by running back or disconnecting the Gunnedah SF.

SCADA-based Armidale North Coastline overload load shedding scheme

The scheme monitors the lines 966 and 96C at Armidale end. If an overload in excess of the contingency rating of any of these lines is detected and the overload remains after a time delay of 25 s, the scheme will commence tripping the following feeders at Coffs Harbour, Koolkhan, and Kempsey in the order given below until the overload no longer exists.

White Rock generation runback scheme

The White Rock Generation runback scheme is designed to prevent overloads on lines 9U4 (Inverell – White Rock 132 kV) and 9UG (White Rock – Glen Innes 132 kV) by running back or disconnecting the White Rock WF.

Metz Solar Farm runback scheme

This scheme monitors overloading on line 966/1 or 966/3 and either reduces generation from or disconnects the Metz SF.

Risk 3 – Mount Piper contingency

The following control schemes were modelled for the Mount Piper contingency.

Gunnedah Solar Farm control scheme

This scheme is designed to avoid overloading of the following elements in the event of changed system conditions or network contingency: 969 (Tamworth 330 – Gunnedah 132 kV transmission line) by running back or disconnecting the Gunnedah SF.

Wellington under voltage load shedding schemes

At times of high load, loss of both Mount Piper – Wellington line 72 and Wollar – Wellington line 79 could lead to line overloads in the 132 kV network west of Mount Piper and Wallerawang. Whereas the firm capacity of this network is about 350 MW, the peak load has reached about 490 MW. To avoid this risk, an undervoltage load shedding scheme has been installed at Wellington which will shed Dubbo load. This represents about 160 MW peak load in summer and winter.

Wellington over voltage tripping scheme

This scheme will trip line 72 at the Wellington end in the event of an overvoltage (voltage > 363 kV for 2.5 s).

A3.1.8 Historical snapshot selection

To assess risks against historical operating conditions, AEMO used OPDMS snapshots representing operating boundaries relevant to each contingency event.

Identification of critical elements

As the first step, AEMO identified elements, such as lines, transformers, and nearby generators which could be critically impacted by each contingency event. The identified critical power system elements are given in Table 5. Note that IBR includes wind farms, solar farms and BESSs.

Table 5 Power system elements critically impacted by each risk

Risk	Worst case network conditions	Critically impacted elements
Wagga contingency	High flows in lines 62 and 63	• Wagga - Jindera (62) 330 kV line • Wagga - Darlington Point (63) 330 kV line
	High generation (wind and solar) in proximity to Wagga and Darlington Point substations	• Griffith SF • Darling Point SF • Wagga North SF • Bomen SF • Limondale 1 SF • Limondale 2 SF • Finley SF • Numurkah SF • Glenrowan West SF • Winton SF • Coleambally SF • Sunraysia SF • Junee SF • Sebastopol SF
Tamworth contingency	High generation output in proximity to Tamworth substation	• Gunnedah SF • Sapphire WF • White Rock SF • White Rock WF • Moree SF
Mount Piper contingency	High flows on lines 5A3 and 5A5 combined with high flows in parallel circuits	Northerly flow: • Mount Piper transformer 1 • Mount Piper transformer 2 • Bannaby - Sydney West (39) 330 kV line • Dapto - Sydney South (11) 330 kV line • Avon - Macarthur (17) 330 kV Southernly flow: • Wollar - Wellington (79) 330 kV • Bayswater - Regentville (31) 330 kV • Bayswater - Sydney West (32) 330 kV • Liddell - Newcastle (81) 330 kV • Liddell - Tomago (82) 330 kV
	High generation output in proximity to Bayswater and Liddell substations	• Liddell Power Station • Bayswater Power Station • Mt Piper Power Station • Crudine Ridge WF

Risk	Worst case network conditions	Critically impacted elements
		• Hunter Valley Power Station • Suntop SF • Wellington SF • Bodangora WF • Jemalong SF • Molong SF • Parkes SF • Goonumbla SF • Manildra SF • Beryl SF

Data collation

After AEMO identified the power system elements impacted by the risks, historical data for generation, demand, line and transformer flows in critical elements in the NEM from 1 July 2021 to 30 June 2022 was collated from the OPDMS. Table 6 provides a summary of the maximum and minimum values of the parameters that were considered by AEMO when selecting the relevant snapshots for use in these studies.

Table 6 Summary of the maximum and minimum values of the parameters (for FY 2021-22)

Parameter	Max (MW)	Min (MW)
Flow in line 51 (Wagga — Lower Tumut) (Wagga to Lower Tumut +ve)	766 (forward)	-434 (reverse)
Flow in line 62 (Wagga — Jindera) (Wagga to Jindera +ve)	426 (forward)	-297 (reverse)
Flow in line 63 (Wagga — Darlington Point) (Darlington Point to Wagga +ve)	510 (forward)	-211 (reverse)
IBR generation in proximity to Wagga and Darlington Point substations	15,25	0[A]
Net generation near Tamworth	563	0[B]
Net flow in lines 5A3 and 5A5 (southernly flow is +ve)	1,457 (forward)	-541 (reverse)
Net flow in parallel circuits to 5A3 and 5A5 lines (northerly flow)	-2,224	0
Net flow in parallel circuits to 5A3 and 5A5 lines (southernly flow)	2,890	0
Generation near Bayswater and Liddell substations	5,488	1,674
NSW demand	18,845	6,575
VIC demand	7,880	2,047
Total IBR generation in NSW	3,383	0[C]
Total IBR generation in VIC	3,220	0[D]
QNI flow (QLD export is +ve)	1,282 (forward)	-739 (reverse)
HIC flow (SA export is +ve)	678 (forward)	-693 (reverse)
DPV in NSW	3,485	0
DPV in VIC	2,630	0
NEM demand	30,128	11,893
Synchronous generation	30,680	8,491
IBR generation	8,664	415
DPV generation	10,604	0

A. -75 MW is observed in the trended data as the minimum.
B. -16 MW is observed in the trended data as the minimum.
C. -117 MW is observed in the trended data as the minimum.
D. -33.5 MW is observed in the trended data as the minimum.

Distributed photovoltaic assumptions

For the GPSRR historical studies, AEMO used half hourly DPV values calculated based on the Australian Solar Energy Forecasting System Phase 2 (ASEFS2) data[31]. To calculate the half-hourly generation data for photovoltaic non-scheduled generators (PVNSG), which is defined as PV systems larger than 100 kW but smaller than 30 MW non-scheduled generators, the half-hourly capacity factors of the small-scale DPV generators calculated from the ASEFS2 data is scaled by the PVNSG capacity for 2021-22. The small-scale PV and PVNSG capacities used for this scaling were taken from the 2021 Inputs, Assumptions and Scenarios Workbook[32]. To estimate DPV availability, AEMO then applied identical weather patterns to all small-scale PV and PVNSG in each region. The sum between the small-scale DPV and PVNSG was then used as the half hourly DPV generation values to select each historical snapshot.

Snapshot selection

Data collated from the OPDMS was used to co-optimise each network condition to obtain the most onerous system condition for each contingency. Historical cases were then selected based on the network conditions detailed in Table 7, to represent the system operating boundaries relevant for each contingency. Each historical contingency was assessed against all historical study scenarios.

Table 7 Study scenarios – historical studies

Scenarios	Line flows	Generation	Demand	IBR	Interconnectors	DPV	UFLS
Wagga contingency	High flows in lines 62, 63, and Line 51	High generation (wind and solar) around Wagga and Darlington Point regions	High and low NSW and VIC demand	High IBR generation in NSW/VIC regions	High QNI QLD export and high HIC SA export	High DPV in NSW and VIC regions	Low UFLS in the NEM regions
Tamworth contingency	High flows in lines (northerly and southerly) that will be tripped for bus fault	High net generation from the plants that are likely to be tripped due to the bus fault	High and low NSW and VIC demand	High IBR generation in NSW/VIC regions	High QNI export /import and high HIC export /import	High DPV in NSW and VIC regions	Low UFLS in the NEM regions
Mount Piper contingency	High flows in on the lines 5A3 and 5A5 along with high flows in the parallel corridors to lines 5A3 and 5A5	High generation in Bayswater and Liddell regions that will impact the contingency	High and low NSW and VIC demand	High IBR generation in NSW/VIC regions	High QNI export /import and high HIC export /import	High DPV in NSW and VIC regions	Low UFLS in the NEM regions
NEM boundary conditions	Additional cases for a range of NEM demand, interconnector flows, synchronous generation dispatch and VRE operation.						

The percentage quantities of the trended data were used to co-optimise each network condition to obtain the most onerous system condition for each contingency. When calculating the percentage trended values of the flows on transformers and transmission lines, the sign (direction of the flow) was taken into consideration. Therefore, the percentage was calculated based on the corresponding maximum value of the trended data for the particular flow direction. When calculating the percentage of other quantities, the percentage was linearly proportioned to the

[31] ASEFS2 involves the production of solar generation forecasts for small-scale DPV systems, defined as less than 100 kilowatt (kW) system capacity. The half-hourly generation data for small-scale PV is retrieved from ASEFS2 data (in NEO) from 1 July 2021 to 30 June 2022.

[32] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

minimum and maximum of the trended data. For example, the minimum and the maximum load level obtained from the trended data was 10 MW and 110 MW, respectively. The load level of a specific timestamp of 20 MW would have a percentage of 10% which is proportioned to these minimum and maximum values.

Wagga contingency

The Wagga contingency is related to the loss of Wagga – Jindera (62) and Wagga – Darlington Point (63) 330 kV lines contingency. As this contingency could affect the post-contingent ride-through performance of IBRs and voltage management, the following parameters were taken into consideration when selecting the snapshots:

- The IBR generation near Wagga and Darlington Point regions.
- The flow in Wagga – Darlington Point (63) 330 kV line.
- IBR generation in New South Wales.

It was not possible to find snapshots that achieve the historical maximum values simultaneously for all the parameters given above. Therefore, when selecting snapshots, the snapshot with the highest possible value for each parameter was selected while maximising the flow on the Wagga – Darlington Point (63) 330 kV line. As most of the IBR generators are in Darlington Point, the Darlington Point – Wagga (63) 330 kV line is prioritised over Wagga – Jindera (62) 330 kV line. The individual values of each system condition that relates to the Wagga contingency for each snapshot are given in Table 8.

Figure 2 Scatter plot of total IBR generation near Darlington Point and Wagga and power flow on Darlington Point – Wagga 330 kV line for FY 2021-22

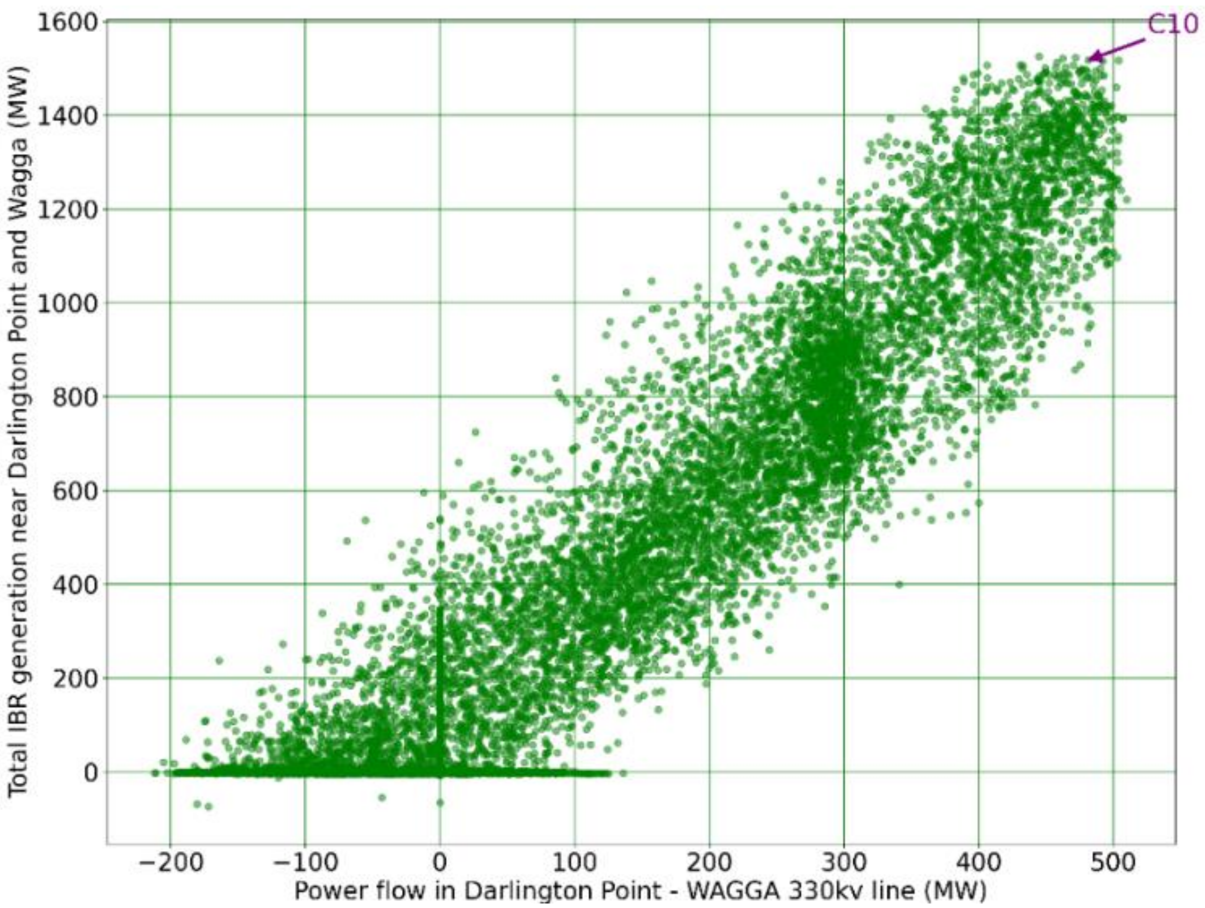


Figure 3 Scatter plot of total IBR generation in New South Wales and power flow on Darlington Point – Wagga 330 kV line for FY 2021-22

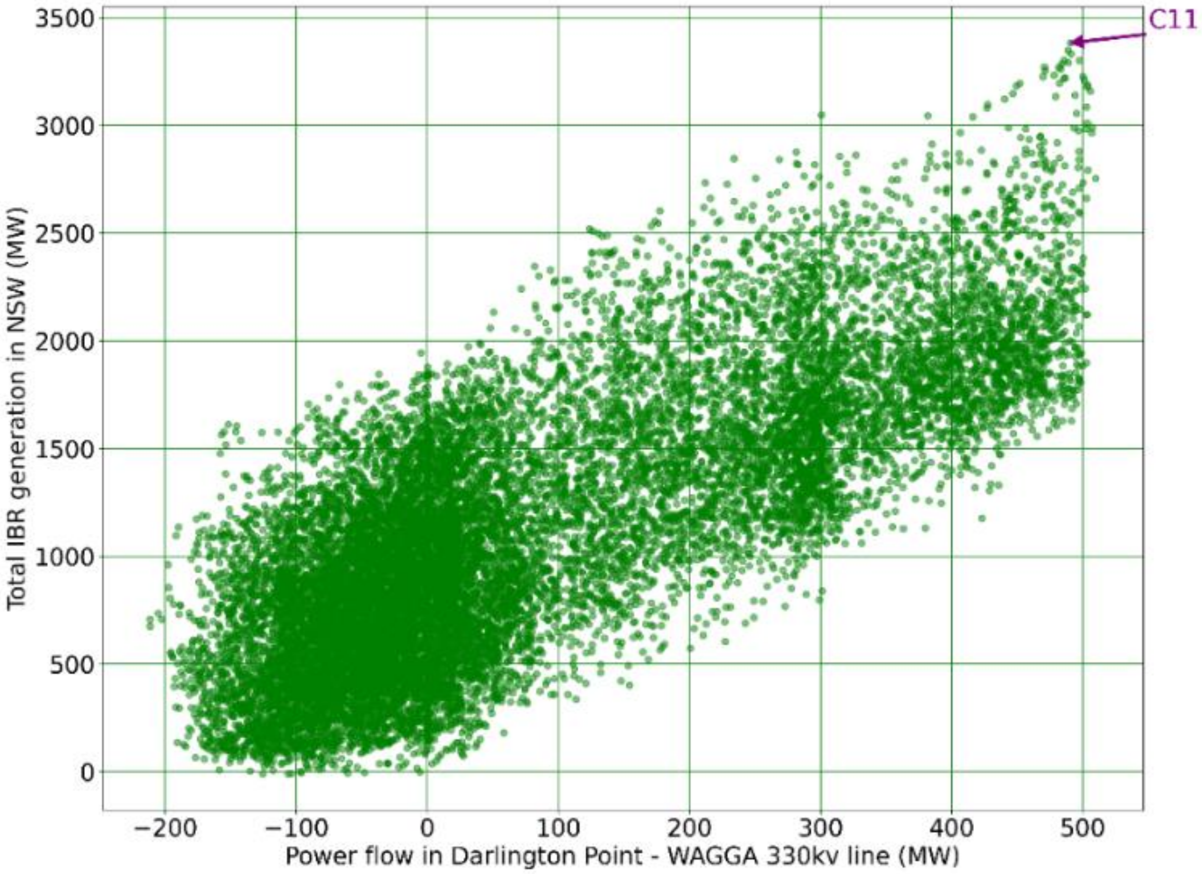


Table 8 Selected snapshots and the corresponding system conditions for Wagga contingency

Case	Timestamp	Flow in line 51 (Wagga - Lower Tumut) (MW)	Flow in line 62 (Wagga - Jindera) (MW)	Flow in line 63 (Darlington Point - Wagga) (MW)	IBR generation near Wagga and Darlington Point regions (MW)	NSW demand (MW)	Total IBR generation in NSW (MW)	DPV in NSW (MW)	DPV in VIC (MW)	Intertripped IBR generation near Wagga and Darlington Point regions (MW)
1	31/01/2022 17:31	321 (42%)	184 (43%)	308 (60%)	1,136 (74%)	10,652 (87%)	1,525 (45%)	729 (21%)	864 (33%)	580
2	17/10/2021 13:01	473 (62%)	-101 (34%)	296 (58%)	799 (52%)	4,090 (0%)	1,437 (43%)	3,162 (91%)	1,643 (62%)	375
3	6/07/2021 18:00	-81 (19%)	116 (27%)	-123 (58%)	0 (0%)	11,569 (100%)	78 (3%)	0 (0%)	0 (0%)	18
4	17/04/2022 12:01	597 (78%)	-44 (15%)	439 (86%)	940 (62%)	4,643 (7%)	1,861 (55%)	2,668 (77%)	1,903 (72%)	710
5	6/06/2022 12:31	386 (50%)	-13 (4%)	332 (65%)	695 (46%)	7,340 (43%)	2,704 (80%)	2,316 (66%)	1,175 (45%)	327
6	17/06/2022 17:31	-229 (53%)	-115 (39%)	-132 (63%)	0 (0%)	10,138 (81%)	140 (4%)	0 (0%)	1 (0%)	18
7	14/12/2021 12:31	431 (56%)	46 (11%)	385 (75%)	1,332 (87%)	5,675 (21%)	1,858 (55%)	3,363 (97%)	2,499 (95%)	735
8	19/01/2022 20:31	86 (11%)	-230 (77%)	-9 (4%)	0 (0%)	7,293 (43%)	1,585 (47%)	0 (0%)	0 (0%)	185
9	2/04/2022 10:31	355 (46%)	43 (10%)	410 (80%)	813 (53%)	5,935 (25%)	1,763 (52%)	2,026 (58%)	579 (22%)	604
10	12/02/2022 14:01	501 (65%)	95 (22%)	481 (94%)	1,517 (99%)	6,146 (27%)	2,229 (66%)	1,768 (51%)	2,300 (87%)	750
11	20/01/2022 10:31	471 (61%)	135 (32%)	490 (96%)	1,311 (86%)	6,813 (36%)	3,383 (100%)	1,825 (52%)	2,322 (88%)	865
12	31/12/2021 11:01	464 (61%)	75 (18%)	445 (87%)	1,221 (80%)	5,568 (20%)	1,989 (59%)	3,311 (95%)	2,414 (92%)	606
13	1/06/2022 13:01	180 (23%)	144 (34%)	283 (55%)	647 (42%)	7,528 (46%)	2,819 (83%)	2,281 (65%)	839 (32%)	373
14	29/08/2021 10:31	84 (11%)	159 (37%)	287 (56%)	655 (43%)	7,039 (39%)	1,205 (36%)	1,406 (40%)	736 (28%)	480
15	30/07/2021 9:01	3 (0%)	142 (33%)	134 (26%)	545 (36%)	8,961 (65%)	1,257 (37%)	1,137 (33%)	442 (17%)	194

Tamworth contingency

The Tamworth contingency is related to the Tamworth double 330 kV bus trip which would incur the QNI instability and followed by the synchronous separation of Queensland from the rest of the NEM. Each snapshot focused on each of following system conditions while other remaining system conditions were optimised to obtain the timestamps for the worst-case scenarios that are available from the trended data.

- High Queensland export.
- High DPV in New South Wales + Victoria.
- High generation near Tamworth.

The individual values of each system condition that relates to the Tamworth contingency for each snapshot are given in Table 9.

Figure 4 Scatter plot of power flow on QNI and total generation near Tamworth for FY 2021-22

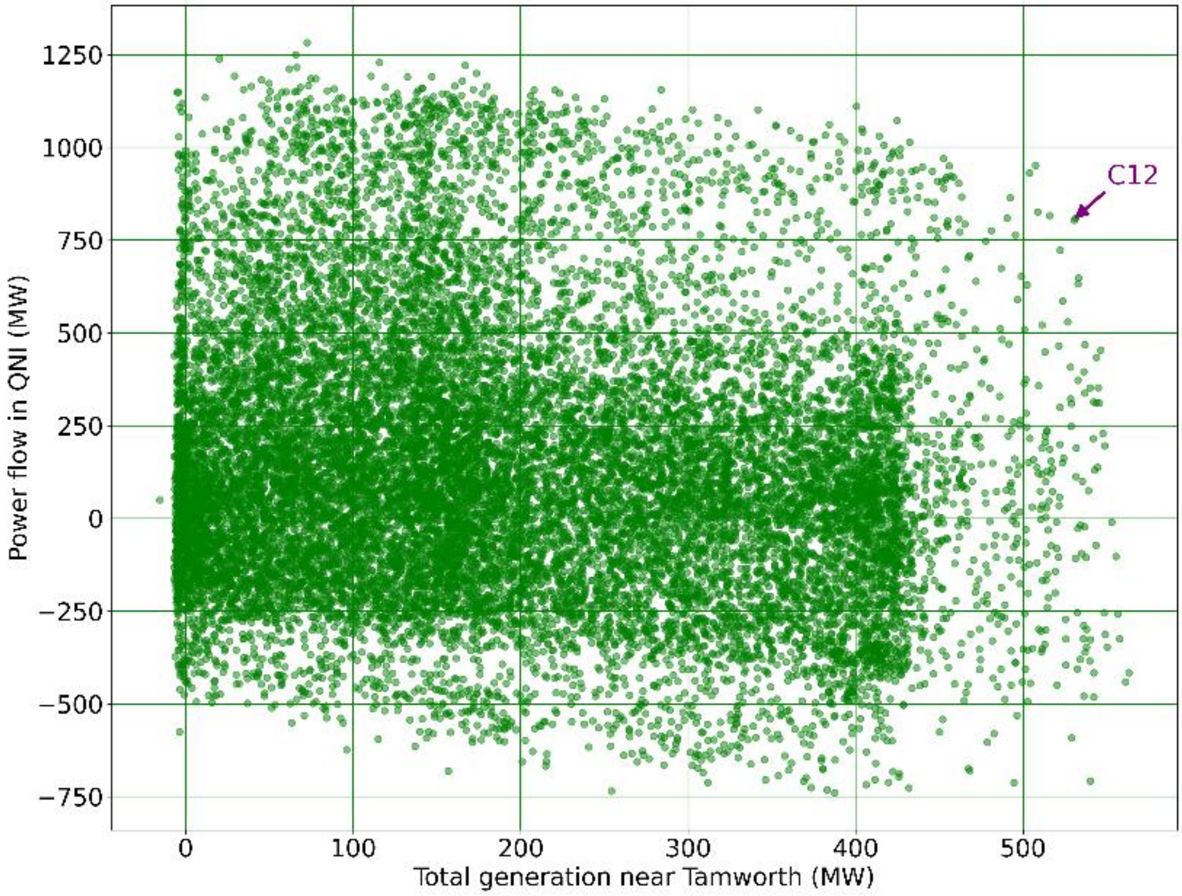


Figure 5 Scatter plot of total DPV generation in New South Wales and Victoria and total generation near Tamworth for FY 2021-22

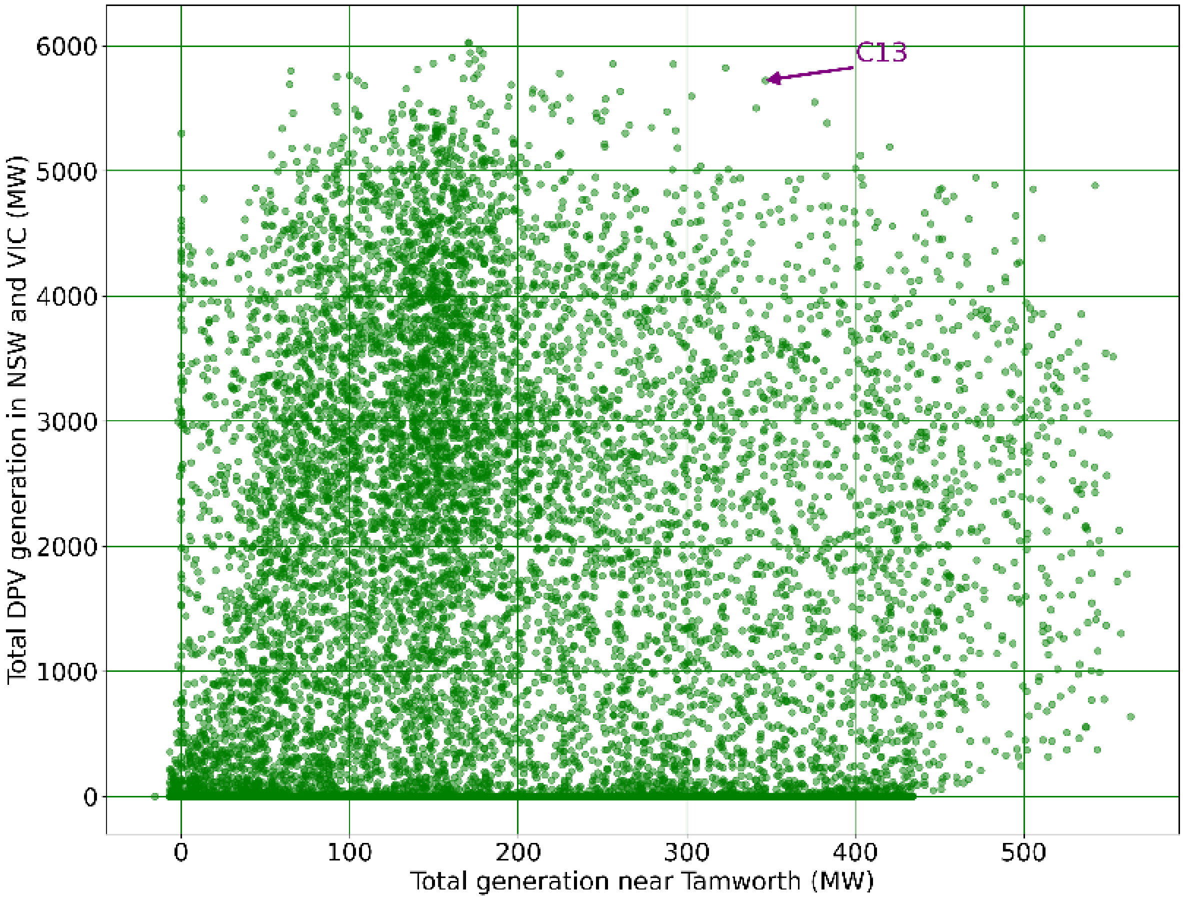


Table 9 Selected snapshots and the corresponding system conditions for the Tamworth contingency

Case	Timestamp	Net generation near Tamworth (MW)	NSW+VIC demand (MW)	IBR generation in NSW+VIC (MW)	DPV in NSW+VIC regions (MW)
1	31/01/2022 17:31	95 (17%)	18,305 (96%)	2,596 (46%)	1,592 (26%)
2	17/10/2021 13:01	116 (21%)	6,918 (3%)	2,138 (38%)	4,805 (80%)
3	6/07/2021 18:00	0 (0%)	18,252 (95%)	155 (3%)	0 (0%)
4	17/04/2022 12:01	142 (25%)	7,121 (4%)	3,518 (63%)	4,571 (76%)
5	6/06/2022 12:31	376 (67%)	12,678 (50%)	5,467 (98%)	3,491 (58%)
6	17/06/2022 17:31	20 (4%)	16,526 (81%)	180 (3%)	1 (0%)
7	14/12/2021 12:31	150 (27%)	9,298 (22%)	2,406 (43%)	5,862 (97%)
8	19/01/2022 20:31	416 (74%)	12,063 (45%)	4,025 (72%)	0 (0%)
9	2/04/2022 10:31	197 (35%)	10,173 (29%)	3,835 (69%)	2,605 (43%)
10	12/02/2022 14:01	187 (33%)	9,333 (22%)	3,295 (59%)	4,068 (68%)
11	20/01/2022 10:31	489 (87%)	10,273 (30%)	4,215 (75%)	4,148 (69%)
12	31/12/2021 11:01	347 (62%)	9,901 (27%)	4,388 (79%)	5,725 (95%)
13	1/06/2022 13:01	531 (94%)	13,632 (58%)	5,365 (96%)	3,119 (52%)
14	29/08/2021 10:31	138 (24%)	11,302 (39%)	1,996 (36%)	2,142 (36%)
15	30/07/2021 9:01	220 (39%)	14,956 (68%)	3,482 (62%)	1,579 (26%)

Mount Piper contingency

The Mount Piper contingency is related to the non-credible loss of Bayswater – Mount Piper (5A3) and Mount Piper – Wollar (5A5) 500 kV lines contingency. The following parameters were taken into consideration when selecting the snapshots:

- The net flow in 5A3 and 5A5 (both northerly and southerly).
- The net flow in parallel corridors 5A3 and 5A5.
- Total generation near Bayswater and Liddell regions.
- New South Wales DPV.
- Total IBR generation in New South Wales.

Note that it was not possible to find snapshots that achieved the historical maximum values simultaneously for all the parameters given above. Therefore, when selecting snapshots, the highest possible value for each parameter while maximizing the net flow in 5A3 and 5A5 was identified. The individual values of each system condition that relates to the Mount Piper contingency for each snapshot are given in Table 10.

Figure 6 Scatter plot of total power flow on 5A3 and 5A5 lines and total flow on parallel corridors for FY 2021-22

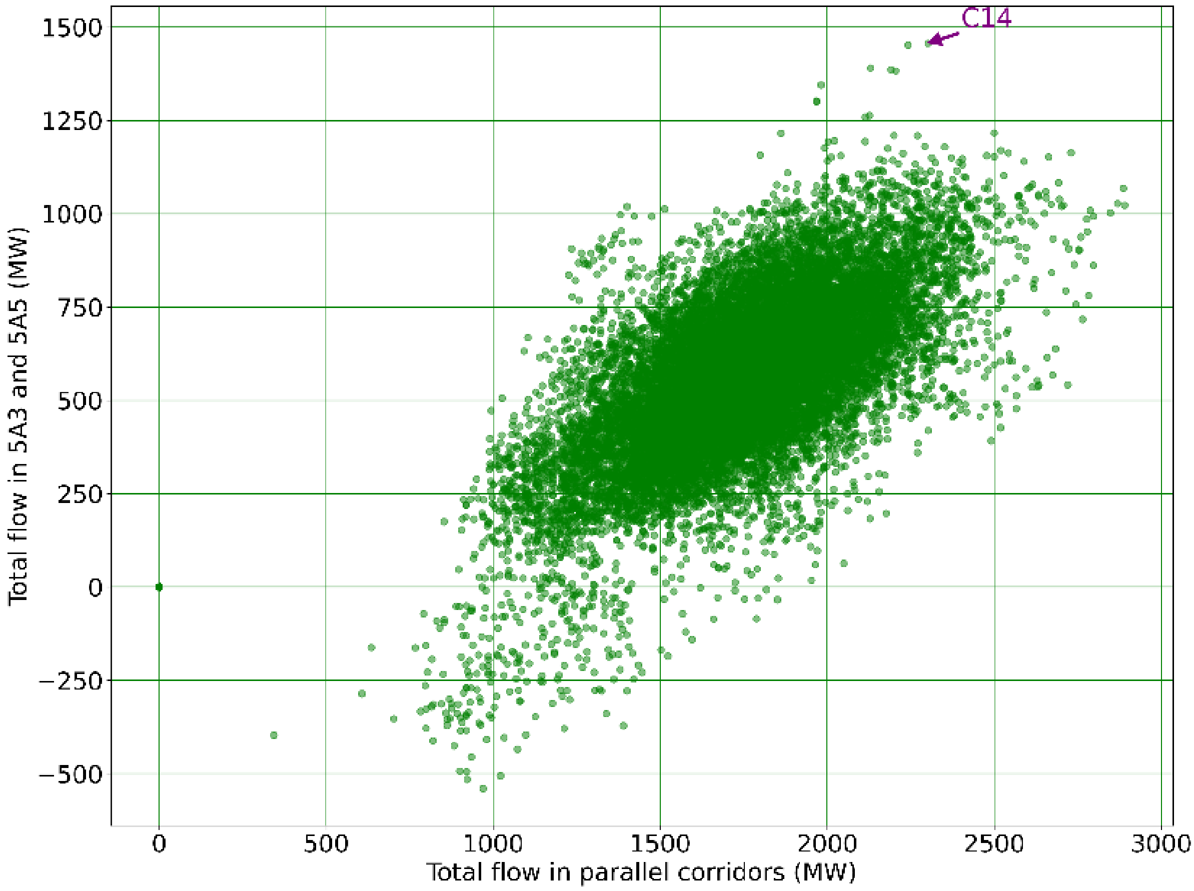


Figure 7 Scatter plot of total generation near Bayswater and Liddell and total flow on parallel corridors for FY 2021-22

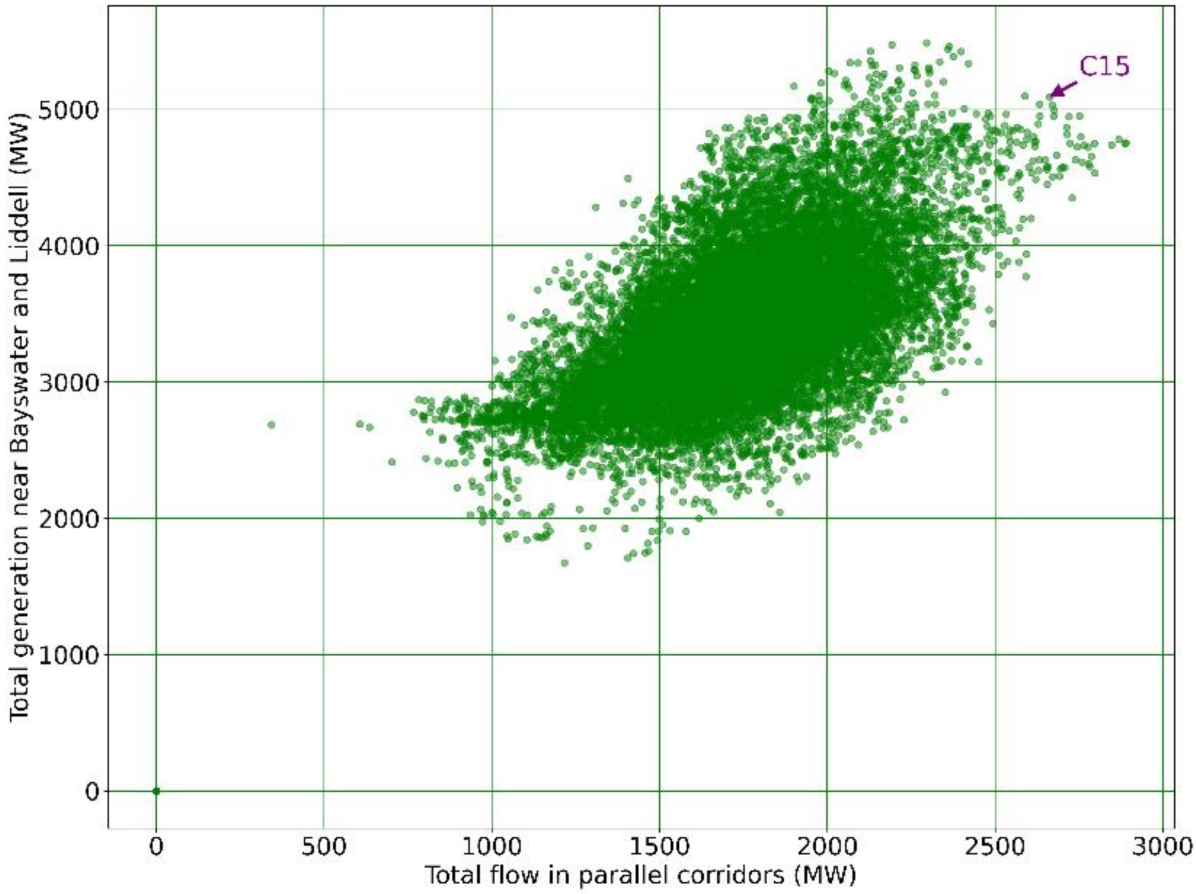


Table 10 Selected snapshots and the corresponding system conditions for the Mount Piper contingency

Case	Timestamp	Net flow in lines 5A3 and 5A5 (MW)	Net flow in parallel corridors to lines 5A3 and 5A5 (MW)	Total generation near Bayswater and Liddell regions (MW)	NSW demand (MW)	Total IBR generation in NSW (MW)	DPV NSW (MW)	DPV VIC (MW)
1	31/01/2022 17:31	370 (25%)	2,054 (67%)	5,214 (93%)	10,652 (87%)	1,525 (45%)	729 (21%)	864 (33%)
2	17/10/2021 13:01	354 (24%)	1,286 (37%)	1,799 (3%)	4,090 (0%)	1,437 (43%)	3,162 (91%)	1,643 (62%)
3	6/07/2021 18:00	585 (40%)	2,594 (88%)	4,782 (81%)	11,569 (100%)	78 (3%)	0 (0%)	0 (0%)
4	17/04/2022 12:01	457 (31%)	1,513 (46%)	2,873 (31%)	4,643 (7%)	1,861 (55%)	2,668 (77%)	1,903 (72%)
5	6/06/2022 12:31	672 (46%)	1,827 (58%)	3,394 (45%)	7,340 (43%)	2,704 (80%)	2,316 (66%)	1,175 (45%)
6	17/06/2022 17:31	300 (21%)	1,840 (59%)	3,103 (37%)	10,138 (81%)	140 (4%)	0 (0%)	1 (0%)
7	14/12/2021 12:31	602 (41%)	1,658 (52%)	3,095 (37%)	5,675 (21%)	1,858 (55%)	3,363 (97%)	2,499 (95%)
8	19/01/2022 20:31	628 (43%)	1,967 (64%)	4,067 (63%)	7,293 (43%)	1,585 (47%)	0 (0%)	0 (0%)
9	2/04/2022 10:31	460 (32%)	1,646 (51%)	3,184 (40%)	5,935 (25%)	1,763 (52%)	2,026 (58%)	579 (22%)
10	12/02/2022 14:01	546 (38%)	1,818 (58%)	3,184 (40%)	6,146 (27%)	2,229 (66%)	1,768 (51%)	2,300 (87%)
11	20/01/2022 10:31	473 (32%)	1,697 (53%)	3,455 (47%)	6,813 (36%)	3,383 (100%)	1,825 (52%)	2,322 (88%)
12	31/12/2021 11:01	652 (45%)	1,916 (62%)	3,162 (39%)	5,568 (20%)	1,989 (59%)	3,311 (95%)	2,414 (92%)
13	1/06/2022 13:01	1,116 (77%)	2,278 (76%)	3,661 (52%)	7,528 (46%)	2,819 (83%)	2,281 (65%)	839 (32%)
14	29/08/2021 10:31	1,457 (100%)	2,301 (77%)	3,579 (50%)	7,039 (39%)	1,205 (36%)	1,406 (40%)	736 (28%)
15	30/07/2021 9:01	1,152 (79%)	2,663 (91%)	5,093 (90%)	8,961 (65%)	1,257 (37%)	1,137 (33%)	442 (17%)

A3.2 Future cases methodology

A3.2.1 Network model

Network development path

The 2022 ISP and its optimal development path support Australia's complex and rapid energy transformation towards net zero emissions. The 2022 ISP *Step Change* scenario was considered by energy industry stakeholders to be the most likely scenario to play out[33]. Consequently, forecasting data from the 2022 ISP *Step Change* scenario has been used in the 2023 GPSRR for future projections. These projections included ISP committed, anticipated and actionable projects in the next five years, as listed in Table 11[34]. Closures of power stations such as Liddell Power Station (2022 and 2023) and announced potential closure of Eraring Power Station (2025) have been included in the modelling considered in future studies.

Table 11 Committed, anticipated and actionable major transmission projects to June 2028

Project	Deliverable date	Status
VNI Minor	November 2022	Committed
Eyre Peninsula Link	Early 2023	Committed
QNI Minor	Mid-2023[A]	Committed
Northern Queensland Renewable Energy Zone (QREZ) Stage 1	September 2023	Anticipated
Central West Orana REZ Transmission Link	Mid-2025	Anticipated
Project EnergyConnect (PEC)	July 2026[B]	Anticipated
Western Renewables Link (WRL)	July 2026	Anticipated
HumeLink	July 2026	ISP Actionable Project
Sydney Ring	July 2027	NSW Actionable Project[C]
New England REZ Transmission Link	July 2027	NSW Actionable Project [C]

A. This timing is when full capacity is expected to be available following commissioning and interconnector testing.
B. This projected delivery date for PEC refers to full capacity available following completion of inter-regional testing.
C. Sydney Ring and New England REZ Transmission Link are actionable under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.

Five-year ahead (2027-28) studies were carried out using a simplified NEM network model which includes the QNI minor and the PEC Stage 2 upgrades. VNI is represented as two single-circuit lines in the simplified model, meaning it is not fully represented as per the OPDMS full model – this simplification does not significantly impact the model accuracy for the risks being studied as part of the 2023 GPSRR. Importantly, the use of a simplified NEM model enabled the assessment of a wider range of future dispatch scenarios and contingencies. This approach is consistent with that used for the 2022 PSFRR future studies. AEMO used a full NEM model based on an OPDMS snapshot which include the new interconnectors that are planned for completion by June 2028 (see Table 11), to benchmark the simplified model.

This GPSRR considered ISP FY 2027-28 *Step Change* scenarios for future studies. The following 2028 *Step Change* forecast data was considered by AEMO when setting up the future study cases:

[33] See Section 2.3 of the 2022 ISP, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

[34] See Section 5.3 and 5.4 of the 2022 ISP, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en. All dates are based on current schedules as advised to AEMO and may change.

- Maximum and minimum regional demands.
- Maximum and minimum IBR generation.
- Projected DPV generation.
- Projected UFLS availability.
- Decommissioning of synchronous generators.
- Future studies were completed assuming a system normal network configuration[35]. The key system forecast parameters that were considered in setting up the study cases are included in Section 4. A standard set of 12 future dispatches was studied for each contingency.

A3.2.2 Assumptions and limitations of the simplified NEM model

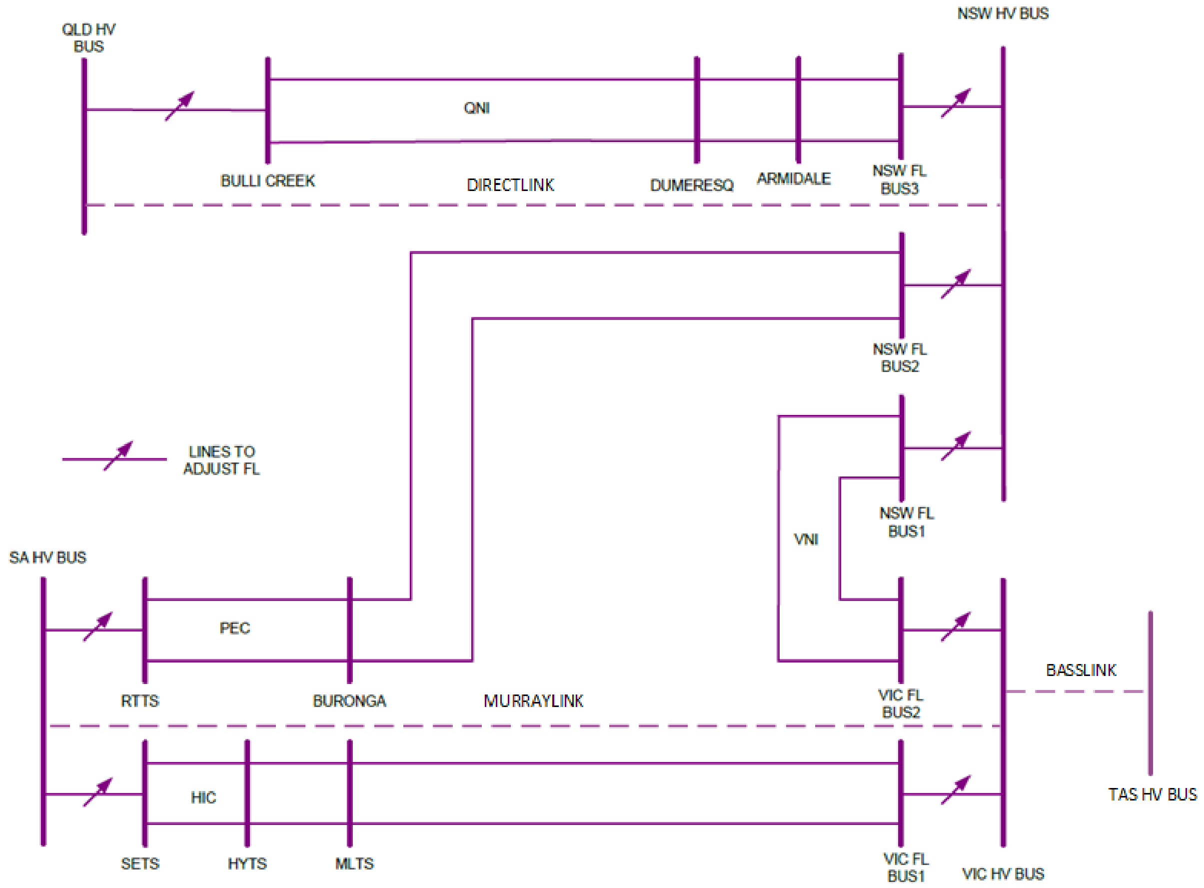
For the simplified NEM model, the following network configuration and modelling approaches are used:

- Each mainland region is represented by a common high voltage bus (New South Wales, Victoria and Queensland 330 kV and South Australia 275 kV buses). All the regional generators are assumed to be connected to these regional common buses through appropriate generator transformers.
- Regional generators are lumped as steam, gas, hydro, wind and solar with appropriate generic models such as alternator, voltage controller, governors and IBR controllers included with the lumped generators according to each generator type.
- UFLS and underlying DPV are grouped according to their frequency trip bands and connected at medium voltage (MV) buses:
  - 121 New South Wales UFLS bands.
  - 32 Victoria UFLS bands.
  - 33 Queensland UFLS bands.
  - 30 South Australia UFLS bands.
- The grouped UFLS and DPV feeders are also connected to common high voltage buses through appropriate transformers.
- Interconnectors (aside from VNI) are modelled as per OPDMS network with compensating devices, such as reactors, capacitors, and static volt-ampere reactive (VAR) compensators (SVCs).
- PEC Stage 2 (and the associated SPS) is included based on the latest planning information available (at the time of study).
- The high voltage (HV) network between South East Switching Station (SESS) and MLTS, and between Robertstown Terminal Station (RTTS) and Buronga is modelled as per OPDMS network.
- South Australia generators and generators connected between HYTS and MLTS are modelled as per OPDMS including their dynamic models.
- APD network loads are modelled as per the OPDMS.

[35] System normal snapshots restore the nominal configuration of the network. Network outages (planned or unplanned) are restored to the nominal configuration whilst generation and load are retained as they were in the snapshot timestamp. In the future studies the load and generation will be redispatched, and network projects will be added to match the forecast network conditions.

- The South Australian OFGS generators are modelled as per OPDMS generator models for the respective plants along with their existing OFGS trip settings.
- A single line diagram of the simplified model including PEC Stage 2 is shown in Figure 8.

Figure 8 Simplified single line diagram of the updated simplified NEM model with PEC Stage 2 integrated



Even though the simplified network can capture frequency variations with reasonable accuracy, it is impacted by the following limitations:

- The model excludes actual network impedances (aside from interconnectors, which are modelled as per OPDMS as detailed above), therefore, it cannot accurately predict power system voltages.
  - The model provides an approximation of fault ride-through characteristics of IBR plant.
  - The model provides an approximation of the voltage-based tripping behaviour of DPV. As detailed in Section 4.1, for the future studies using the simplified model, the voltage response of DPV was emulated by force tripping a fixed percentage of regional DPV based on findings from AEMO’s previous studies.
- The power swings on interconnectors and their angular stability predictions may be optimistic when compared with the full NEM OPDMS model. To estimate the accuracy of the simplified model used for the 2023 GPSRR studies, the model responses were benchmarked against responses from the full NEM OPDMS model. The results of this benchmarking are detailed in Appendix A4. Specifically, the fault levels at key system nodes in

the simplified model were matched with the full NEM model and the accuracy with which the simplified model could predict QNI instability was assessed.

A3.2.3 Integration of HVDC interconnectors

Following the completion of the benchmarking process detailed in Appendix A4, the OPDMS models for the Basslink line commutated converter (LCC) HVDC interconnector, and the Murraylink and Directlink voltage-sourced converter (VSC) HVDC interconnectors were integrated into the simplified model.

A3.2.4 Special protection scheme (SPS) models

The SPS models that were considered in the GPSRR future studies are outlined in Table 12.

Table 12 List of SPSs used in future studies

Model	Region	Model owner	Status
EAPT scheme	VIC	AVP	Future studies: Assumed performance and topology-based operation (Mode 1).
SAIT RAS	SA	ElectraNet	ElectraNet/Transgrid are presently developing the scheme, in consultation with AEMO (not available). Future studies: An approximate SPS action (based on advice from ElectraNet) assumed since SPS design is not completed at this stage.

A3.2.5 Over frequency generation shedding (OFGS)

The OFGS models for South Australian generators were used in both OPDMS and simplified NEM models. The proposed Queensland OFGS was not modelled (see the section below for more details). AEMO completed a review of the South Australia OFGS in Q4 2022 and recommended that an increase in OFGS capacity was required to improve system performance for over-frequency events. Details of this additional capacity are yet to be finalised, and the islanded performance of South Australia was not studied in detail as part of the 2023 GPSRR, so it was not included in the modelling for the GPSRR future studies.

A3.2.6 Queensland over frequency generation shedding (OFGS)

Studies of the separation of Queensland through loss of QNI completed as part of the 2022 PSFRR showed that when Queensland is exporting, frequency in Queensland could rise above 52 Hz following the loss of QNI. To help mitigate this risk AEMO is collaborating with Powerlink to develop an OFGS scheme for Queensland. During the 2022 PSFRR consultation period, AEMO identified a need to undertake additional sensitivity studies with IBR frequency control disabled for historic studies where there is a risk of over-frequency. These studies showed that a maximum 0.51 Hz further increase in Queensland peak frequencies following QNI separation is possible, reinforcing the recommendation for a new OFGS scheme for Queensland. AEMO may disable (modelled) IBR frequency control during the design of the Queensland OFGS scheme.

The details of the Queensland OFGS scheme are yet to be finalised and Queensland separation for Queensland export conditions was studied in detail as part of the 2022 PSFRR. Therefore, an OFGS scheme in Queensland was not modelled for the 2023 GPSRR future studies, as the focus of the studies was determining what non-credible contingencies across the mainland NEM could lead to QNI instability rather than the stability of Queensland following separation.

A3.2.7 Future studies load modelling

The CMLD was used to model the load response in the GPSRR historical studies that utilised the OPDMS full NEM model. However, as detailed in Appendix A3.2.2 and Appendix A4, given that the simplified NEM model does not accurately capture severe voltage disturbances, only shallow faults were studied using the simplified model. Therefore, it is not necessary to capture load shake off in response to large disturbances in the simplified NEM model. Additionally, the frequency dependent load relief in the NEM is minimal (currently assumed to be 0.5%) and is projected to reduce into the future due to the increase in inverter loads[36]. Therefore, a traditional polynomial static load (ZIP) model was used to represent NEM loads in the simplified model.

A3.2.8 Simulation of Risk 4a: South Australia separation at Moorabool Terminal Station (MLTS)

V^^V_NIL_SWVIC constraint

In September 2022, the V^^V_NIL_SWVIC constraint was implemented to manage MLTS – HYTS flows to avoid voltage instability for the loss of the Haunted Gully to Moorabool 500 kV line and both APD potlines. This constraint was not explicitly considered as part of these studies as it was not included in the forecasting data assumptions. However, high-level Power-Voltage analysis completed previously indicated that, in some scenarios, voltages at the 500 kV buses near MLTS could fall to around 0.9 p.u. when the line between Haunted Gully and MLTS was disconnected when there were flows from MLTS to Heywood of above 1,800 MW. Therefore, MLTS – HYTS flows of up to approximately 1,800 MW were considered as part of these studies.

South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS)

ElectraNet is currently designing a special protection scheme – SAIT RAS – to enable maximum transfer on PEC and Heywood interconnectors, while avoiding South Australia islanding in the event of a non-credible loss of either PEC or Heywood interconnector causing transient instability on the remaining interconnector[37]. At the time of this study, specific details of the planned SPS are not available, however, the study assumes a simplified SPS action through South Australian load and generation tripping. Time delay for the SPS trigger was assumed to be 250 ms. South Australian UFLS and OFGS were also modelled.

Based on the latest advice from ElectraNet, the SAIT RAS was assumed to be a topological-based scheme that trips an amount of load (for South Australia import conditions) or generation (for South Australia export conditions) that is calculated based on the level of South Australia import/export. The import/export threshold for the SPS was assumed to be 800 MW, with a difference value of 750 MW. Therefore, if the total South Australia import/export exceeds 800 MW, the amount of load/generation that is tripped by the scheme is equal to the South Australia import/export level minus 750 MW. Note that the tripping of PEC in the event of the loss of synchronism/angular separation of South Australia to island South Australia was not simulated.

[36] Load relief is an assumed change in load that occurs when power system frequency changes. It relates to how particular types of loads (particularly traditional motors, pumps, and fans) draw less power when frequency is low, and more power when frequency is high. AEMO is acting on a recent review of load relief in the NEM. Accordingly, from September 2019, AEMO slowly reduced assumed mainland load relief from 1.5% to its current value of 0.5%, with a review point at 1%. Subsequently, AEMO's analysis of power system events in the mainland during 2020 confirmed that a load relief value of 0.5% remains appropriate at this stage for the mainland NEM.

[37] As part of this process ElectraNet, Transgrid and AEMO (in its role as the Victorian transmission planner) are reviewing relevant existing emergency control schemes to determine if changes are needed due to PEC.

Emergency Alcoa-Portland Potline Tripping (EAPT) Scheme

The EAPT scheme is designed to detect loss of 500 kV connection between Heywood and Moorabool and trip the Heywood to South East lines at Heywood, effectively separating the SA region at HYTS. Also, when the PSS®E model detects the loss of 500 kV connection between Heywood and Moorabool, it trips the Heywood to Moorabool/APD lines at Heywood to prevent the Victorian generators between Moorabool and Heywood feeding the APD smelter load in islanded mode.

AEMO has completed the review of EAPT scheme and updates to the existing scheme to improve effectiveness, particularly around topology, and they were completed at the end of FY 2021-22. The updated EAPT model was included for the GPSRR future studies, with the normally enabled Mode 1 selected. In Mode 1, the EAPT scheme operates as a combination of a topology-based and performance-based scheme.

South-West Victoria Generator Fast Trip (GFT) Scheme

Normally enabled, the scheme automatically disconnects Dundonnell WF and Stockyard Hill WF for a variety of contingencies, including a double-circuit outage on the 500 kV lines into Moorabool. The primary trip time is 170 ms. For the PSS®E studies, when a double circuit 500 kV line trip was simulated, Dundonnell WF and Stockyard Hill WF were disconnected within 170 ms of a 500 kV double line contingency.

Lake Bonney Wind Farm and inter-trip scheme

The PSCAD™ models of Lake Bonney WF 1-3 and Canunda WF, which have been provided to AEMO to represent these generating units in power system studies show that these plants can become unstable and trip following a credible or non-credible separation between Heywood and Moorabool 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.

Iberdrola has requested that the Lake Bonney WF be added to an inter-trip 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 could be eased, although other constraints designed to manage the loss of the wind farm's generation will be required. The models used for the GPSRR future studies assume that the Lake Bonney trip scheme operates within 200 ms[38]. Note that the details of the scheme are still being determined.

Macarthur Wind Farm RoCoF relays

Protection relays for selected collector groups at Macarthur WF are set to trip when RoCoF is more than 2.5 Hz/s or 3.0 Hz/s for a specific time. This RoCoF relay type is not available in the PSS®E standard library as well as the standard AEMO base case. Hence, these relays were not included in these studies. The results show that RoCoF did not exceed 2.5 Hz/s for any cases studied.

Alcoa-Portland (APD) load voltage tripping

A fault 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. This reclassification is managed via constraints designed to manage both over-frequency and network loading risks if APD were to trip following the

[38] This is a comparable operation time to the Generator Fast Trip (GFT) scheme already implemented in South-West Victoria (Section 0), which operates in 170ms. The Lake Bonney trip scheme has been assumed to operate within a similar timeframe as it uses similar technologies.

loss of the lines. However, the likelihood of APD tripping on a voltage disturbance is challenging to quantify and may depend on the location and type of 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. Therefore, sensitivities tripping the APD loads following fault clearance were completed for cases with South Australia export conditions where EAPT did not operate.

A3.3 Dynamic modelling

A3.3.1 Distributed PV model

The DERAEMO1 model developed by AEMO was used to model the dynamic behaviour of the DPV generation modelled in the full OPDMS cases[39]. A single instance of the DERAEMO1 model was connected to each transmission bus, as shown in Figure 1 in Appendix A3.1.5. This single model represents the aggregate behaviour of all DPV connected downstream of that transmission bus, which includes a proportion of DPV installed under different AS4777 standards (and therefore demonstrating different behaviours). Each of the 134 parameters in the DERAEMO1 model has been calibrated to represent the total aggregate behaviour of the DPV connected downstream of that bus, depending on the composition of DPV installed.

A3.3.2 Frequency control ancillary services (FCAS) response

Unless stated otherwise, FCAS response of synchronous generators was not considered in the studies apart from the frequency responses provided by PFR governors. The FCAS lower capabilities of IBR was considered according to PFR settings, if PFR commissioning is completed. The PFR capability of IBR plants was not considered if confirmation of frequency control enablement from the generator was not available at the time of the study.

A3.3.3 Queensland to New South Wales Interconnector (QNI) distance protection

To be able to model the tripping of QNI in response to instability, the distance protection relays for QNI at Bulli Creek and Dumaresq were modelled using the RXR1 and DISTR1 PSS®E library models based on data supplied by Transgrid and Powerlink. It is important to note that these library models are not able to capture all of the settings of the actual QNI distance protection relays at Bulli Creek and Dumaresq. As such, further studies are needed to fully model the operation of the distance protection relay under varying operation conditions as part of the scoping and design of a QNI SPS.

A3.4 Risk cost assessment methodology

This section describes the methodology used in 2023 GPSRR to estimate the risk-cost of each identified risk. This risk-cost methodology is used to quantify key risks in monetary terms. A simplified quantitative approach can be used considering each risk consequence and likelihood as shown below:

[39] See https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

Risk = consequence x likelihood occurrence (or probability)

The risk cost can be determined by calculating the cost of the risk consequence. For the 2023 GPSRR the cost of a severe risk was calculated as the total interrupted of loads (measured in MWh) multiplied by the value of customer reliability (VCR)[40] and the estimated time to restore interrupted load following the event (T). The VCR was published at $43.23/kWh by the AER for year 2019 and it is required to be adjusted to the relevant year where the risk cost is calculating based on the CPI.

The likelihood of a severe risk event has two components:

- Probability of the risk event (Pc), Pc can be determined using the historical data; and,
- The probability of network conditions which, in combination with the risk event, cause the consequence to occur (Pe). Detailed power system studies combined with dispatch forecasts are required to determine Pe.
- Therefore, the above formula can be expanded to:

Risk cost = L x T x VCR x Pc x Pe

Where:

L is the MW loss (interrupted) due to a non-credible contingency

T is the time to restore the interrupted loads following the event

VCR value of the unserved energy during the interruption

Pc is the probability of a risk event

Pe is the likelihood of the network condition is exposed to a consequence following a non-credible event.

A3.5 Option assessment methodology

In accordance with NER 5.20A.1(c)(2)(i), AEMO is required to assess options for future management of the priority risks that are technically and economically feasible and assess the expected costs and time for implementation of each option.

Once the indicative risk cost has been established, AEMO, in collaboration with relevant stakeholders, will assess alternative solutions which can eliminate or reduce the risk of a risk event.

Solutions considered may include:

- New or modified special protection scheme – which takes post event actions to reduce the likelihood or severity of the risk.
- Declaration of the event as a protected event – which are likely to use ex-ante measures such as constraints to maintain power system security for the risk event.

[40] AER 2019, Values of Consumer Reliability – Final Decision, Table 5.22, at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf.

- Network augmentations.
- Non-network alternatives to augmentation.

The solutions are then filtered through a screening assessment to select preferred solution(s) for investment. Factors considered in the screening assessment may include:

- Cost.
- Effectiveness at addressing the risk.
- Time to implement.
- Design life.
- Other factors.

Investment decision-making

Once the solution screening assessment identifies the preferred solution(s), the below formula is used to identify whether each solution is likely to have a market benefit.

To recommend a solution for further assessment, the total cost of the solution should be less than the net present value[41] of the total risk cost savings realised by the solution.

$$\textbf{Investment Cost} \ll \textbf{NPV}\sum_{1}^{t} \boldsymbol{Risk\ cost}$$

Where

NPV is the net present value

t is the economic life of the investment

Risk Cost is the annual risk cost

[41] Net present value uses the present value of money to compare future options on an equal basis, due to inflation or deferred cost.

A4. Future simplified model benchmarking

A4.1 Fault level benchmarking

The benefits of establishing correct fault levels at regional busbars are:

- More accurate network impedance representation – a purpose of accurate fault level benchmarking was to attempt to establish relationships between interconnector tripping and system instability, for example where tripping of the Heywood interconnector would result in instability on QNI due to power swings.
- More accurate voltage step changes observed – this was important in order to simulate accurate DPV tripping for each region due to a contingency event, particularly in regions close to the contingency where high voltage step changes could be observed after a fault event, causing tripping.

For fault level benchmarking in Queensland and South Australia, the dummy impedances between the generator busbars and the fault level “FL” busbars were modified for each region – refer to Figure 8. Establishing correct fault levels at Queensland and South Australia busbars can be accomplished solely by changing “dummy impedance” values in all of the benchmarked studies undertaken. After fault levels at Queensland and South Australia are established, it can be assumed that:

- Fault level contribution of Queensland to Tamworth is broadly accurate when compared to wider NEM model.
- Fault level contribution of South Australia to Moorabool is broadly accurate when compared to wider NEM model.

The process of establishing accurate fault levels for Queensland and South Australia compared to fault levels observed in the wider NEM model was accomplished by modifying X and R of a single line for each region.

However, due to the configuration of the simplified model, it was determined that it was not possible to establish accurate fault levels at the New South Wales and Victoria FL busbars in the simplified model using this same approach:

- Fault level at New South Wales and Victoria busbars in the simplified model is influenced significantly by New South Wales generation and Victoria generation.
- The NSWFLBUS and VICFLBUS are separated by impedances representing VNI, however in practice these FL buses are electrically adjacent to Tamworth and Moorabool, in the far north and south of the network, and therefore these buses are not separated by the total impedance in each case.
- Due to the lumped nature of the generators connected to each FL bus, impedances cannot be distributed across the potential dummy circuits in order to entirely accurately represent network impedance in relation to generators.

Hence, three different approaches to establish correct fault levels at New South Wales and Victoria were tested:

i. Modification of the dummy impedances separating each respective bus from their generators. This did not result in accurate fault levels at Moorabool or Tamworth, as each remained influenced by both regions, resulting in higher fault levels than necessary. Additionally, issues were observed during dynamic simulation due to the high impedances required to reduce fault level, with some instability observed.

ii. Modification of dummy impedances and generator impedances to reduce fault levels. This was able to reduce fault levels at Moorabool and Tamworth closer to those observed in the full NEM OPDMS cases, however the continued influence of Victoria fault level on fault level in New South Wales and vice versa meant that accurate fault levels could not be established on both busbars.

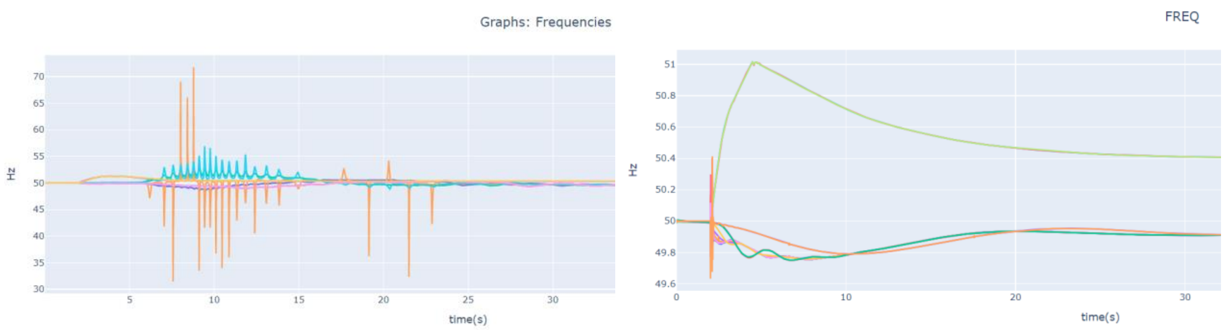
iii. A combination of approaches i and ii:

- Measure the initial FL at relevant Victoria and New South Wales busbars in the historical benchmarked case.
- Separate VNI in historical benchmarked case in order to establish correct contribution to New South Wales and Victoria.
- Separate VNI in simplified model and change generator impedances at New South Wales and Victoria in order to establish correct contributions.
- Reconnect VNI and change impedance between regions in the simplified model to get relative correct FL at New South Wales/Victoria.
- Tune the voltage profile by taking reactive plant in/out of service as needed.

The preferred option was identified as iii. While this preferred approach was sufficient to establish accurate fault levels at New South Wales and Victoria, this did not result in the simplified model replicating the performance of the wider model. With the impedance between Victoria and New South Wales increased too high, the simplified model was observed to become unstable after a contingency event that did not cause an issue with the full PSS®E model due to generator controllers losing stability.

Therefore, establishing accurate fault levels at the New South Wales and Victoria FL buses in the simplified model by adjusting the dummy circuit impedances is an iterative process that did not appear to result in a greater level of accuracy compared to the full NEM OPDMS model for cases studied. Consequently, the optimal strategy when using the simplified model was to establish correct fault levels at Queensland and South Australia busbars, to more accurately model DPV tripping due to voltage changes, and to neglect fault level benchmarking of the central regions.

Figure 9 Frequency performance – unstable simplified model (left) vs stable full model (right)



A4.2 Benchmarking with 2022 PSFRR historical study results

As part of the 2023 GPSRR, AEMO completed benchmarking of specific contingency events assessed against results of historical studies completed for the 2022 PSFRR using a modified full NEM OPDMS model.

The simplified model cases were prepared by:

- Switching out the reactive compensation equipment used for future planning studies, such as the QNI minor upgrade SVCs at Dumaresq, Armidale and Tamworth.
- Applying the generator dispatch setpoints in South Australia and Victoria where they are specifically represented in the simplified model.
- Applying the operational demand levels in each region of the simplified model.
- Specifying the interconnector flows.
- Applying the generation mix (separated into gas, hydro, steam, wind and solar) split by percentage per region.
- Specifying the aggregate inertia (megawatts-seconds (MWs)) for each NEM region in the simplified model.
- Setting the status of special protection scheme loads.

A number of the contingencies studied as part of the 2022 PSFRR were used for the benchmarking of the simplified model, including:

- Separation of South Australia through loss of Heywood – South East 275 kV lines.
- Separation of South Australia at MLTS.
- Loss of the VNI.

These contingencies were studied for multiple historical operating conditions, with the simplified model responses benchmarked against the results obtained using the full NEM OPDMS model for the 2022 PSFRR.

A4.2.1 Separation of South Australia through loss of Heywood – South East 275 kV lines

South Australia, Queensland export cases

Export Case 1

For Export Case 1, considering South Australia separation at HYTS when South Australia was exporting, the following observations were made:

- Significant over frequency observed in South Australia for each model, with the OPDMS full NEM model showing a peak at 51 Hz, and the simplified model showing a peak at 51.2 Hz.
- Frequency recovery is similar in both models, and final settling frequencies are 50.4 Hz in South Australia.
- In the simplified model case, six generators were tripped as part of the OFGS scheme in South Australia, likely due to the greater frequency excursion observed. The generation tripped represented a total of 193 MW.
- In the OPDMS full NEM model case, three generators were tripped as part of the OFGS scheme in South Australia. The generation tripped represented a total of 87 MW disconnected.
- 97 MW of DPV was tripped by inverter settings in the OPDMS full NEM model in South Australia compared to 100 MW in the simplified model.

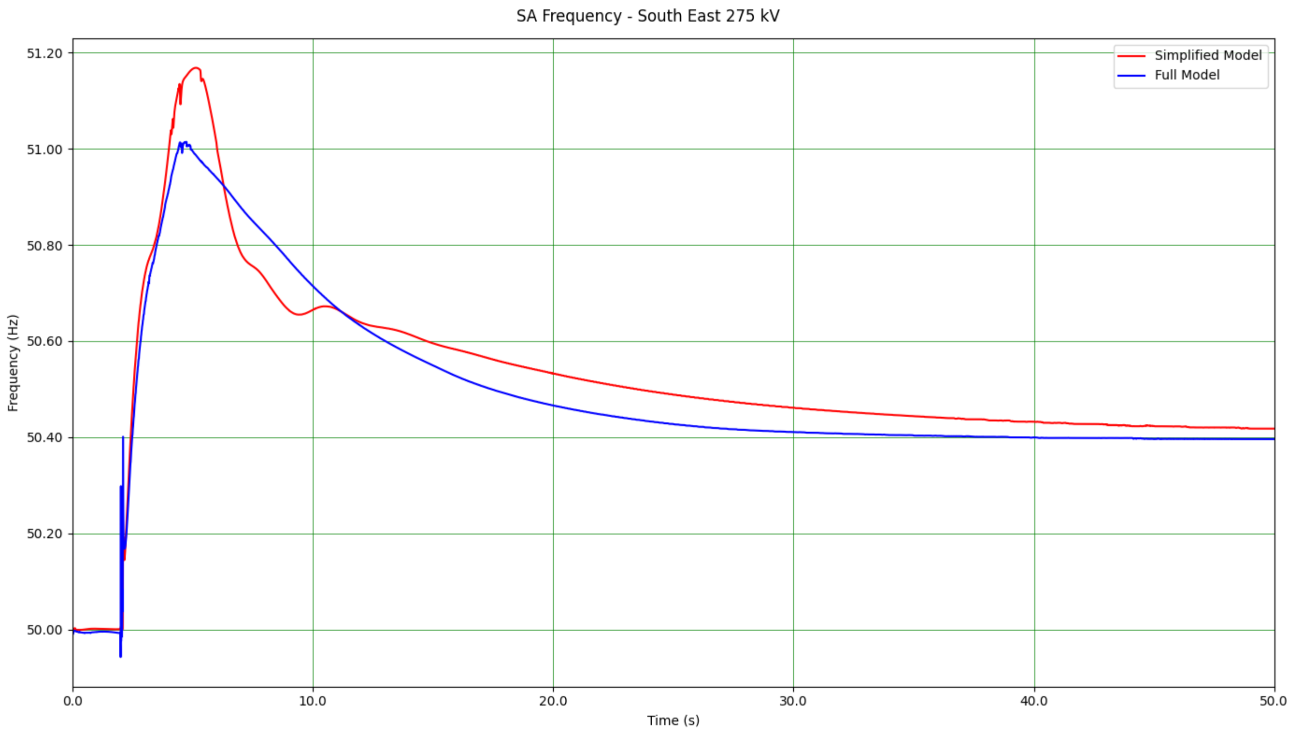
Table 13 Benchmarking results for 2022 PSFRR historical Export Case 1, South Australia separation at Heywood

2022 PSFRR historical Export Case 1, SA separation at HYTS				
Model	SA frequency peak (Hz)	SA OFGS generation tripped (MW)	DPV tripped on inverter settings only (MW)	Was the case stable? (Yes/No)
OPDMS full NEM model	51	193	97	Yes
Simplified NEM model	51.2	87	100	Yes

For this case, fault level tuning did not result in a significant improvement in the frequency response of the model in South Australia. There was no change in DPV shake-off and OFGS tripping due to the fault level tuning process. This was because relatively minor impedance changes were required to achieve alignment between fault levels at South Australia in OPDMS and the simplified model for this case, and therefore the voltage disturbance seen by the DPV was not significantly impacted.

Hence, as frequency in the NEM, and particularly South Australia, is heavily influenced by both DPV shake off and the OFGS scheme, it remains important that accurate fault levels are modelled, in order to establish a credible amount of DPV tripped.

Figure 10 Simplified PSS®E model and OPDMS full NEM PSS®E model SA frequency, SA separation at HYTS, Export Case 1



Export Case 11

Export Case 11 was chosen as a case that exhibited QNI instability following South Australia separation at HYTS in the OPDMS full NEM model. The contingency resulted in a significant power increase on QNI, which was already exporting near peak capacity from Queensland. This caused QNI to lose stability, which then resulted in an unstable case.

Figure 11 OPDMS full NEM PSS®E model, QNI power flow, SA separation at HYTS, Export Case 11

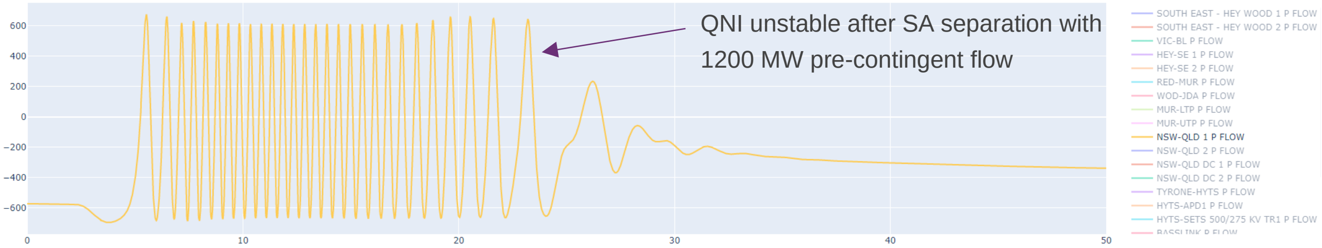
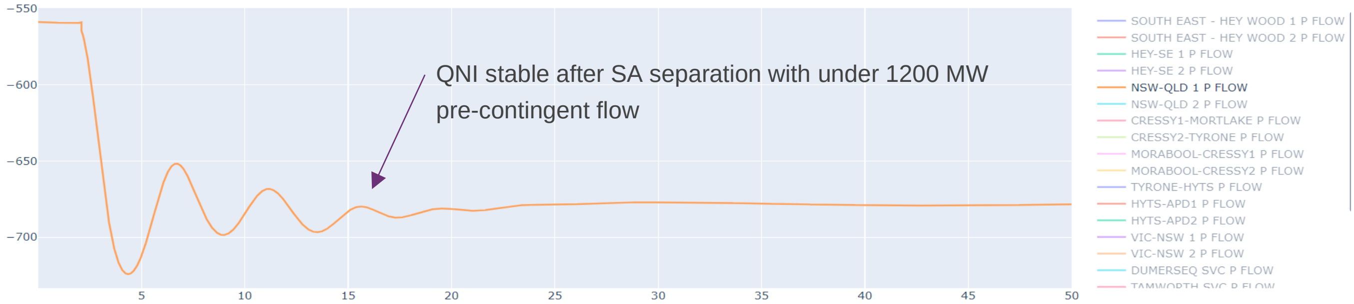


Figure 12 Simplified PSS®E model, QNI power flow, SA separation at HYTS, Export Case 11



In the full OPDMS model, QNI appeared to enter an unstable condition almost immediately after exceeding its export limit of 1,200 MW, at 1,400 MW. In the simplified model, however, QNI reached a peak flow of 1,460 MW with no instability and reached a settled point of 1,350 MW. QNI appeared to remain stable for this condition regardless of tuning.

A number of sensitivities were run to determine whether QNI could be pushed into an unstable condition in the simplified NEM model at varying levels of flow. It was found that with a pre-contingent flow of 1,400 MW (compared to 1,200 MW), QNI was pushed into an unstable condition following South Australia separation at HYTS after the flow swung to 1,600 MW. Therefore, it appears that, while it is possible to replicate QNI instability in the simplified NEM model, the maximum allowable power swing on QNI is higher compared to the full OPDMS model.

Figure 13 Simplified PSS®E model, QNI power flow with 1400 MW flow starting condition, SA separation at HYTS, Export Case 11

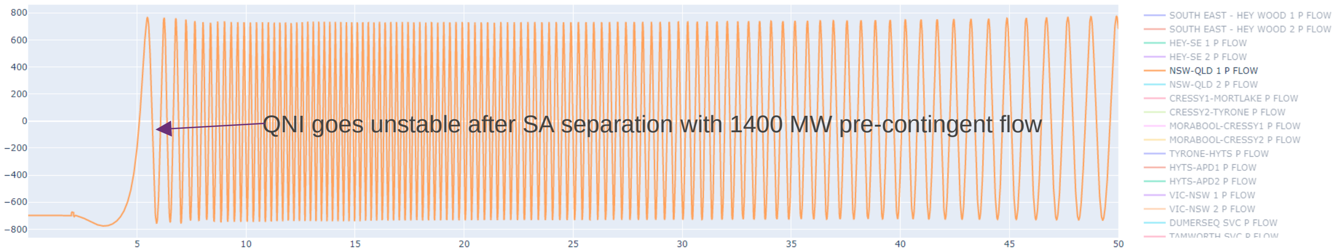


Table 14 Benchmarking results for 2022 PSFRR historical export Case 11, South Australia separation at Heywood

2022 PSFRR historical export Case 11, SA separation at HYTS			
Model	Pre-contingent QNI power flow (QLD export +ve) (MW)	Maximum QNI power flow swing (QLD export +ve) (MW)	Was the case stable? (Yes/No)
OPDMS full NEM model	1,200	1,400	No
Simplified NEM model	1,200	1,500	Yes
Simplified NEM model	1,400	1,600	No

South Australia, Queensland import cases

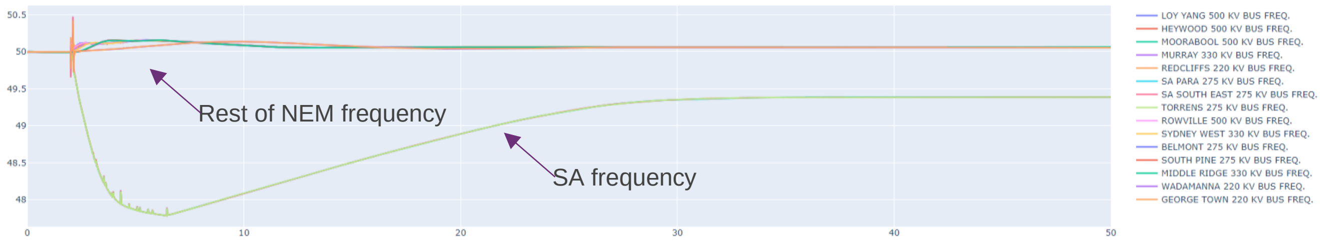
Import Case 1

Import Case 1 was benchmarked against the OPDMS full NEM power system model, with frequency performance in South Australia and the wider NEM the primary point of comparison. Of interest was:

- Load shedding triggered in South Australia as a result of the Heywood separation under South Australia import conditions.
- The frequency nadir reached in South Australia.
- Frequency recovery in South Australia.

Results from the OPDMS full NEM model can be seen in Figure 14.

Figure 14 OPDMS full NEM PSS®E model, SA frequency, SA separation at HYTS, Import Case 1

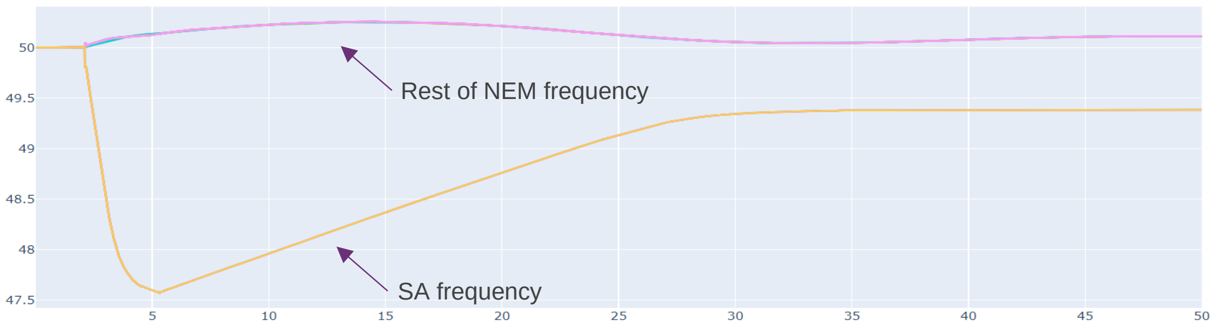


In the OPDMS full NEM model:

- Frequency in South Australia reached a nadir of 47.8 Hz after Heywood separation.
- 887 MW of underlying UFLS was triggered with 381 MW of DPV tripped incidentally by UFLS relays.
- An additional 10 MW of DPV was tripped by inverter settings.

Results from the tuned simplified model are shown in Figure 15.

Figure 15 Simplified PSS®E model, SA frequency, SA separation at HYTS, Import Case 1



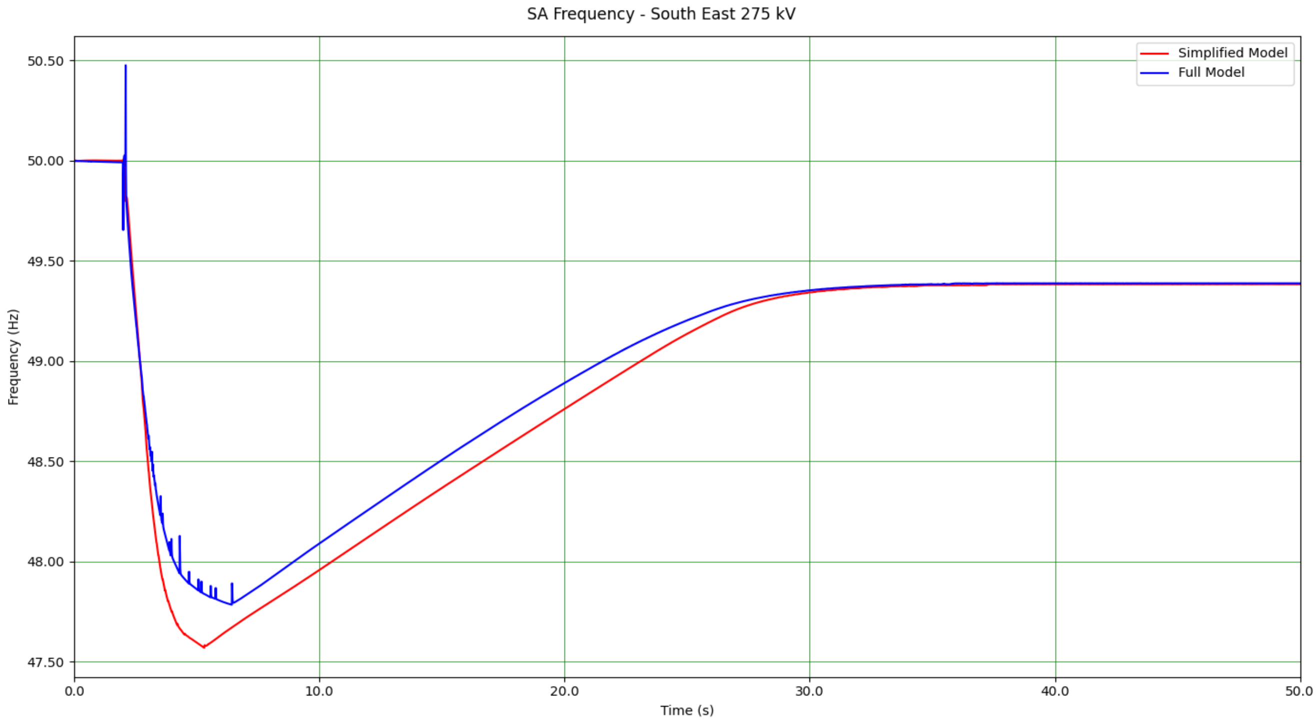
In the simplified model:

- Frequency in South Australia reached a nadir of 47.57 Hz after Heywood separation.
- 1,053 MW of underlying UFLS was triggered with 452 MW of DPV tripped incidentally by UFLS relays.
- An additional 17 MW of DPV was tripped by inverter settings.

Table 15 Benchmarking results for 2022 PSFRR historical Import Case 1, South Australia separation at Heywood

2022 PSFRR historical Import Case 1, SA separation at HYTS				
Model	**SA frequency nadir (Hz)**	**SA net UFLS tripped (MW)**	**DPV tripped on inverter settings only (MW)**	**Was the case stable? (Yes/No)**
OPDMS full NEM model	47.8	506	10	Yes
Simplified NEM model	47.6	601	17	Yes

Figure 16 Simplified PSS®E model and OPDMS full NEM PSS®E model, SA frequency, SA separation at HYTS, Import Case 1



The frequency decline triggered in South Australia in the simplified model as a result of the separation cannot be attributed to 7 MW of additional DPV tripping due to voltage protection. It appears as though frequency movements in South Australia are generally exaggerated in the simplified model compared to the OPDMS full NEM model. As synchronous regional inertia is identical in both models, a number of factors could be causing this, including:

- Differences in governor response due to simplified governors set to mandatory PFR requirements underestimating the true response of governors in South Australia.
- Asynchronous inertia such as that from wind turbines included in the OPDMS snapshot not being included in the simplified model of the South Australia region results in a higher RoCoF after a contingency event.

A4.2.2 Separation of South Australia at Moorabool Terminal Station (MLTS)

South Australia, Queensland export cases

Export Case 1

Export Case 1 was not stable following South Australia separation at MLTS in the OPDMS full NEM model. This condition was replicated in the simplified model, with instability detected immediately after separation. Voltage collapse was observed at each end of QNI across both models, which eventually manifested as voltage and frequency instability throughout the model. The simplified model therefore succeeded in replicating the instability observed in the full NEM model. This condition was replicated for the simplified model both with and without fault level tuning applied.

Figure 17 Simplified PSS®E model, SA separation at MLTS, Export Case 1

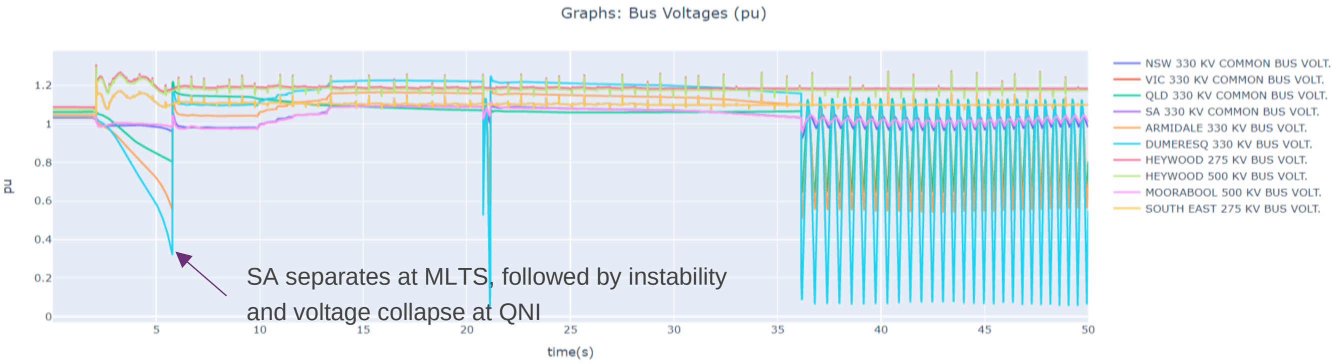


Figure 18 Full OPDMS PSS®E model, SA separation at MLTS, Export Case 1

Export Case 3

Similar to Export Case 1, the Export Case 3 was not stable after a separation event at MLTS in the OPDMS full NEM model. This condition was replicated in the simplified model, with instability detected immediately after separation. Voltage instabilities were observed at each end of QNI across both models. Therefore, the simplified model also produced instability, similar to what was observed in the main model. This condition was replicated for the simplified model with and without fault level tuning applied.

Figure 19 Simplified PSS®E model, SA separation at MLTS, Export Case 3

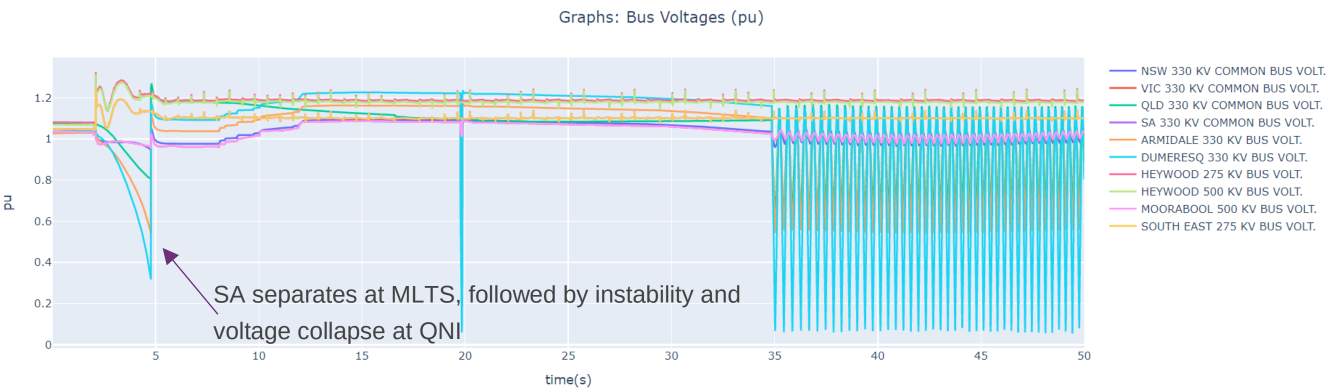
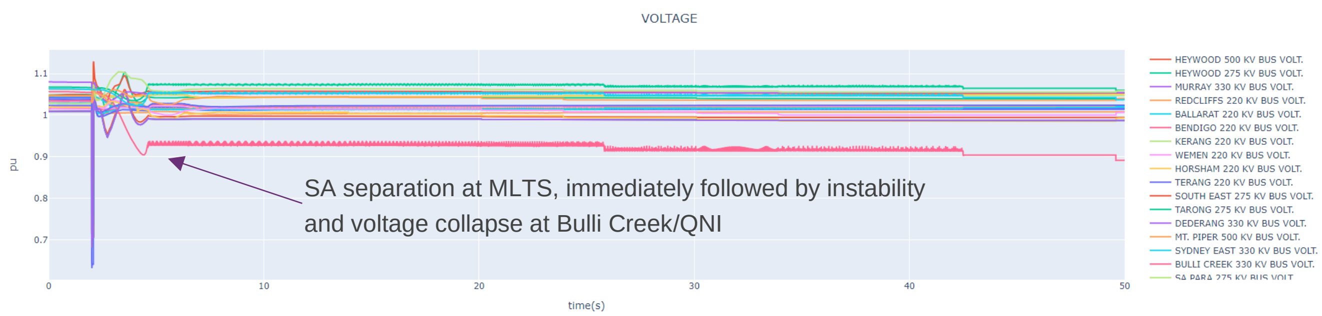


Figure 20 Full OPDMS PSS®E model, SA separation at MLTS, Export Case 3



South Australia, Queensland import cases

Import Case 1

Import Case 1 for the Moorabool separation contingency was stable in both the OPDMS full NEM model and the simplified model. In the OPDMS full NEM model:

- Frequency in South Australia reached a nadir of 47.8 Hz following separation.
- 887 MW of underlying UFLS was triggered with 381 MW of DPV tripped incidentally by UFLS relays.
- An additional 11 MW of DPV was tripped by inverter settings.
- The APD loads were tripped by EAPT almost immediately after separation.

In the simplified NEM model:

- Frequency in South Australia reached a nadir of 47.57 Hz following separation.

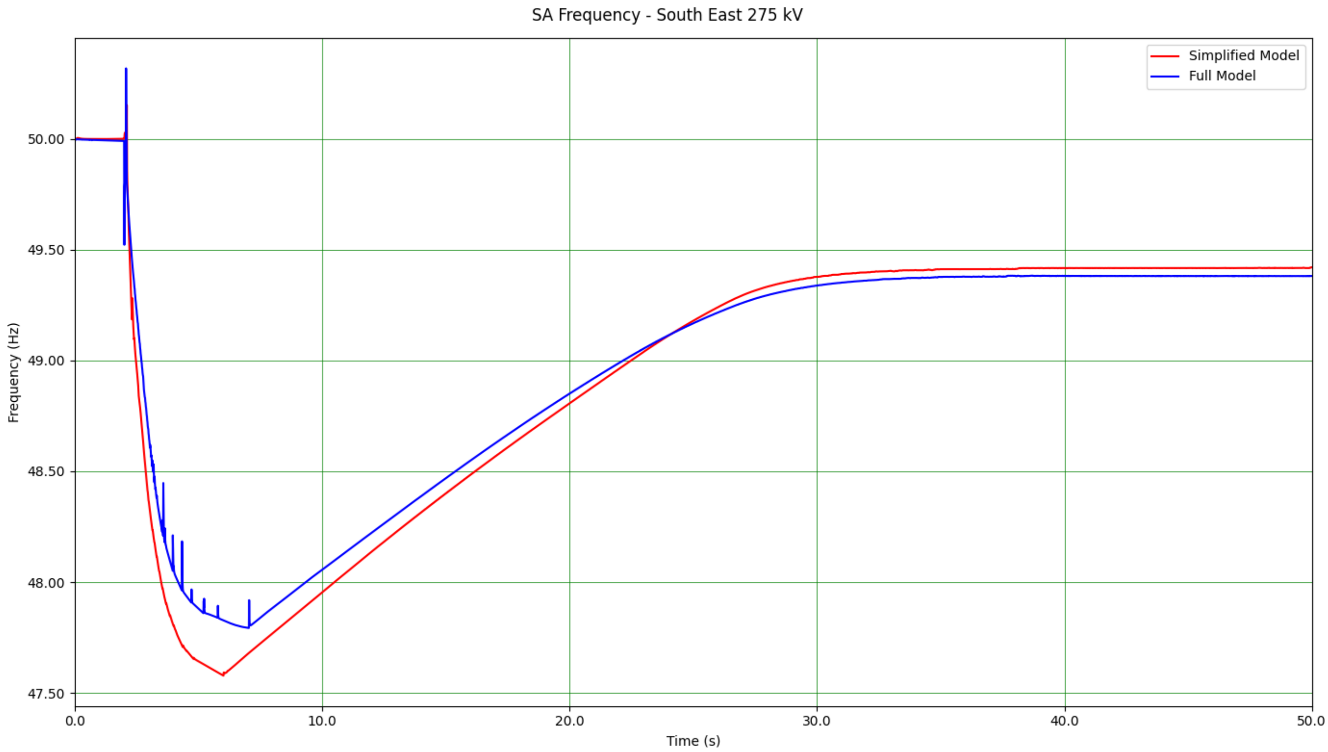
- 1,053 MW of underlying UFLS was triggered with 452 MW of DPV tripped incidentally by UFLS relays.
- An additional 11 MW of DPV was tripped by inverter settings.
- The APD loads were tripped by EAPT 0.3 s after separation.

Table 16 Benchmarking results for 2022 PSFRR historical Import Case 1, South Australia separation at Moorabool

2022 PSFRR historical Import Case 1, SA separation at MLTS				
Model	SA frequency nadir (Hz)	SA net UFLS tripped (MW)	DPV tripped on inverter settings only (MW)	Was the case stable? (Yes/No)
OPDMS full NEM model	47.8	506	11	Yes
Simplified NEM model	47.6	601	11	Yes

The simplified model showed a marginally greater frequency decline in Import Case 1 following South Australia separation at Moorabool than in the OPDMS full NEM model. This trend is consistent with the results from the other benchmarking studies, where frequency movements are more exaggerated in the simplified model rather than OPDMS.

Figure 21 Simplified PSS®E model and OPDMS full NEM PSS®E model, SA frequency, SA separation at MLTS, Import Case 1



A4.2.3 Loss of the Victoria – New South Wales Interconnector (VNI)

A single case was tested to check whether the loss of VNI replicated the instability observed in the OPDMS full NEM model. The simplified NEM model results did not show the same instability exhibited by the OPDMS full NEM model. The simplified model was able to separate into two stable islanded regions, with no obvious instability detected. The simplified model appears capable of dealing with a VNI separation with fewer negative interactions between generator controllers observed. For a VNI separation event, the simplified model appeared significantly less conservative compared to the OPDMS full NEM model.

Figure 22 OPDMS full NEM PSS®E model, VNI separation, Export Case 1

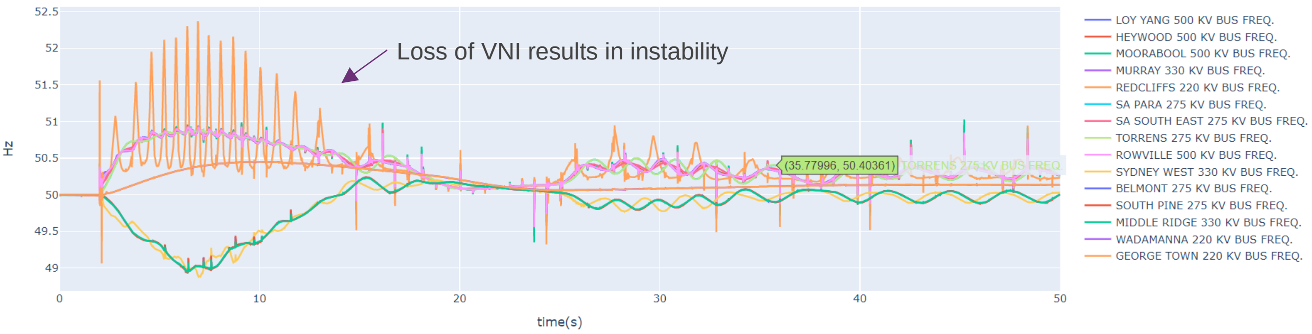
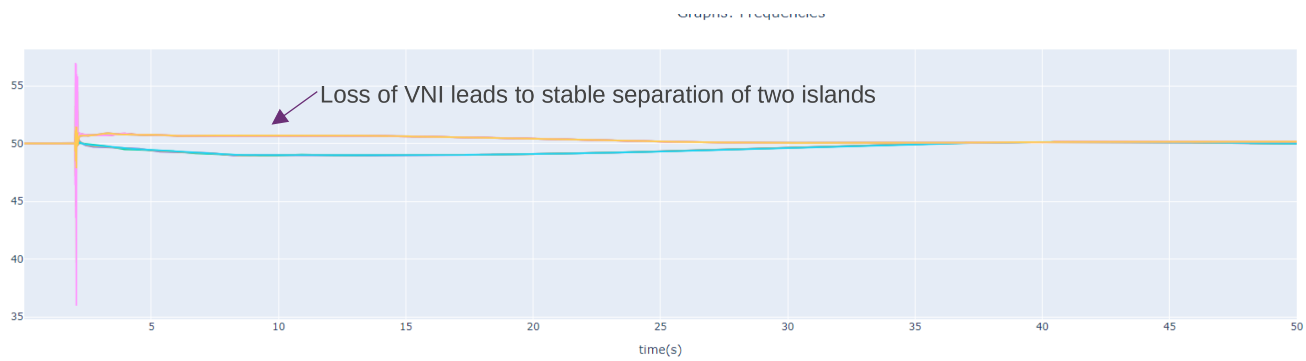


Figure 23 Simplified PSS®E model, VNI separation, Export Case 1



A4.2.4 Integration of Project EnergyConnect Stage 2

Major changes to the interconnector capacity connecting South Australia to the rest of the NEM will come with the commissioning of PEC, as shown in Table 17. It should be noted that the present Heywood interconnector limits are 550 MW South Australia export and 600 MW South Australia import, however increased Heywood interconnector transfer capacity post-PEC Stage 2 commissioning as projected by ElectraNet is considered in the study.

Table 17 South Australia AC interconnector capacities, post PEC commissioning

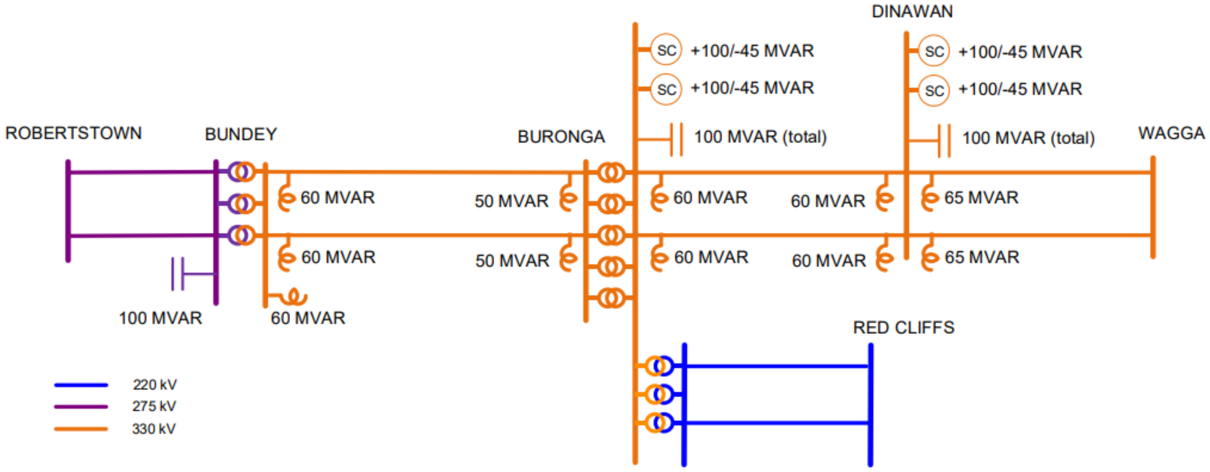
PEC Stage	In service date[A]/	HIC capacity (MW)	PEC capacity (MW)	Combined capacity (MW)
1	December 2023	600 SA Import 550 SA Export	150 SA Import 150 SA Export/	750 SA Import 700 SA Export
2[42]	December 2024	750 SA Import 750 SA Export/	800 SA Import 800 SA Export	1300 SA Import 1450 SA Export

A. This does not include time required for full capacity release via the NER 5.7.7 process.

The simplified single line diagram of PEC Stage 2 is shown in Figure 24 below.

[42] ElectraNet 2021 Transmission Annual Planning Report, p10, at https://www.electranet.com.au/wp-content/uploads/2021-ElectraNet Transmission-Annual-Planning-Report.pdf.

Figure 24 Project EnergyConnect Stage 2 singe line diagram



To enable studies with future operating conditions for FY 2027-28, PEC Stage 2 was integrated into the future simplified NEM model. The PEC Stage 2 model was integrated with the simplified model with connections between Robertstown and South Australia fault level buses established, and between Wagga Wagga and New South Wales fault level buses established, thereby allowing for power transfers between New South Wales and South Australia via the interconnector.

Flows on PEC are controlled primarily by five phase shifting transformers, which regulate active power flows via phase angle settings. During the setup of the future simplified model NEM cases, the phase angles of the PEC phase shifting transformers were adjusted iteratively to increase or decrease flows as required.

A4.3 Benchmarking with 2022 PSFRR future full NEM model studies

AEMO also completed benchmarking of specific contingency events assessed against results of the future studies completed for the 2022 PSFRR using a modified full NEM OPDMS model with PEC Stage 2 included. The simplified model cases were prepared as per the steps detailed in Appendix A4.2, with the addition of applying the correct PEC flow by adjusting the phase angles of the PEC phase shifting transformers.

The following contingencies, which were studied as part of the 2022 PSFRR, were used as part of the benchmarking of the simplified model with future operating conditions and PEC Stage 2 included:

- Separation of South Australia through loss of Heywood – South East 275 kV lines.
- Separation of South Australia at MLTS.

A4.3.1 South Australia, Queensland export cases

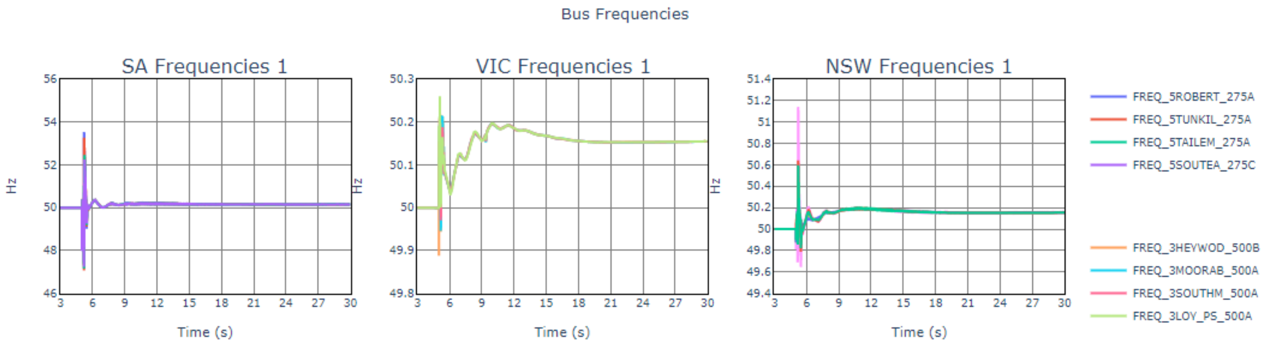
Export cases considering a trip of the Heywood Interconnector, and a trip of the connection between South Australia and Victoria at MLTS were run in PSS®E using a wide area NEM model with PEC integrated. Both cases considered the same extreme dispatch assumptions, with both PEC and the Heywood lines exporting at maximum capacity. Both of these cases were found to be unstable and did not solve past the fault being cleared. Therefore, the simplified model exhibited the same behaviour as the OPDMS full NEM model, with non-convergences almost immediately following the fault being cleared.

A4.3.2 South Australia, Queensland import cases

Separation of South Australia through loss of Heywood – South East 275 kV lines

The South Australia import HYTS contingency case solved in the OPDMS full NEM PSS®E model. With PEC integrated into the power system, the Heywood contingency with a flow of 600 MW importing into South Australia, did not result in the immediate disconnection of South Australia from the wider NEM, and therefore the resulting disturbance from the contingency remained relatively limited.

Figure 25 OPDMS full NEM PSS®E model, regional frequency, SA separation at HYTS



System instability in this case was avoided by the function of the SPS. The design of this scheme is not final, but in the 2022 PSFRR full NEM future case benchmarking studies, the scheme was implemented as follows for South Australia import conditions:

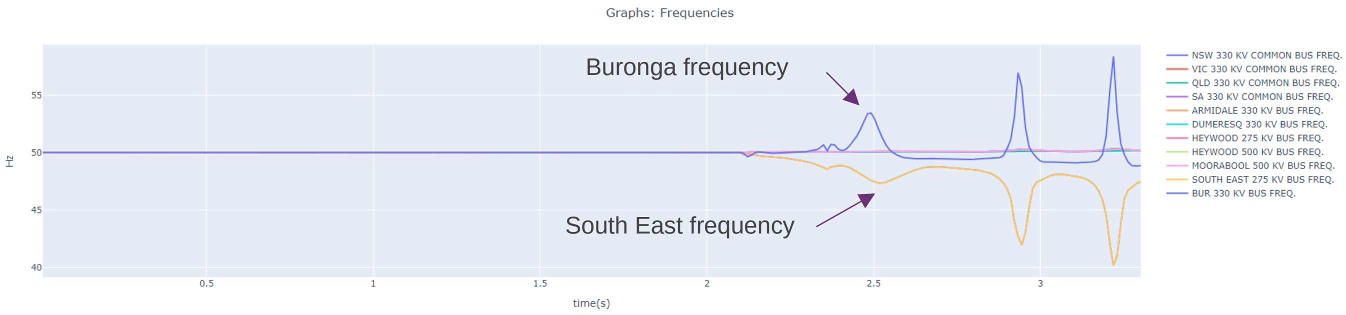
- Tripped 400 MW of load in South Australia.
- Injected active power from the Hornsdale BESS (60 MW).
- Injected active power from the Torrens Island Power Station (TIPS) BESS (50 MW modelled as a negative load switched into service).

The functioning of this scheme 250 ms after the fault clearance prevented a surge in power flow on PEC and allowed the NEM to remain stable following the contingency.

For the simplified model with PEC integrated, the same SPS was implemented. However, with identical conditions and SPS actions following fault clearance applied, the simplified model case was found to be unstable, with non-convergence of the simulation almost immediately following the contingency reported (1.5 s after fault clearance).

Analysis of the results obtained before model non-convergence showed that the frequency at Buronga and South East busbars appears to have diverged significantly from the wider NEM, suggesting that South Australia and PEC effectively lost synchronism from the wider NEM despite an electrical connection remaining in place, as seen in Figure 26.

Figure 26 Simplified PSS®E model, regional frequency, SA separation at HYTS

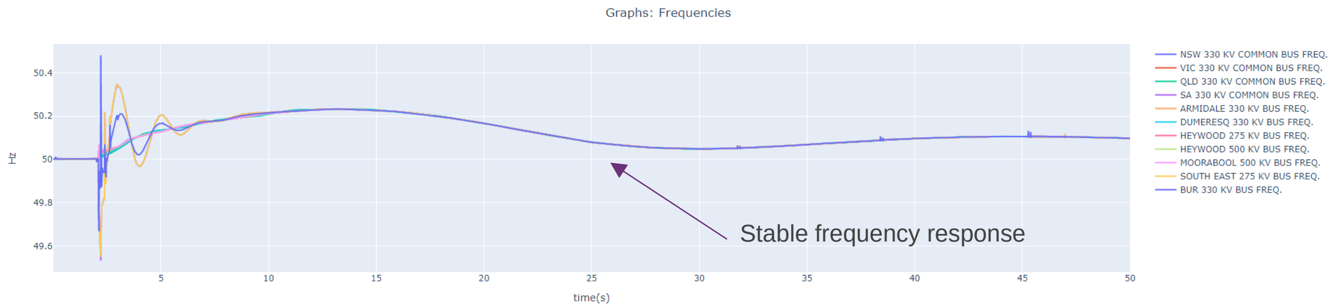


Also observed in the case before non-convergence was a voltage collapse followed by significant voltage and active power swings on PEC. It was found that the simplified model case was stable if the following changes were applied:

- SPS delay reduced to 100 ms after fault clearance.
- Fault level benchmarking to reduce the voltage relationship between PEC and Heywood in South Australia.
- Increased load disconnected from the SPS scheme to 610 MW.

Under these conditions, it was possible to observe a stable response from the model without collapse following the contingency, as seen in Figure 27. Therefore, the simplified model with PEC Stage 2 included appears to be less resilient than the wide area model for the interconnector tripping events studied – the model was only able to establish convergence when protection schemes were made more aggressive.

Figure 27 Simplified PSS®E model, regional frequency, SA separation at HYTS, successful sensitivity case

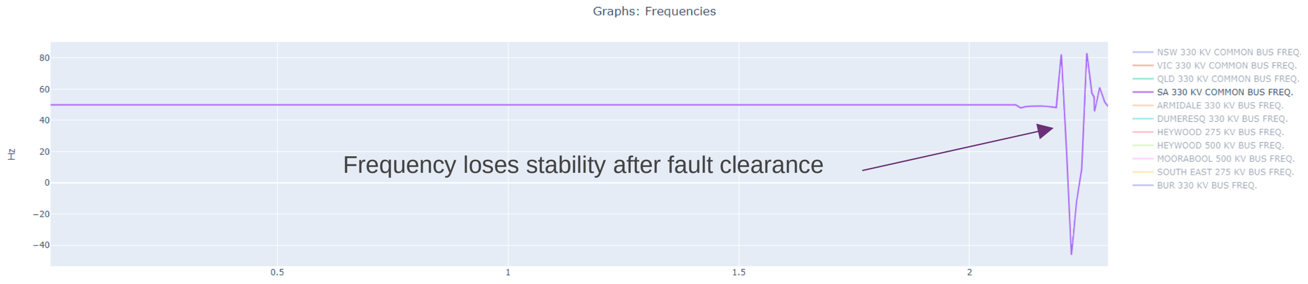


Separation of South Australia at Moorabool Terminal Station (MLTS)

Similar to the HYTS contingency, the MLTS contingency produced a stable outcome in the OPDMS full NEM model. Following the contingency, both the SPS and the EAPT scheme were activated, with EAPT tripping ~462 MW of load at Moorabool, and the SPS tripping a further 400 MW of load as well as a 60 MW response from Hornsdale BESS, and 50 MW from the TIPS BESS.

However, a stable condition following this contingency could not be replicated in the simplified model, which showed signs of instability immediately following fault clearance, as shown in Figure 28. Sensitivities were completed decreasing the delay of the SPS and increasing the amount of load tripped by the SPS, but the case remained unstable. The contingency severity appeared to limit the ability of the model to produce a valid solution.

Figure 28 Simplified PSS®E model, SA frequency, SA separation at MLTS, frequency loses stability almost immediately following fault clearance



A4.4 Conclusions

- It is important to note that these studies would have ideally been completed with the OPDMS full NEM model. However, it was determined that preparing 12 dispatches using the full model would not be practically possible as part of the GPSRR due to the time that this would require.
  - Importantly, the use of a simplified NEM model enabled the assessment of a wider range of future dispatch scenarios and contingencies, with the full NEM model used to benchmark the simplified model.
  - This highlights the difficulties associated with undertaking detailed studies for future operating conditions for future timeframes that include large numbers of anticipated network augmentations and generation for which dynamic models are not readily available.
- Even though the simplified network can capture frequency variations with reasonable accuracy, it is impacted by the following limitations:
  - The model excludes actual network impedances, meaning it will not accurately predict power system voltages.
  - The model is an approximation of fault ride-through characteristics of IBR plant.
  - The model is an approximation of the voltage-based tripping behaviour of DPV.
- For the majority of cases, the simplified model loses stability for the same contingency events which cause instability in the full NEM OPDMS model.
- Since the simplified model cannot accurately predict system voltages, only high impedance faults should be applied to avoid the spurious tripping of DPV. Therefore, the simplified model cannot accurately capture DPV shake off due to large voltage disturbances. However, the model does allow for a specified amount/percentage of regional DPV generation to be tripped as part of contingency to study the resultant impact on system frequency.
- For historical cases without PEC Stage 2 included, an interconnector contingency event that causes South Australia separation from the NEM is generally more likely to reach a lower South Australian frequency nadir in the simplified model than compared to the full NEM model.
- Protection schemes including UFLS, OFGS and specific interconnector protection schemes were successfully integrated into the simplified model, however, slight changes in operating times due to slight differences in frequency or voltage step changes can make a significant difference to results obtained between models.

- The simplified model can simulate an unstable QNI condition as a result of increased flows due to a contingency such as the loss of the Heywood interconnector. However, the power swings on interconnectors and their angular stability predictions may be less conservative when compared with the full NEM OPDMS model. It is possible that this could be due to different reactive power flows on the line.
- The simplified model without PEC Stage 2 included appears to be less conservative in terms of its ability to form two stable islands following the loss of VNI. It is unclear whether the instability simulated in the full NEM OPDMS model is more representative of actual power system performance without operational data, however the discrepancy when dealing with these events should be considered when interpreting results obtain from studies using the simplified model.
- The simplified model with PEC Stage 2 included appears to be less resilient than the wide area model for the interconnector tripping events studied. The model was only able to establish convergence when protection schemes were made more aggressive.
- Fault level benchmarking is necessary to prevent voltage changes on the Heywood interconnector causing a similar disturbance on PEC. The two interconnectors should be decoupled by some non-zero impedance before performing contingency analysis. Therefore, fault level benchmarking was completed for all future cases studied for the 2023 GPSRR.
- It was observed that the simplified model can capture QNI instability but cannot necessarily predict the exact QNI flow threshold at which instability occurs for a given contingency. This is consistent with what was observed in the 2022 PSFRR. As detailed in Section 4 and 5, the purpose of the 2023 GPSRR future studies was to investigate what non-credible contingencies across the NEM could lead to QNI instability, rather than to estimate the threshold at which QNI loses stability. Therefore, it was determined that the simplified model was suitable to use for the 2023 GPSRR future studies.
- Overall, it was determined that the simplified model is useful for screening studies to evaluate potential power system risks. The approach offers several advantages compared to the use of single or multi-mass models.

A5. Simulation results for historical studies

This section gives detailed references to study cases, results, and key result graphs for the Wagga, Tamworth and Mount Piper contingencies to supplement the key findings provided in Section 5.

A5.1 Risk 1: Wagga contingency

A5.1.1 Study results

The key results of the loss of line 62: 330 kV Wagga – Jindera and line 63: 330 kV Wagga – Darlington Point simulation studies are given Table 18.

Table 18 Case results for the Wagga contingency

Case	NSW/NEM frequency nadir/peak (Hz)	NSW + VIC total DPV tripped on DPV inverter settings only (MW)^	Total inter-tripped IBR generation (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
1	49.8	21 (1%)	580	None	Yes
2	49.8	118 (3%)	375	None	Yes*
3	50.0	0 (NA)	18	None	Yes*
4	49.3	182 (4%)	710	EAPT operated, SA freq peak = 51.01 Hz and SA OFGS tripped = 28.4 MW	No
5	49.9	103 (3%)	327	None	Yes
6	50.0	0 (NA)	18	None	Yes*
7	49.7	204 (4%)	735	None	Yes*
8	49.9	0 (NA)	185	None	Yes
9	49.8	185 (7%)	604	None	Yes*
10	49.7	122 (3%)	750	None	Yes*
11	49.5	157 (4%)	865	EAPT operated, SA freq peak = 51.01 Hz and SA OFGS tripped = 10.8 MW	No
12	49.7	221 (4%)	606	None	Yes*
13	49.9	59 (2%)	373	None	Yes
14	N/A	50 (2%)	480	QNI lost stability, QLD angular separation from NEM	No
15	50.0	58 (4%)	194	None	Yes*

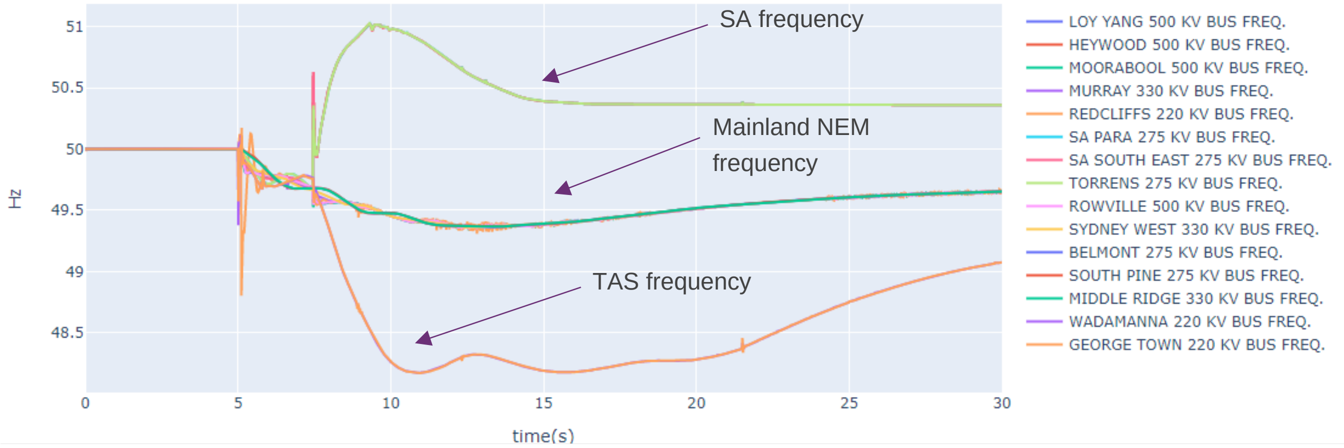
* Pass according to acceptance criteria but observations/modelling issues were recorded.
^ Percentage of total online NSW and VIC regional DPV generation tripped on inverter settings.

A5.1.2 Representative PSS®E results

Case 4 – 17/04/2022 1200 hrs

The simulation results for Case 4 for the Wagga contingency are shown in the figures below. Following fault clearance, the EAPT scheme (in mode 3) operated, separating South Australia from the rest of the NEM. As the frequency drops significantly in Tasmania, load shedding also occurs as part of the Adaptive Under Frequency Load Shedding 2 (AUFLS2)[43] scheme.

Figure 29 Case 4, Wagga contingency: system frequency traces



Case 14 – 29/08/2021 1030 hrs

The simulation results for Case 14 for the Wagga contingency are shown in the figures below. Case 14 crashed 5.5 s following fault clearance. As shown in the graph of system angles below, the Queensland system angle starts to separate from the rest of the NEM and the QNI distance protection operated for zone 1 at 5.46 s (however, the case crashed before the protection tripped the lines). This is considered the likely reason for the numerical instability in the case.

[43] The AUFLS scheme is a normally enabled control scheme designed to reduce the Fast Raise FCAS requirement in the Tasmania region by shedding contracted load when frequency in Tasmania falls below 48.8 Hz. The scheme continually monitors the system frequency, and if the frequency falls below 48.8 Hz up to four blocks of contracted industrial load will be tripped within 150 ms. The amount of load tripped is dependent on the RoCoF and the system inertia.

Figure 30 Case 14, Wagga contingency: system angles

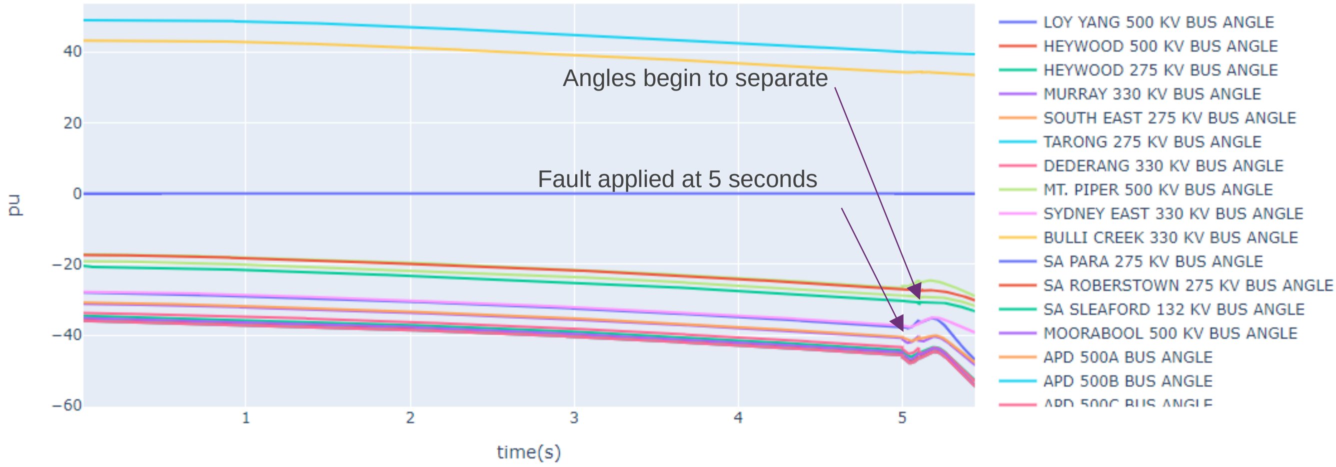


Figure 31 Case 14, Wagga contingency: QNI active power flow

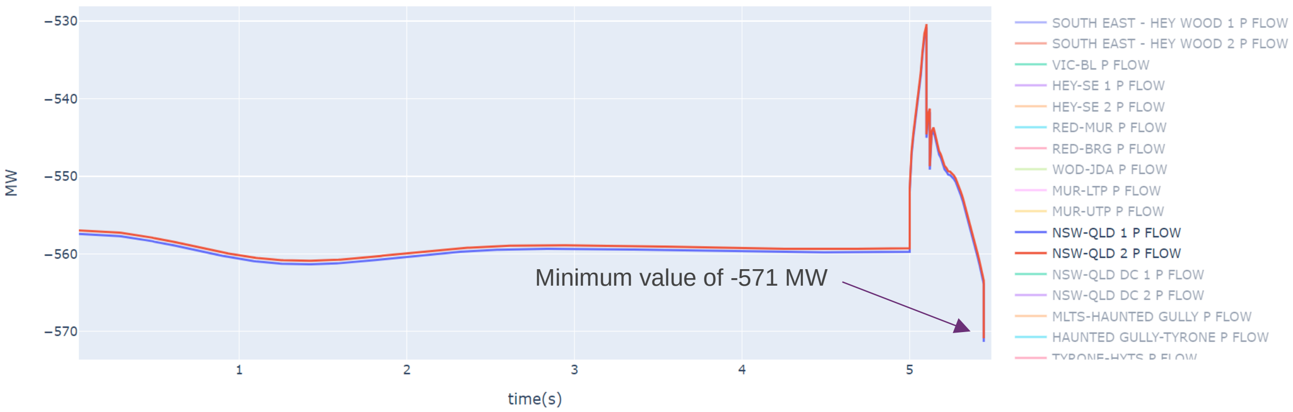


Figure 32 Case 14, Wagga contingency: generator active power outputs

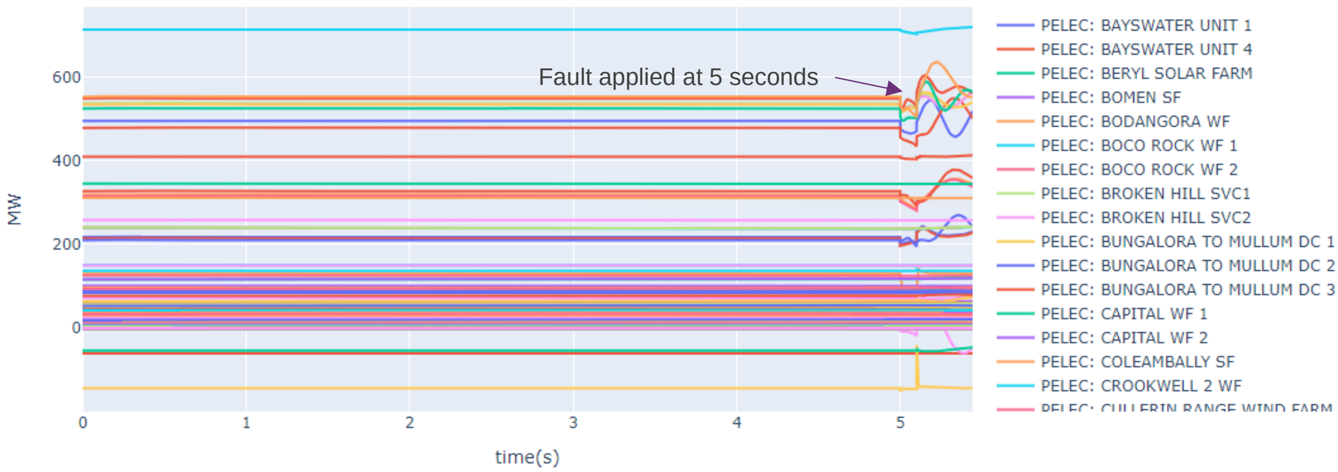


Figure 33 Case 14, Wagga contingency: system frequency traces

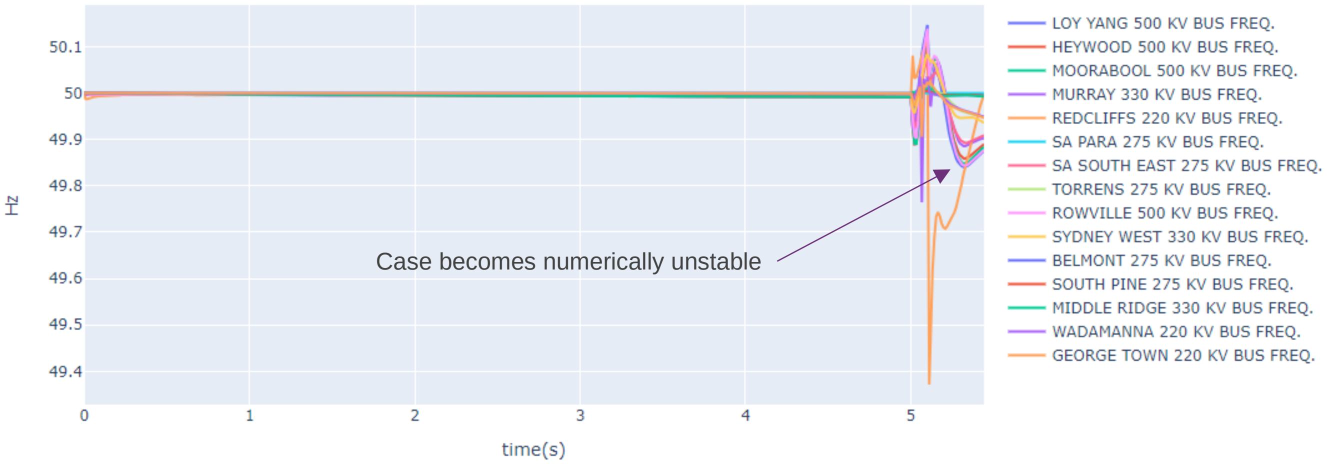
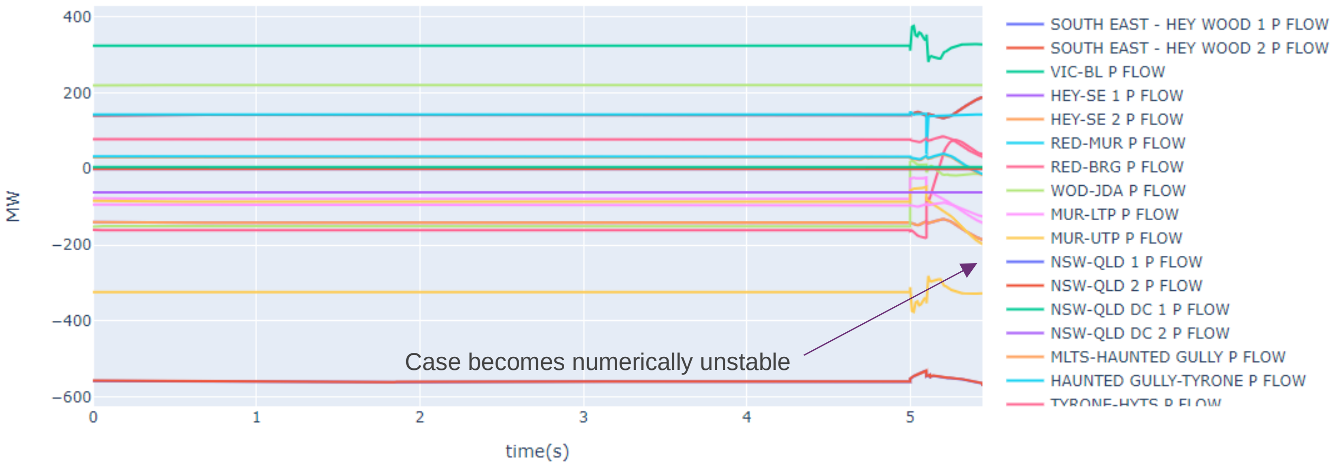


Figure 34 Case 14, Wagga contingency: line active power flows



Case 14 was rerun with approximately 300 MW less generation being inter-tripped by the relevant control schemes, and the case completes without Queensland separating from the rest of the NEM – see plot of system angles below. The simulation results are shown in the figures below.

Figure 35 Case 14, Wagga contingency, not inter-tripping Sunraysia SF and Limondale 1 SF: system angles

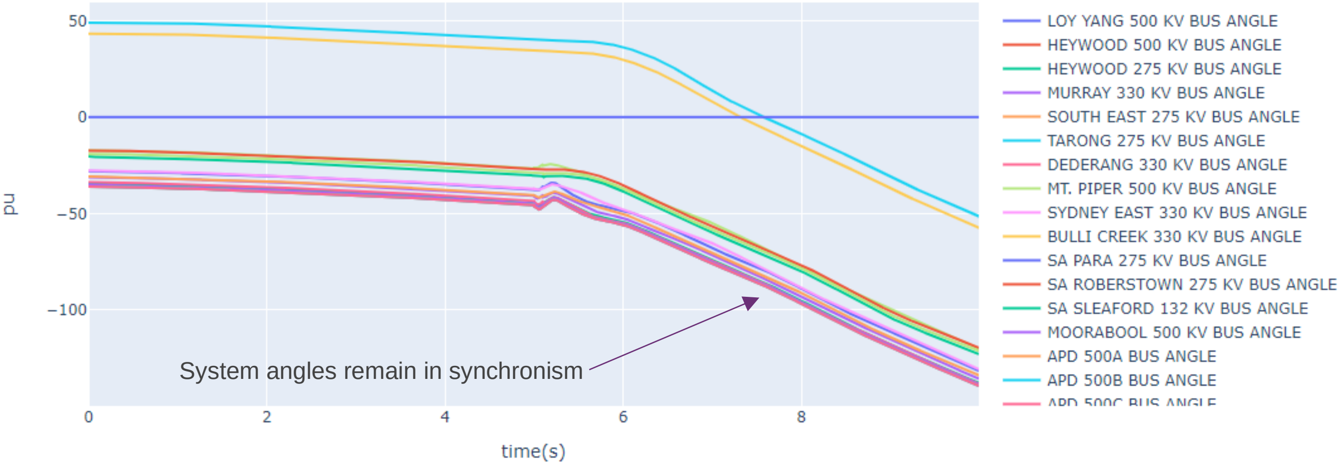


Figure 36 Case 14, Wagga contingency, not inter-tripping Sunraysia SF and Limondale 1 SF: QNI active power flow

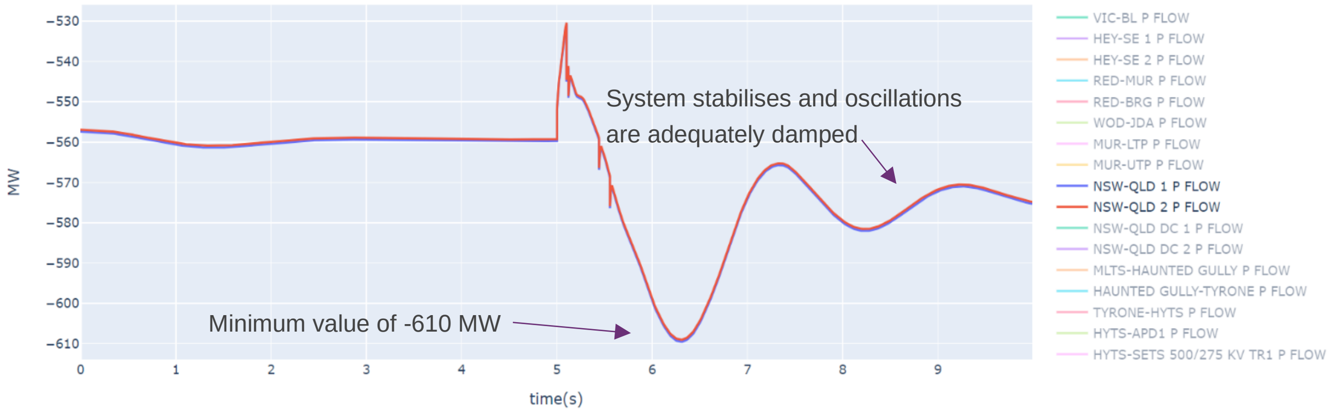


Figure 37 Case 14, Wagga contingency, not inter-tripping Sunraysia SF and Limondale 1 SF: generator active power outputs

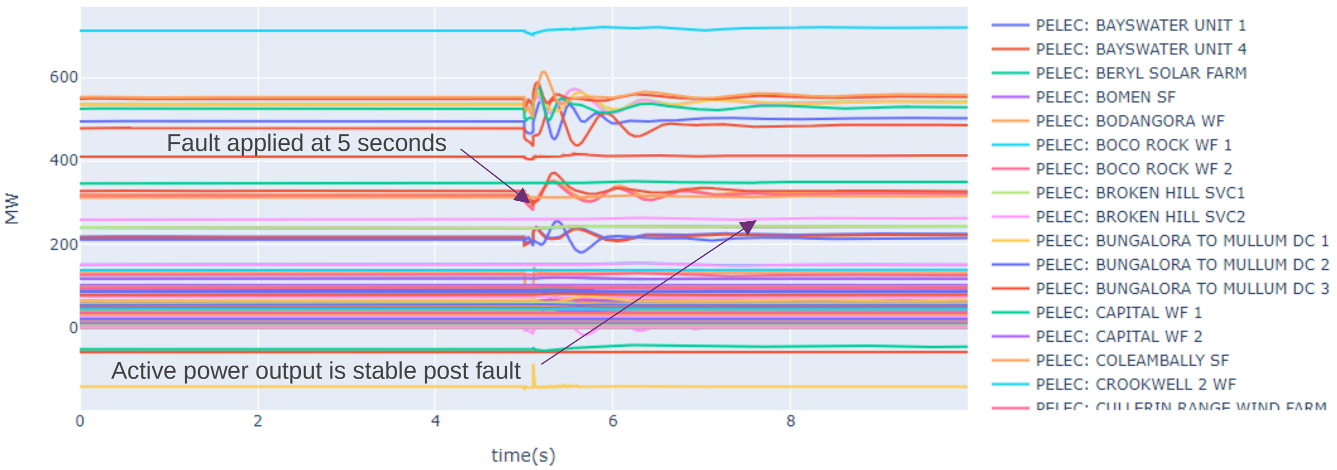


Figure 38 Case 14, Wagga contingency, not inter-tripping Sunraysia SF and Limondale 1 SF: system frequency traces

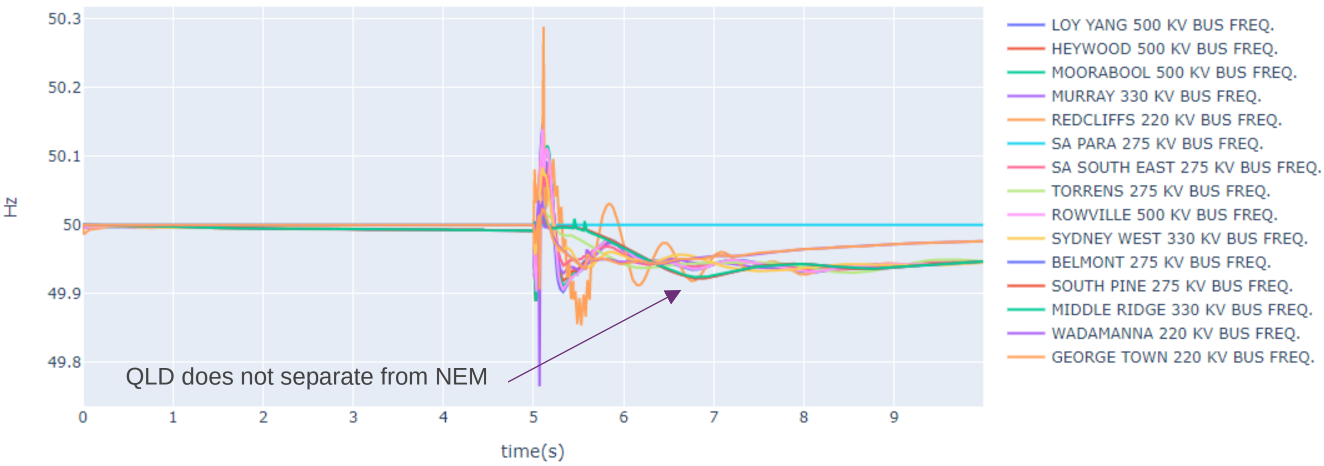
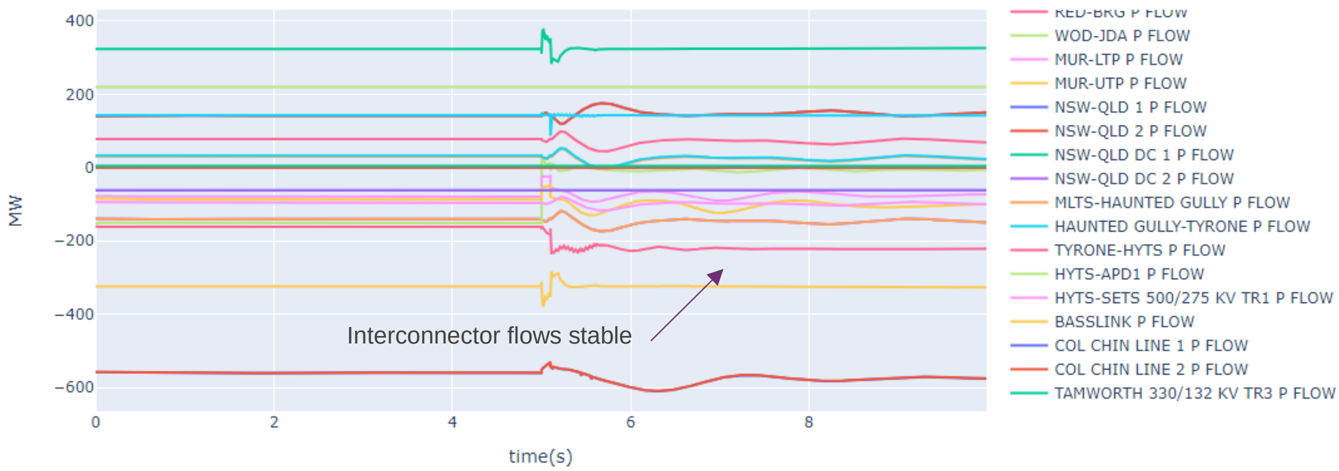


Figure 39 Case 14, Wagga contingency, not inter-tripping Sunraysia SF and Limondale 1 SF: line active power flows



A5.1.3 Representative PSCAD™ results

Case 4 – 17/04/2022 1100 hrs – PSCAD™ Results

The PSCAD™ simulation results for Case 4 for the Wagga contingency are shown in the figures below. This case has minimum synchronous generators dispatched but does not display any issues with fault ride-through of the inverter-based generation in New South Wales. This was indicative of all cases studied. No issues were observed with system voltages or IBR.

Figure 40 Case 4, Wagga contingency, PSCAD™ results: NSW solar farm active power outputs

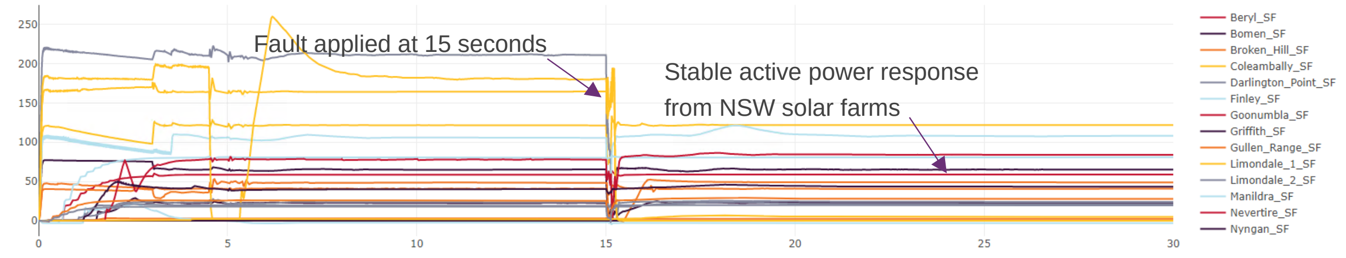


Figure 41 Case 4, Wagga contingency, PSCAD™ results: NSW solar farm reactive power outputs

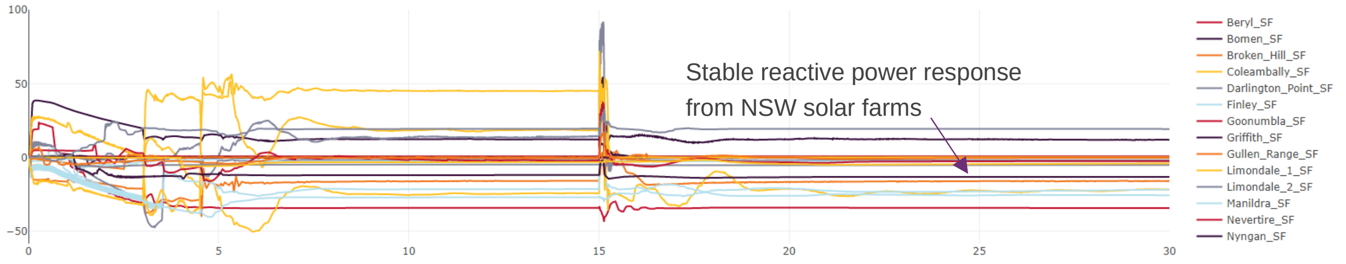


Figure 42 Case 4, Wagga contingency, PSCAD™ results: NSW wind farm active power outputs

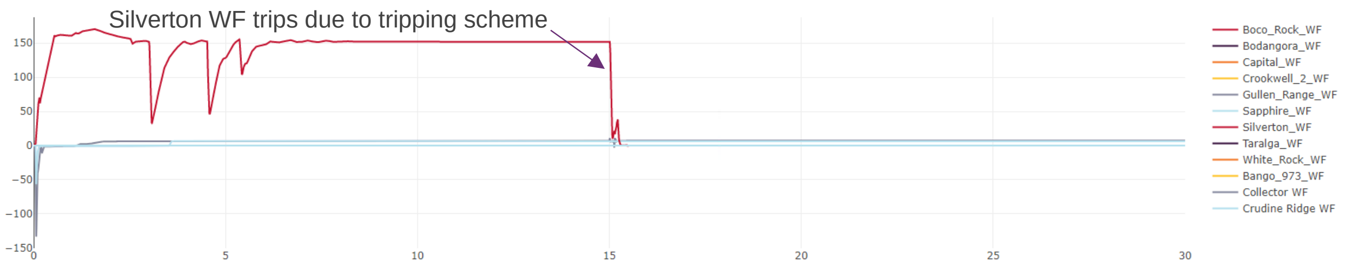
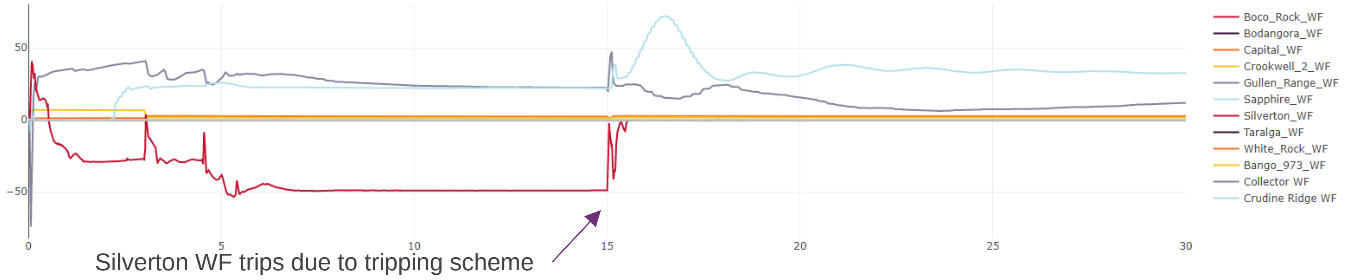


Figure 43 Case 4, Wagga contingency, PSCAD™ results: NSW wind farm reactive power outputs



A5.2 Risk 2: Tamworth contingency

A5.2.1 Study results

The key results of the Tamworth double 330 kV bus trip (Sections 1 and 3) due to CB failure of bus coupler CB 5102 simulation studies are given Table 19.

Table 19 Case results for the Tamworth contingency

Case	NSW/NEM frequency nadir/peak (Hz)	QLD frequency nadir/peak (Hz)	NSW total DPV tripped on DPV inverter settings only (MW)	QLD total DPV tripped on DPV inverter settings only (MW)	SPS, EFCS, control scheme operation	QNI stable (Yes/No)	Was the case stable? (Yes/No)
1	50.2	49.3	92 (13%)	9 (1%)	None	No, QNI flow = 160 MW import into QLD	No
2	49.4	50.3	388 (12%)	0 (0%)	EAPT operated, SA freq peak = 50.4 Hz	No, QNI flow = 386 MW export from QLD	No
3	50.0	50.0	0 (0%)	0 (NA)	None	Yes	Yes
4	49.9	49.9	157 (6%)	0 (0%)	None	Yes	Yes
5	49.8	50.3	75 (3%)	0 (0%)	None	Yes	Yes
6	49.7	50.9	0 (0%)	0 (NA)	None	No, QNI flow = 1,162 MW export from QLD	No
7	49.9	49.9	162 (5%)	0 (0%)	None	Yes	Yes
8	50.2	49.3	0 (0%)	0 (NA)	None	No, QNI flow = 538 MW import into QLD	No
9	50.1	50.1	87 (4%)	0 (0%)	None	Yes	Yes
10	49.9	50.1	161 (9%)	0 (0%)	None	Yes	Yes
11	50.1	49.6	170 (9%)	0 (0%)	None	No, QNI flow = 250 MW import into QLD	No
12	49.9	50.0	223 (7%)	0 (0%)	None	Yes	Yes
13	49.5	50.8	324 (14%)	116 (5%)	EAPT operated, SA freq nadir = 49.7 Hz	No, QNI flow = 750 MW export from QLD	No
14	N/A	N/A	136 (10%)	0 (0%)	None	No, QNI flow = 1,160 MW export from QLD	No
15	49.6	50.8	66 (6%)	63 (5%)	None	No, QNI flow = 950 MW export from QLD	No

Please note that in Case 5, the 132 kV lines between Moree and Inverell and Port Macquarie and Herons Creek tee are out of service, meaning that this contingency results in Queensland separating from the rest of the NEM at Tamworth.

The key results of the historical sensitivity case simulation studies are given in 0.

Table 20 Sensitivity case results for the Tamworth contingency

Case	132 kV tripping time (s) (Kempsey – Taree 180 degrees exceeded)	NSW/NEM frequency nadir/peak (Hz)	QLD frequency nadir/peak (Hz)	Was the case stable? (Yes/No)
1	5.95	49.6	50.8	Yes
2	6.62	NSW/VIC: 49.4 SA: 50.5	50.4	No, EAPT operates at 7s to separate SA, case crashes at 8 s
6	6.28	NSW/VIC: 49.5 SA: 50.5	50.9	Yes, EAPT operates at 8.9 s to separate SA
8	6.67	50.2	49.5	Yes
11	9.17	50.05	49.7	Yes
13	5.76	NSW/VIC: 49.4 SA: 49.6	50.8	Yes, EAPT operates at 6.4 s to separate SA
15	5.95	49.6	50.8	Yes

A5.2.2 Representative results

Case 2 – 17/10/2021 1300 hrs

The simulation results for Case 2 for the Tamworth contingency are shown in the figures below. Case 2 crashed after 8.0 s following fault clearance. The Queensland system angle separated from the rest of the NEM and the QNI distance protection operated for zone 1 at 7.97 s (however, the case crashed before the protection tripped the lines). The EAPT scheme (in mode 3) was found to operate to island South Australia at 7.3 s due to the summated active power flow to South Australia through the Heywood transformers dropping below the threshold of 20 MW for more than 2 s and the Heywood – South East 275 kV line frequency dropping below 49.7 Hz for more than 100 ms.

Figure 44 Case 2, Tamworth contingency: system angles

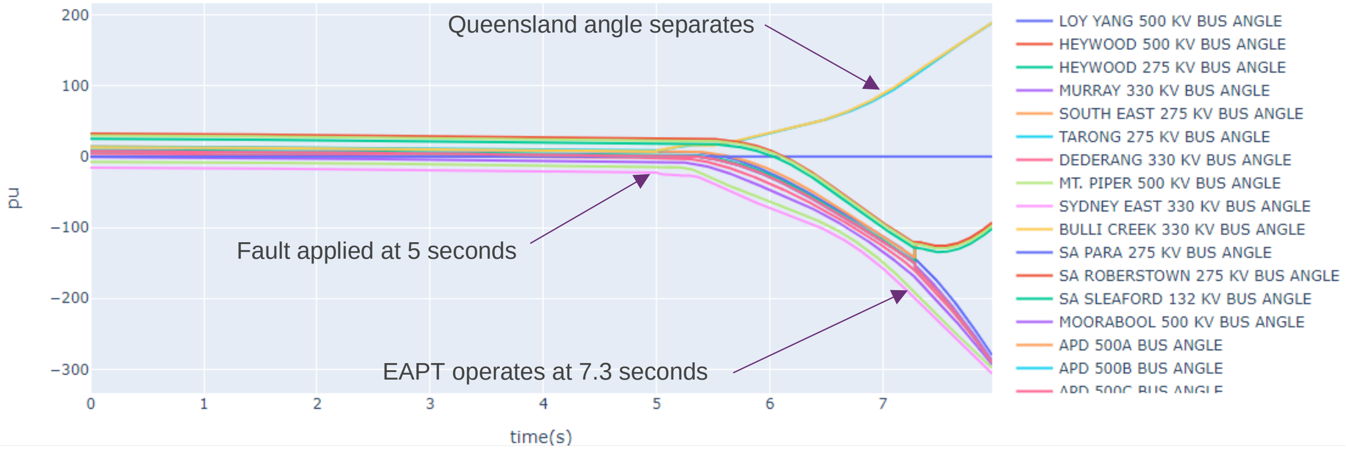


Figure 45 Case 2, Tamworth contingency: generator active power outputs

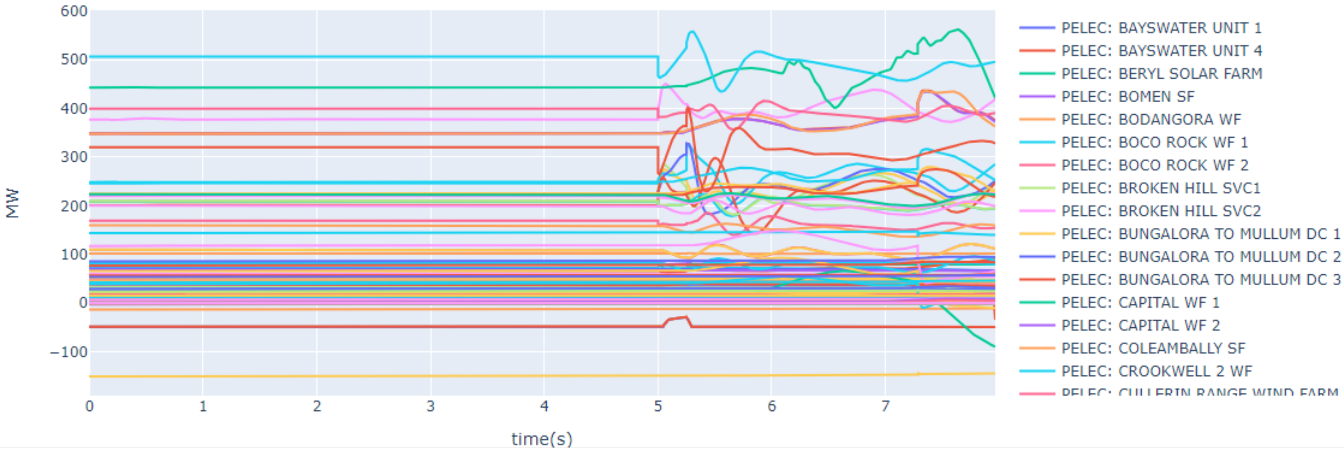


Figure 46 Case 2, Tamworth contingency: system frequency traces

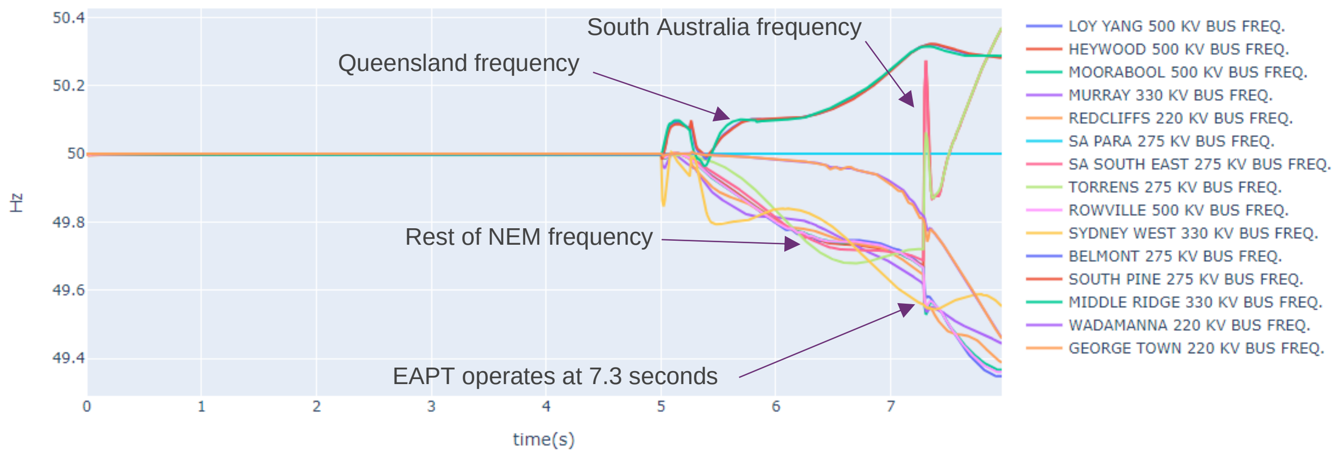
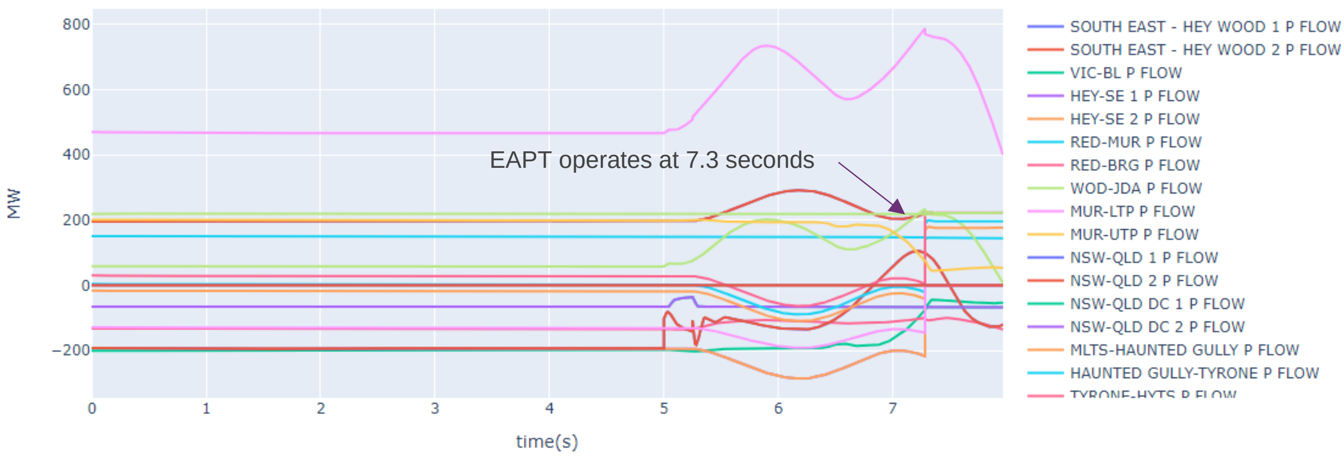


Figure 47 Case 2, Tamworth contingency: line active power flows



Case 8 – 19/01/2022 2030 hrs

The simulation results for Case 8 for the Tamworth contingency are shown in the figures below. QNI lost stability and the Queensland system angle separated from the rest of the NEM following fault clearance, but the QNI distance protection did not operate to separate Queensland due to the current falling below the threshold. Hence, sustained, undamped power swings on QNI were observed.

Figure 48 Case 8, Tamworth contingency: generator active power outputs

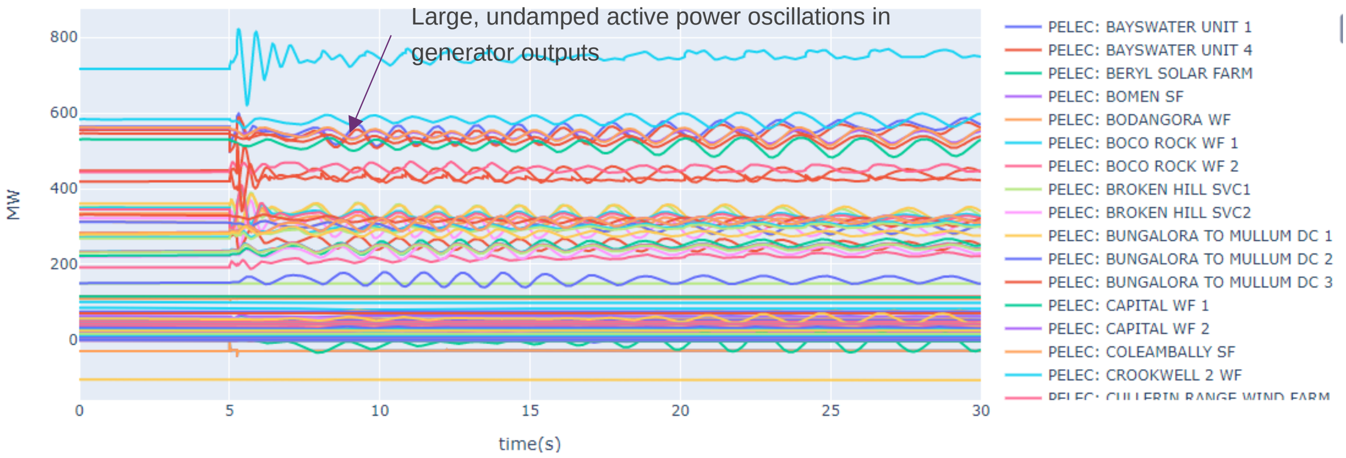


Figure 49 Case 8, Tamworth contingency: system frequency traces

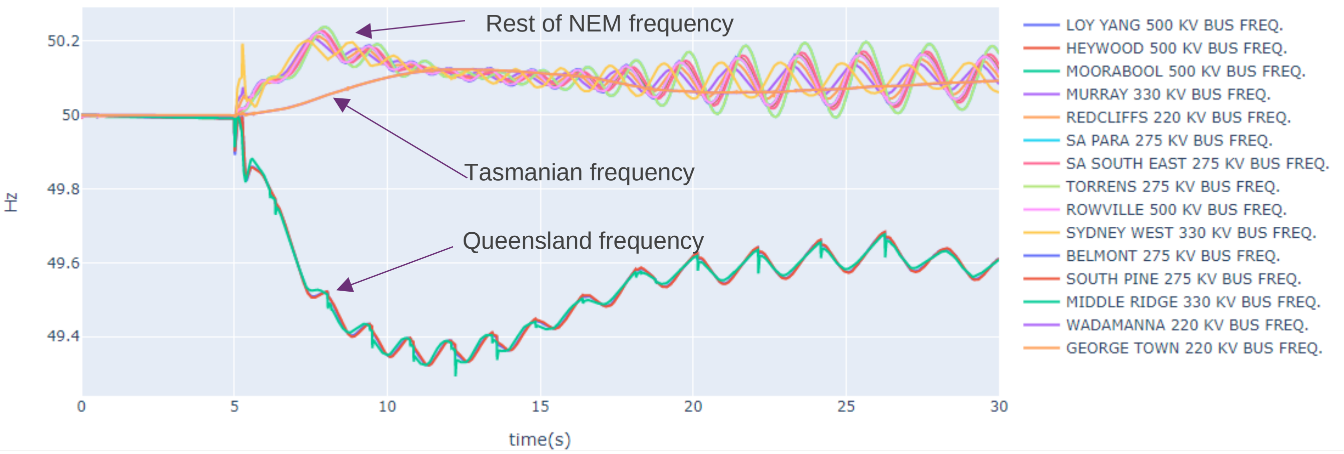
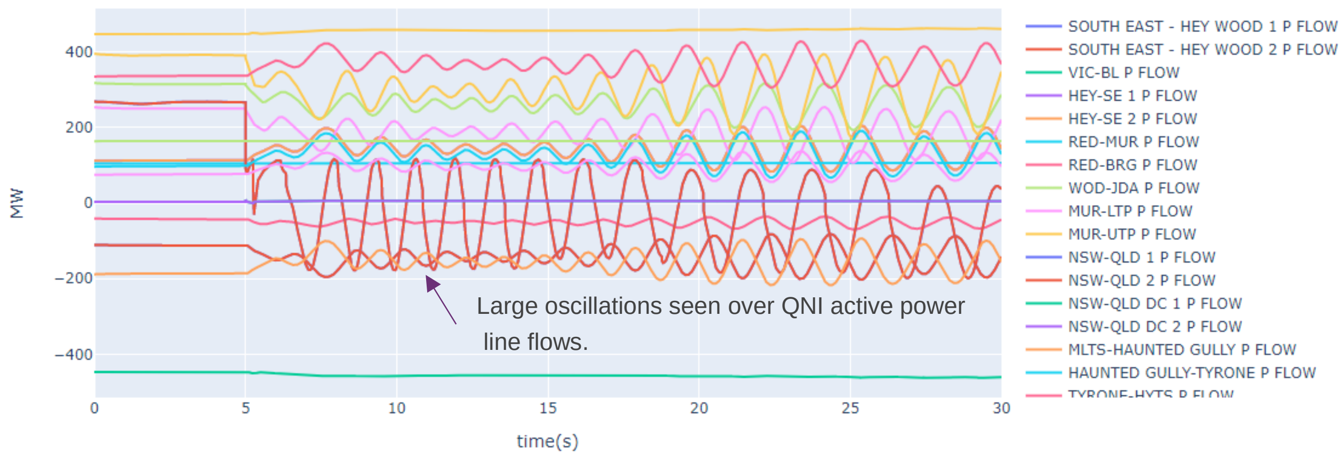


Figure 50 Case 8, Tamworth contingency: line active power flows



Case 8 was rerun tripping the 132 kV lines between Kempsey and Taree, and Moree and Inverell. The simulation results are shown in the figures below. Queensland successfully separated from the rest of the NEM and Queensland frequency did not fall below 49 Hz or exceed 51 Hz.

Figure 51 Case 8, Tamworth contingency, 132 kV lines tripped: system frequency traces

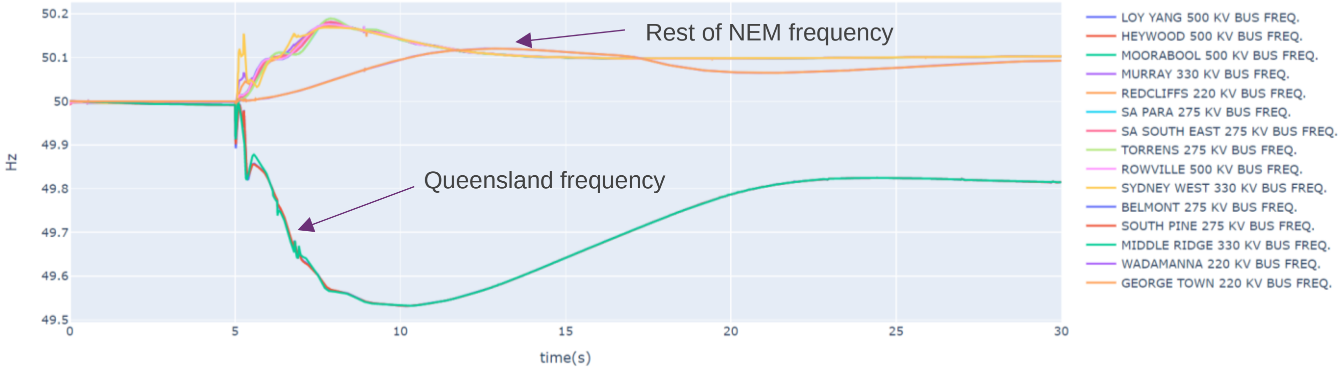
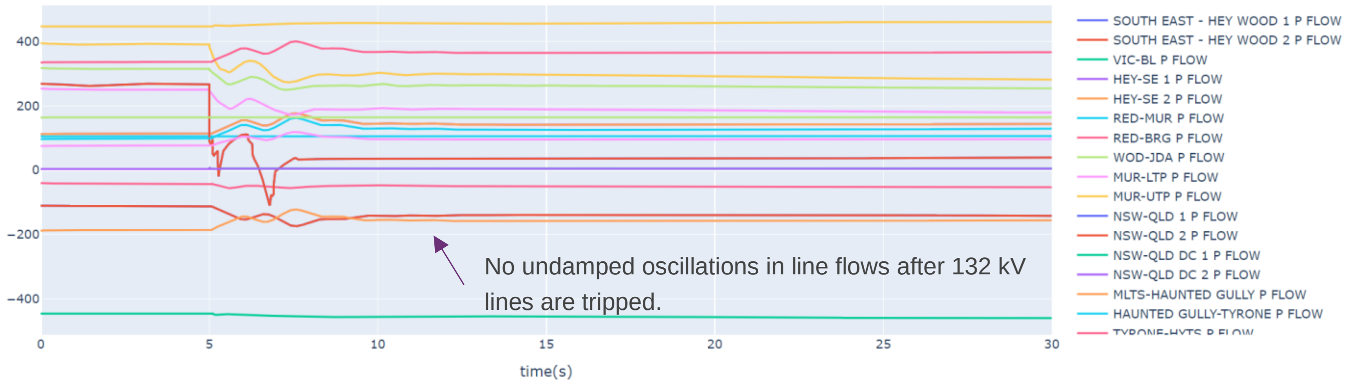


Figure 52 Case 8, Tamworth contingency, 132 kV lines tripped: line active power flows



Case 13 – 01/06/2022 1300 hrs

The simulation results for Case 13 are shown in the figures below. The EAPT scheme (in mode 3) was found to operate to island South Australia as a result of this contingency and QNI losing stability due to the summated active power flow to South Australia through the Heywood transformers dropping below the threshold of 20 MW for more than 2 s and the Heywood – South East 275 kV line frequency dropping below 49.7 Hz for more than 100 ms. The AUFLS2 scheme also operates in Tasmania, resulting in load shedding.

Figure 53 Case 13, Tamworth contingency: generator active power outputs

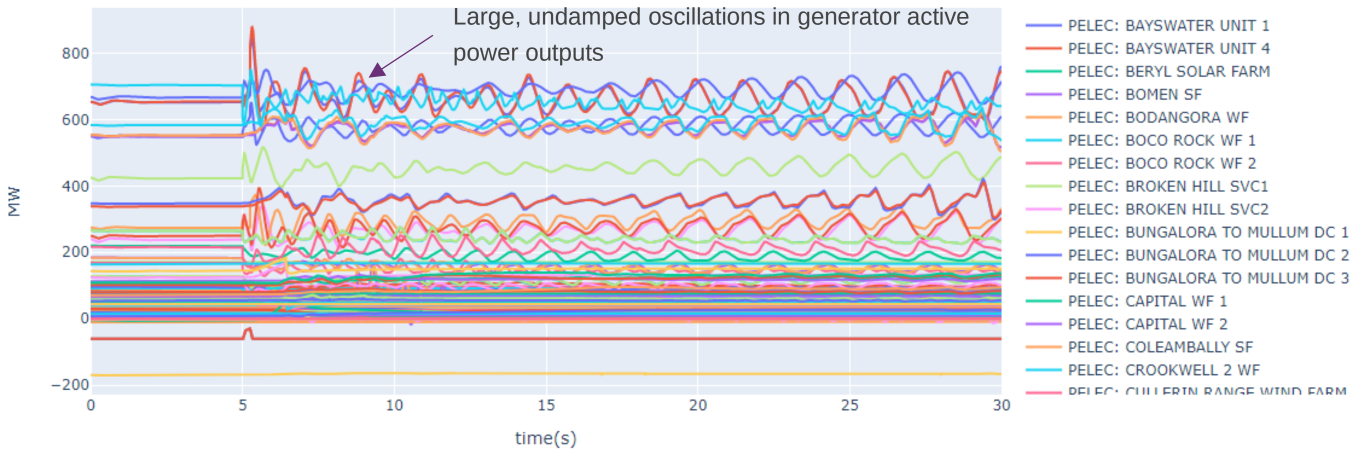


Figure 54 Case 13, Tamworth contingency: system frequency traces

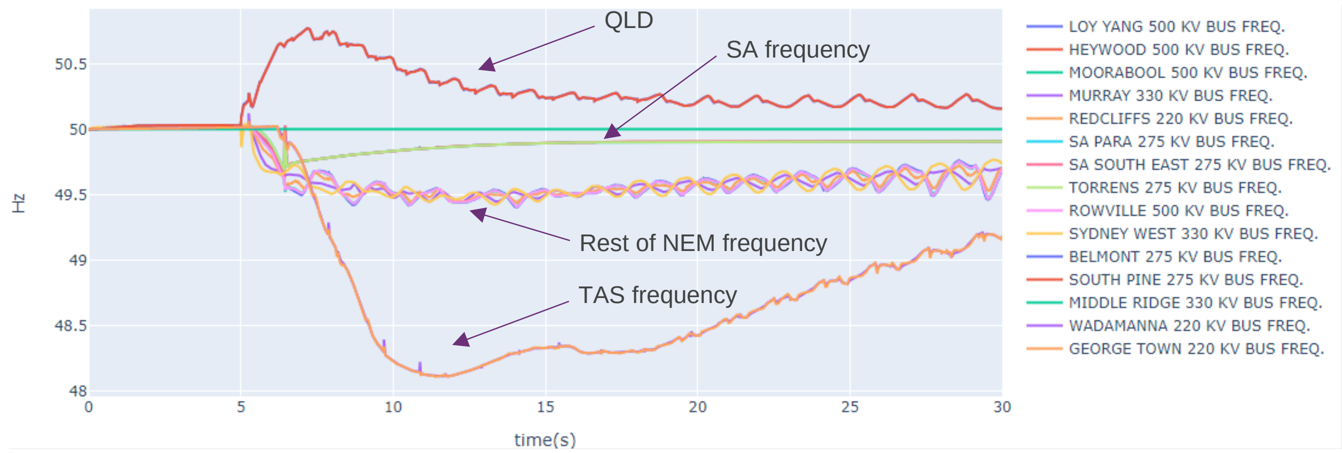
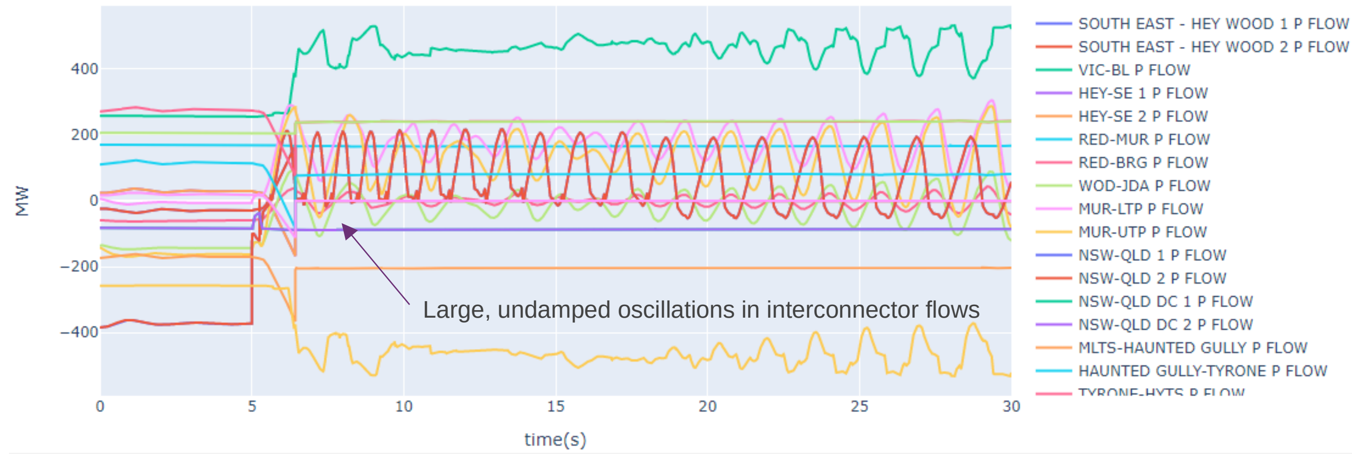


Figure 55 Case 13, Tamworth contingency: line active power flows



Case 14 – 29/08/2021 1030 hrs

The simulation results for Case 14 are shown in the figures below. Case 14 crashed after 5.58 s following fault clearance. The Queensland system angle separated from the rest of the NEM and the QNI distance protection operated for zone 1 at 5.58 s (however, the case crashed before the protection tripped the lines). QNI transfer into New South Wales was near its limit at 1,120 MW.

Figure 56 Case 14, Tamworth contingency: system angles

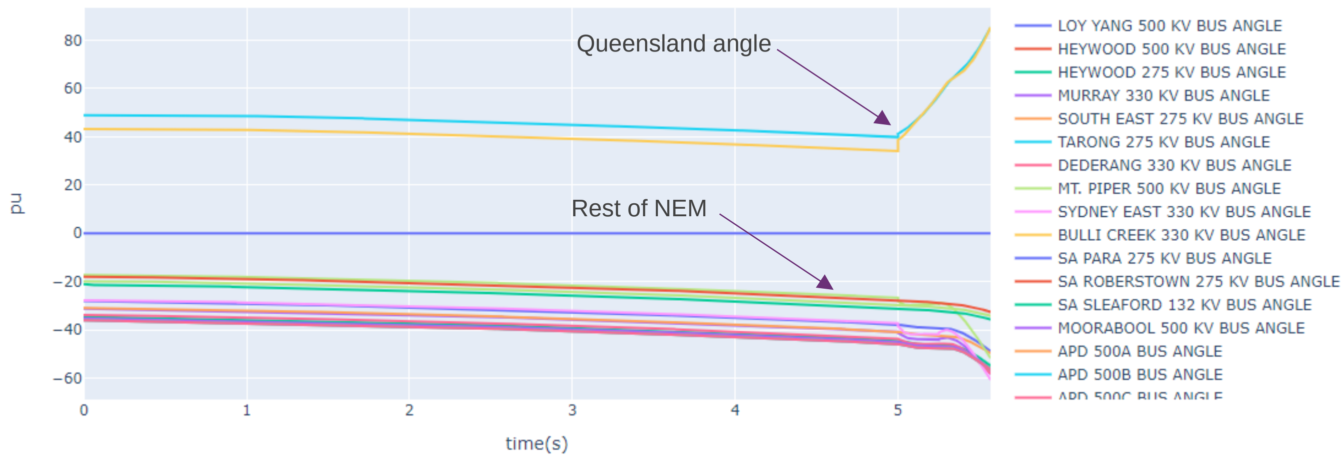


Figure 57 Case 14, Tamworth contingency: generator active power outputs

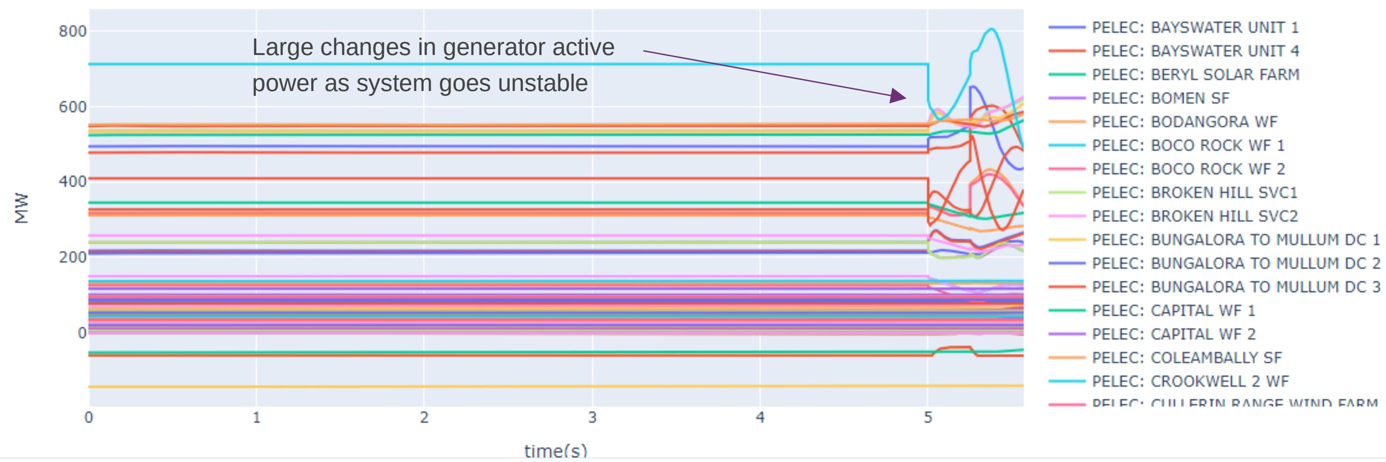


Figure 58 Case 14, Tamworth contingency: system frequency traces

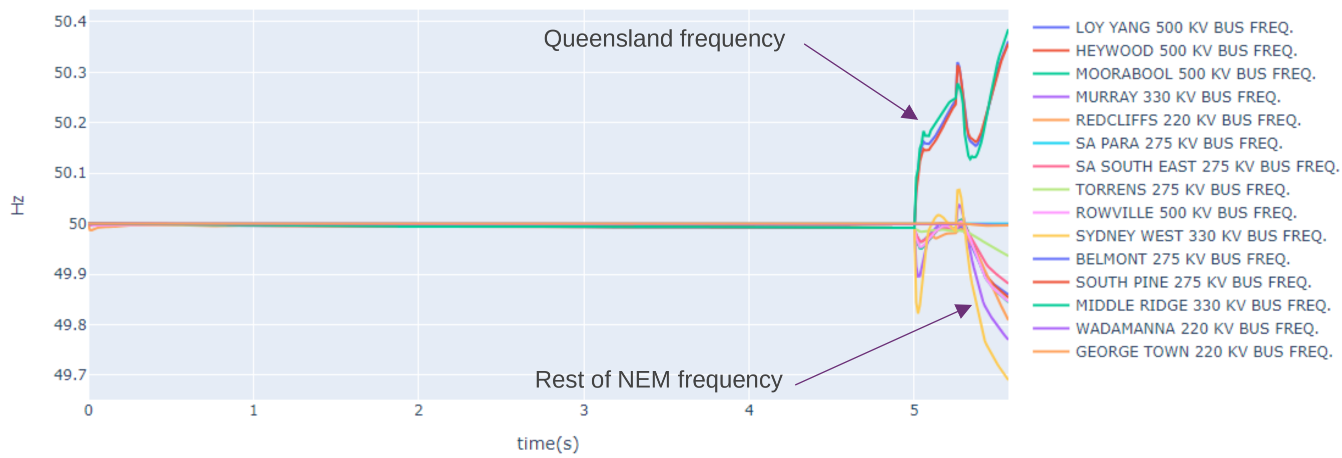
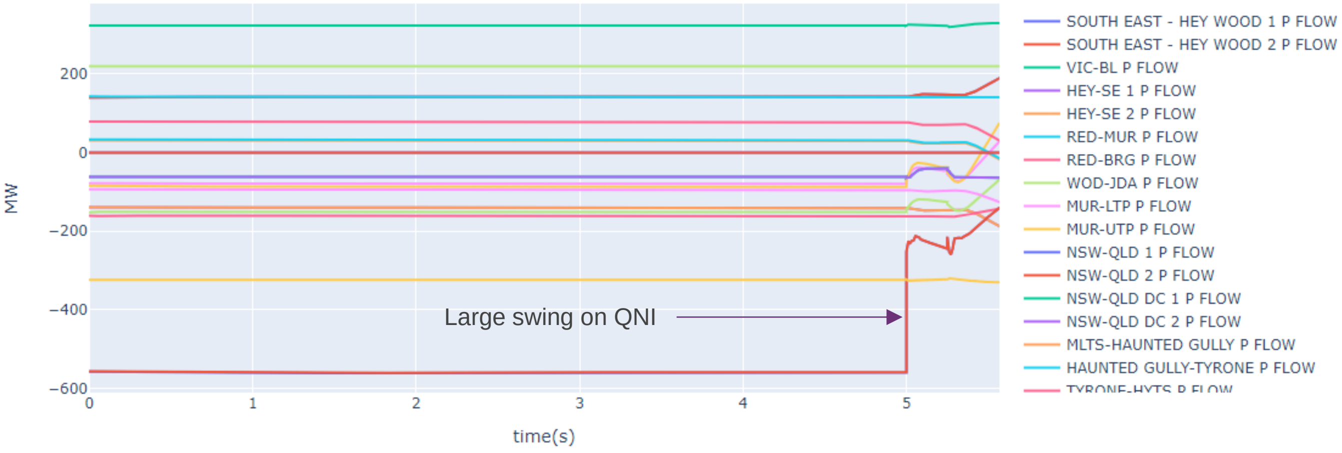


Figure 59 Case 14, Tamworth contingency: line active power flows



Case 14 was rerun with reduced QNI flow (transfer was approximately 100 MW), the case completed and QNI remained stable following fault clearance. The simulation results are shown in the figures below.

Figure 60 Case 14, Tamworth contingency, lower QNI flow: system angles

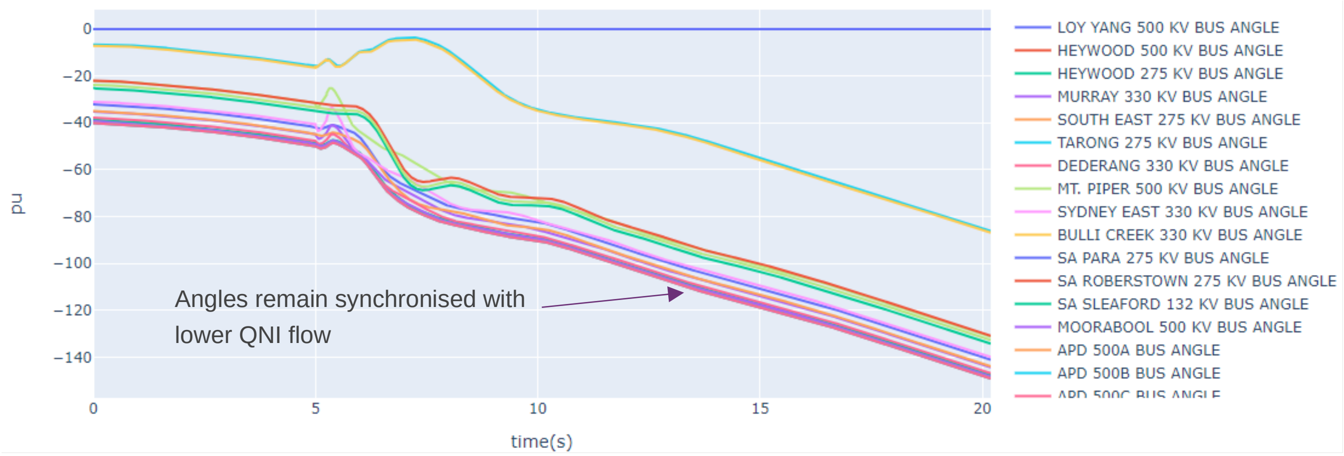


Figure 61 Case 14, Tamworth contingency, lower QNI flow: generator active power outputs

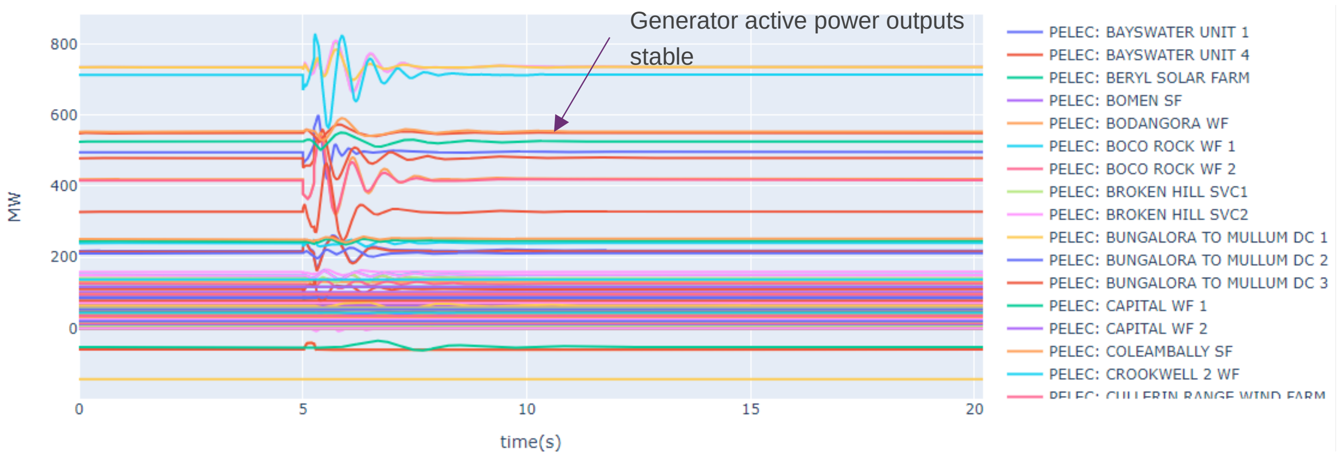


Figure 62 Case 14, Tamworth contingency, lower QNI flow: system frequency traces

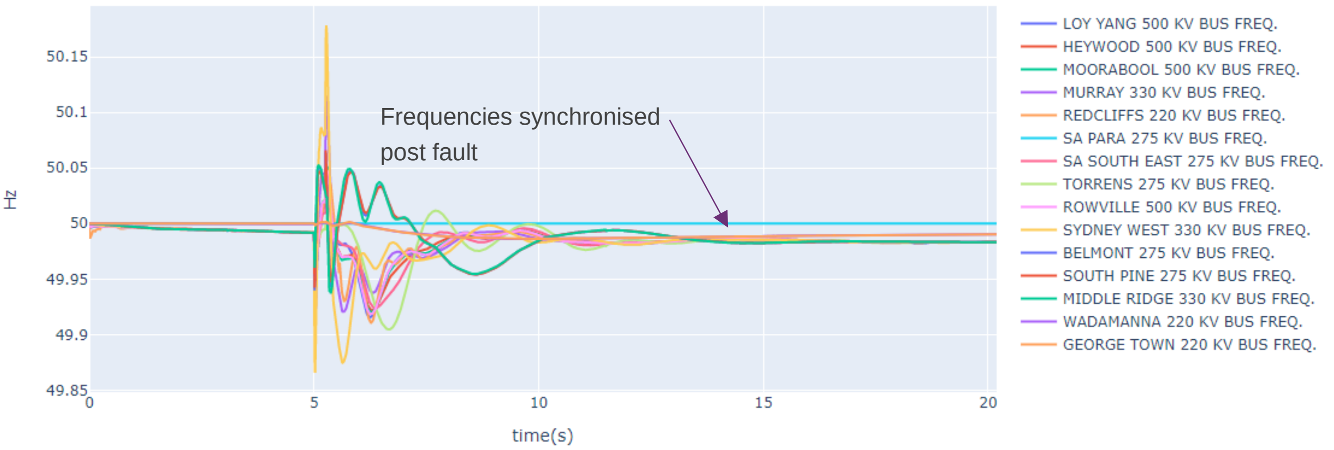
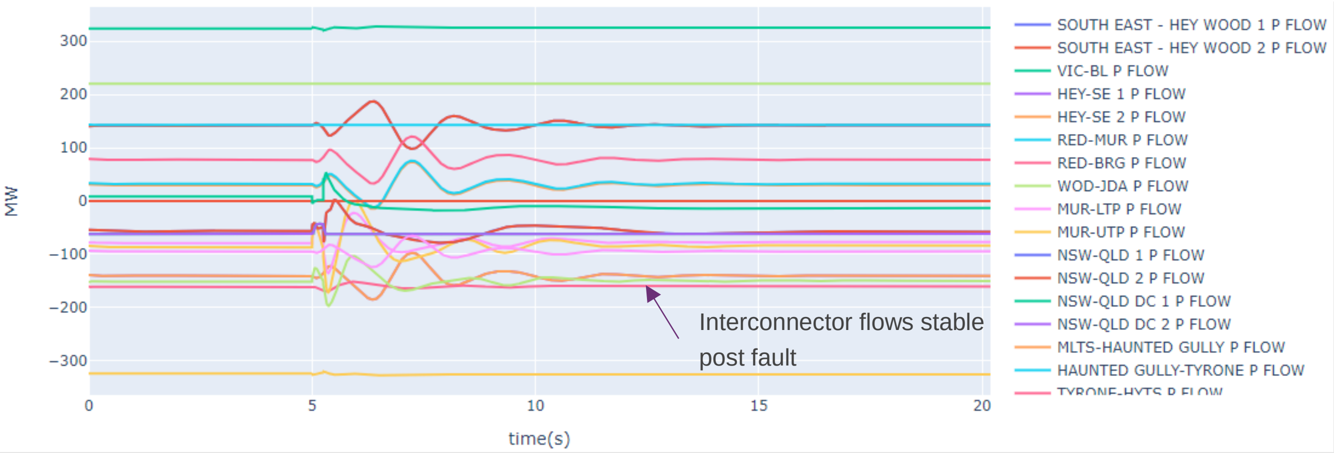


Figure 63 Case 14, Tamworth contingency, lower QNI flow: line active power flows



Case 15 – 30/07/2021 0900 hrs

The simulation results for Case 15 for the Tamworth contingency are shown in the figures below. QNI lost stability and the Queensland system angle separated from the rest of the NEM following fault clearance, but the QNI distance protection did not operate to separate Queensland due to the current falling below the threshold. Hence, sustained, undamped power swings on QNI were observed. This case also results in load shedding in Tasmania due to the frequency impact on the Tasmanian system.

Figure 64 Case 15, Tamworth contingency: generator active power outputs

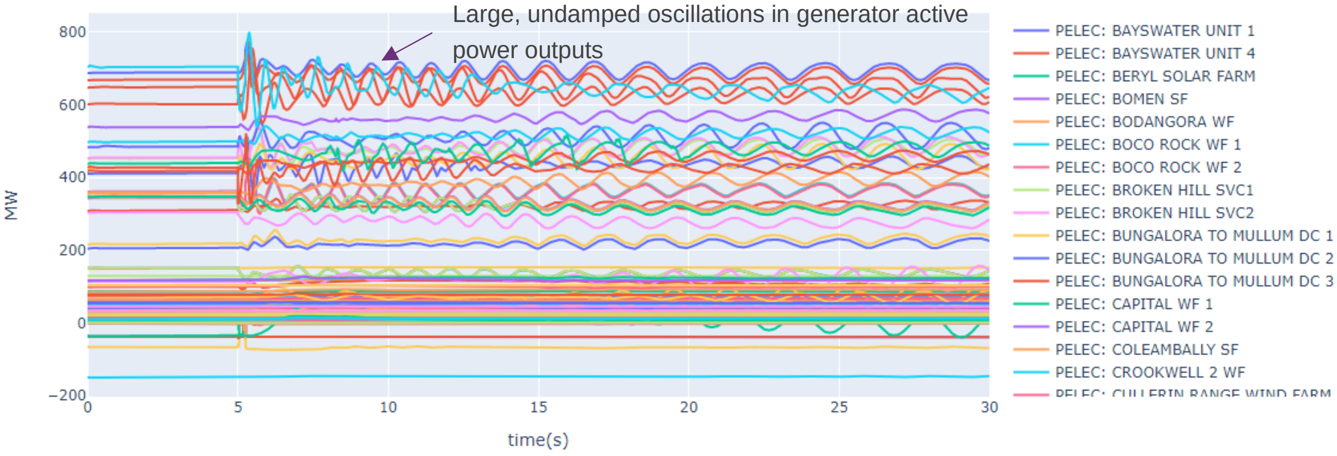


Figure 65 Case 15, Tamworth contingency: system frequency traces

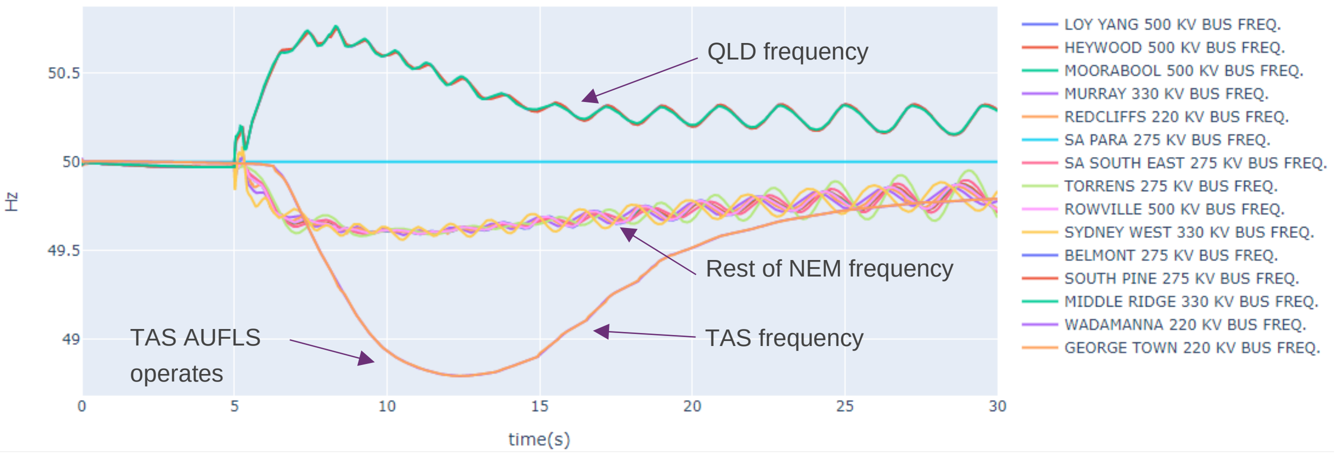
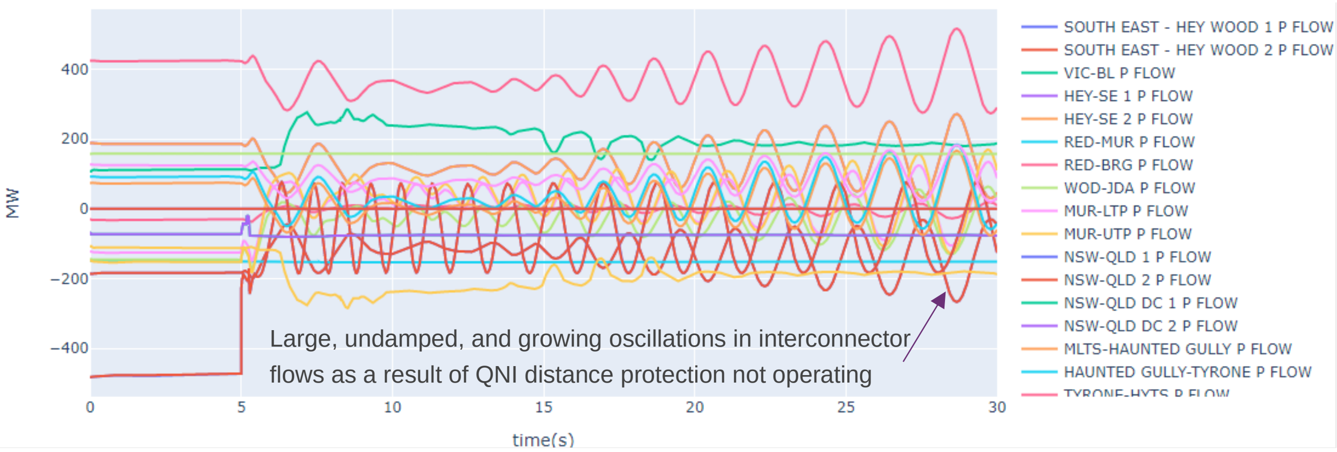


Figure 66 Case 15, Tamworth contingency: line active power flows



Case 15 was rerun tripping the 132 kV lines between Kempsey and Taree, and Moree and Inverell. The simulation results are shown in the figures below. Queensland successfully separated from the rest of the NEM and Queensland frequency did not fall below 49 Hz or exceed 51 Hz. AUFLS operates in Tasmania, resulting in load shedding.

Figure 67 Case 15, Tamworth contingency, 132 kV lines tripped: system frequency traces

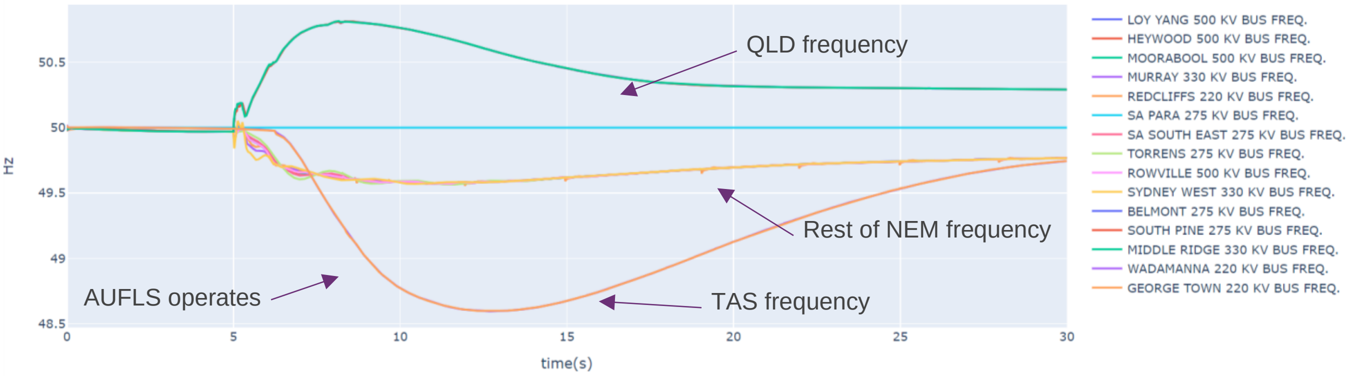
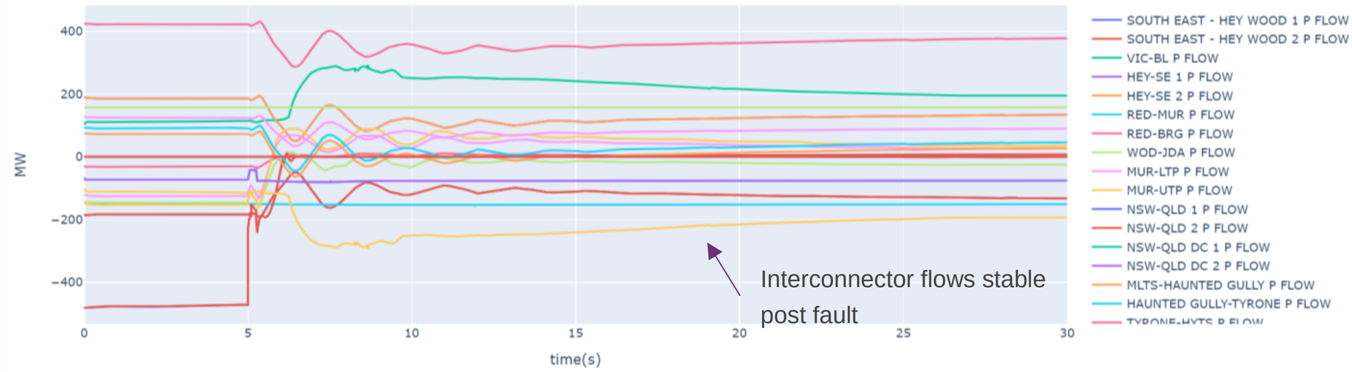


Figure 68 Case 15, Tamworth contingency, 132 kV lines tripped: line active power flows



A5.3 Risk 3: Mount Piper contingency

A5.3.1 Study results

The key results of the non-credible loss of Bayswater – Mount Piper (5A3) and Mount Piper – Wollar (5A5) 500 kV lines simulation studies are given Table 21.

Table 21 Case results for the Mount Piper contingency

Case	NSW/NEM frequency nadir/peak (Hz)	NSW total DPV tripped on DPV inverter settings only (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
1	50.2	83 (11%)	None	Yes
2	50.1	443 (14%)	None	Yes*
3	50.2	0 (NA)	None	Yes
4	50.1	358 (13%)	None	Yes
5	50.1	206 (9%)	None	Yes
6	50.2	0 (NA)	None	Yes*
7	50.1	427 (13%)	None	Yes*
8	50.2	0 (NA)	None	Yes
9	50.1	221 (11%)	None	Yes
10	50.1	309 (18%)	None	Yes*

Case	NSW/NEM frequency nadir/peak (Hz)	NSW total DPV tripped on DPV inverter settings only (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
11	50.1	219 (12%)	None	Yes*
12	50.1	473 (14%)	None	Yes
13	50.1	249 (11%)	None	Yes
14	50.1	182 (13%)	None	Yes
15	50.1	141 (12%)	None	Yes

A5.3.2 Representative results

Case 10 – 12/02/2022 1400 hrs

The simulation results for Case 10 for the Mount Piper contingency are shown in the figures below.

309 MW (18%) of DPV was tripped on its own inverter settings in New South Wales following fault clearance.

Figure 69 Case 10, Mount Piper contingency: generator active power outputs

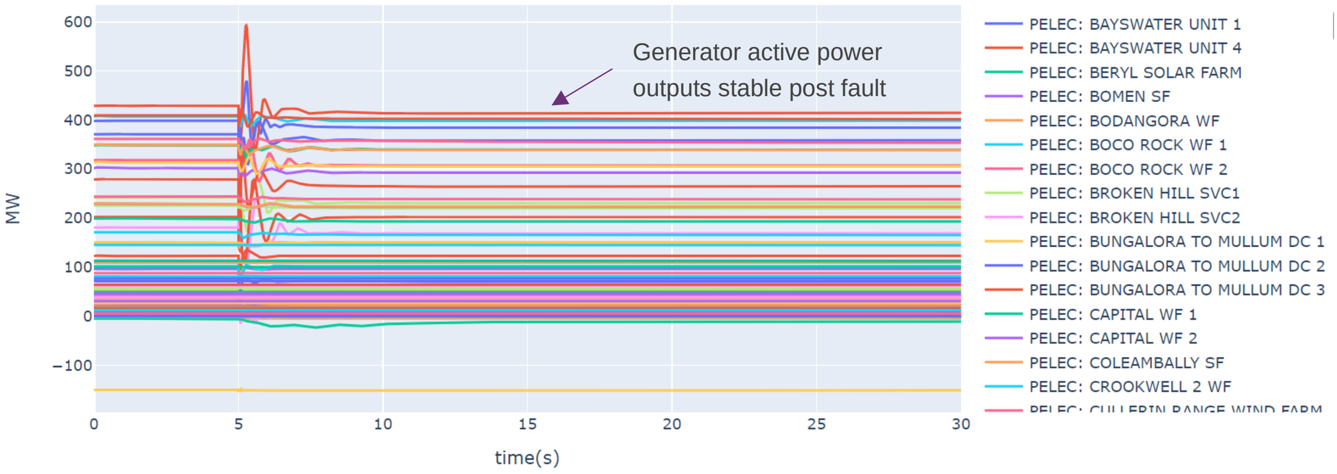


Figure 70 Case 10, Mount Piper contingency: system frequency traces

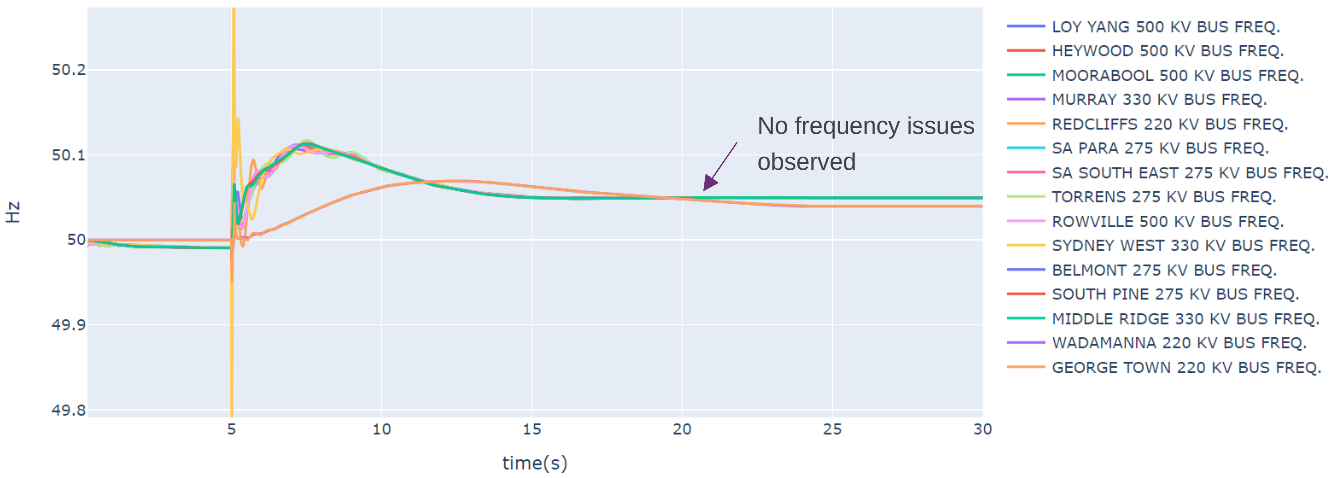
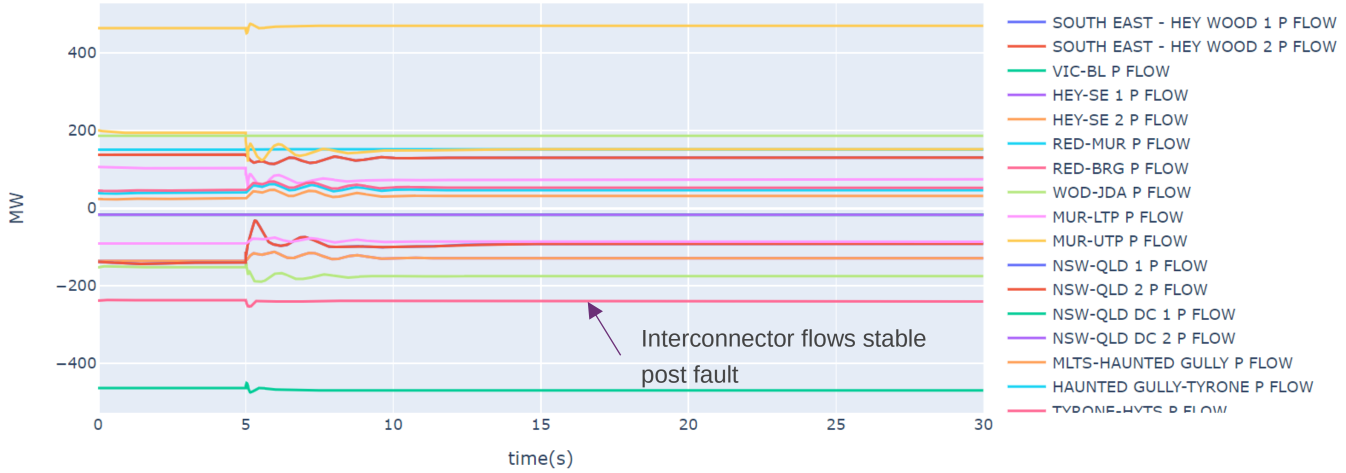


Figure 71 Case 10, Mount Piper contingency: line active power flows



A6. Simulation results for future studies (Risk 4)

This section gives detailed references to study cases, results, and key result graphs for contingencies that could lead to QNI instability to supplement the observations provided in Section 5.

A6.1 Risk 4a: Moorabool contingency

A6.1.1 Study results

The key results of the South Australia separation at MLTS with EAPT operation included simulation studies are given Table 22.

Table 22 Case results for the Moorabool contingency

Case	Heywood + PEC flow (SA import +ve) (MW)	SA freq. nadir/peak (Hz)	QLD freq. nadir/ peak (Hz)	QLD initial RoCoF (Hz/s)	NSW/ VIC freq. nadir/ peak (Hz)	SA OFGS tripped (MW)	Net UFLS tripped (MW)	DPV tripped on inverter settings only (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
1	1,300	40	48.2	0.82	51	0	SA: 1,398 (99%) QLD: 1,290 (59%) - -	SA: 17 QLD: 166 VIC: 237 NSW: 188	EAPT, SAIT RAS (560 MW load tripped), QNI distance protection	No – SA angular separation, QNI tripped
2	123	50.1	50.1	0.02	50.1	0	0	0	EAPT	Yes
3	-215	49.9	49.9	0.04	49.9	0	0	0	EAPT[44]	Yes
4	156	50.1	50.1	0.05	50.1	0	0	0	EAPT	Yes
5	184	50.3	50.3	0.09	50.3	0	0	0	EAPT	Yes
6	-625	50.1	50.1	0.07	50.1	0	SA: 29 (9%)	SA: 132	EAPT[44]	Yes
7	-75	48.7	51.3	1.06	48.7	0	SA: 351 (24%) - VIC: 1,168 (22%) NSW: 1,079 (31%)	SA: 32 QLD: 232 VIC: 61 NSW: 327	EAPT[44], QNI distance protection	No – QNI tripped
8	-900	52	51.2	0.27	48.7	31	VIC: 765 (17%) NSW: 986 (29%)	0	SAIT RAS (144 MW of generation tripped), QNI	No – SA angular separation, QNI tripped

Case	Heywood + PEC flow (SA import +ve) (MW)	SA freq. nadir/peak (Hz)	QLD freq. nadir/ peak (Hz)	QLD initial RoCoF (Hz/s)	NSW/ VIC freq. nadir/ peak (Hz)	SA OFGS tripped (MW)	Net UFLS tripped (MW)	DPV tripped on inverter settings only (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
									distance protection	
9	-626	52	51.2	0.70	48.8	36	VIC: 766 (17%) NSW: 960 (24)	0	QNI distance protection	No – SA angular separation, QNI tripped
10	-499	53	50.9	0.88	48.4	204	SA: 1,569 (89%) VIC: 1,941 (44%) NSW: 1,494 (36%)	QLD: 132 VIC: 10 NSW: 93	EAPT[44], QNI distance protection	No – SA angular separation, QNI tripped
11	200	49.9	49.9	0.03	49.9	0	0	0	None	Yes
12	-1,261	53	51	1.54	48	0	SA: 13 (5%) - VIC: 2,364 (69%) NSW: 1,230 (48%)	SA: 73 QLD: 166 VIC: 105 NSW: 856	EAPT[44], SAIT RAS (510 MW of generation tripped), QNI distance protection	No – SA angular separation, QNI tripped

A6.1.2 Representative results

Case 1 – 19/03/2028 1200 hrs

For Case 1, for which QNI was at the maximum import into Queensland, South Australia lost angular stability with the rest of the NEM following separation at Moorabool, and the QNI power flow swung to approximately 1,400 MW before tripping. EAPT operated at 5.3 s following the South Australia frequency dropping below 49.7 Hz, tripping the Heywood lines. The South Australia import level was high enough to trigger SAIT RAS load tripping action. The SAIT RAS tripped a total of 560 MW of load in South Australia, 250 ms after fault clearance.

[44] Note that in some cases the EAPT operated due to the down spike in South Australia frequency dropping below 49.7 Hz for more than the EAPT performance criteria delay time of 170 ms.

Figure 72 Case 1, South Australia separation at MLTS: system frequency traces

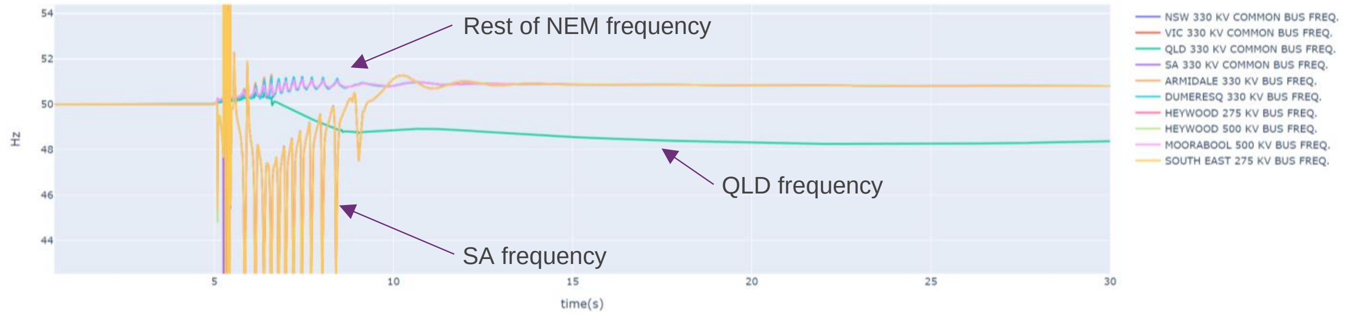


Figure 73 Case 1, South Australia separation at MLTS: line active power flows

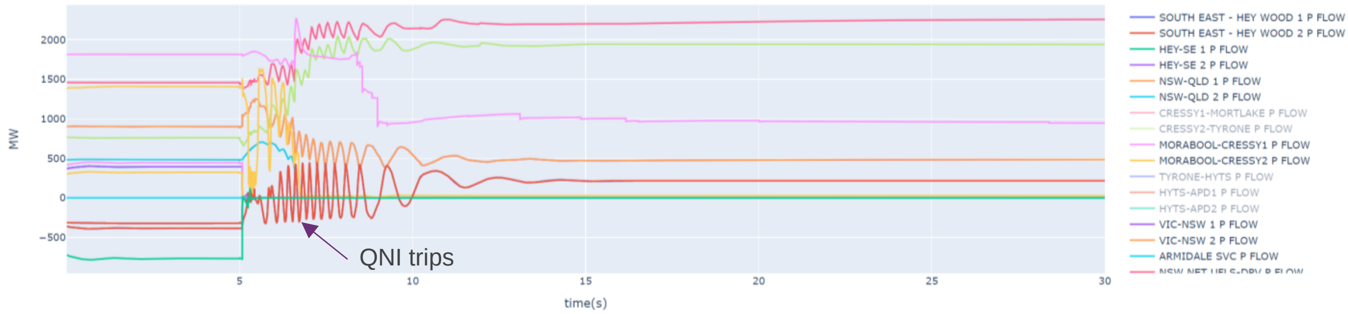
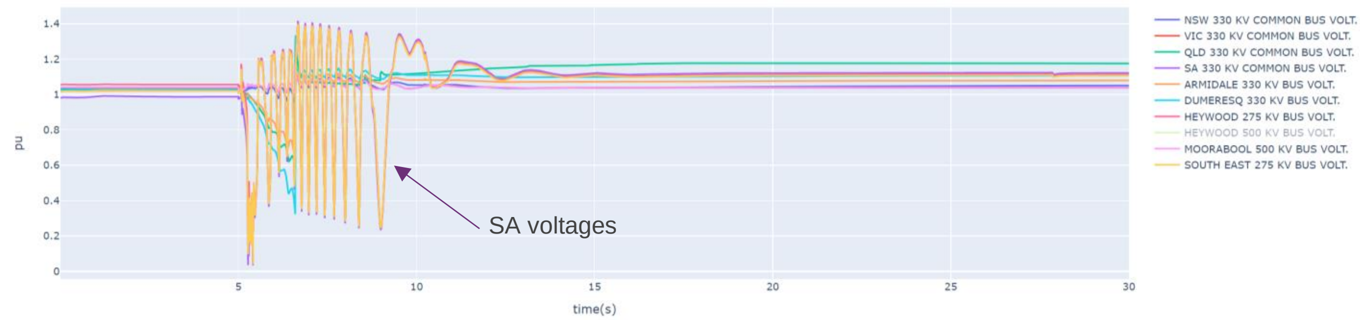


Figure 74 Case 1, South Australia separation at MLTS: system bus voltages



Case 12 – 24/07/2027 1130 hrs

For Case 12, the South Australia export level was high enough to trigger SAIT RAS generator tripping action. The SAIT RAS tripped a total of 510 MW of IBR generation, 250 ms after fault clearance. South Australia lost angular stability with the rest of the NEM following separation at Moorabool, prior to QNI being tripped by distance protection.

Figure 75 Case 12, South Australia separation at MLTS: system frequency traces

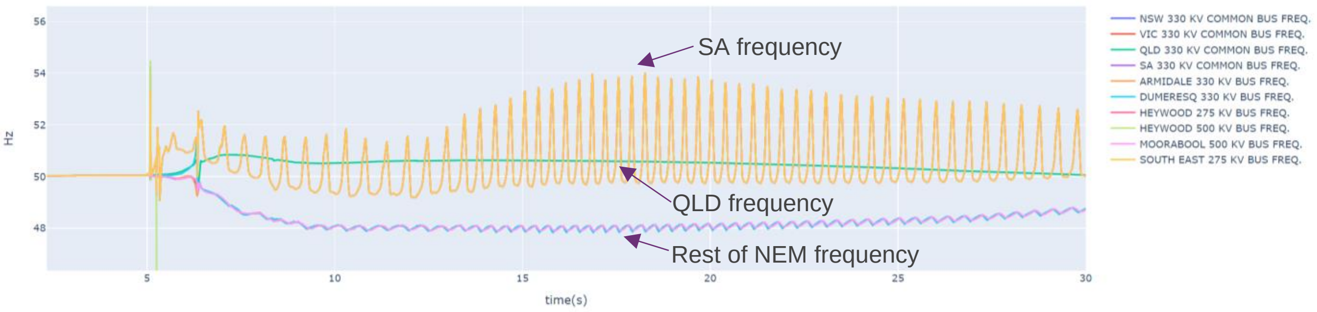


Figure 76 Case 12, South Australia separation at MLTS: line active power flows

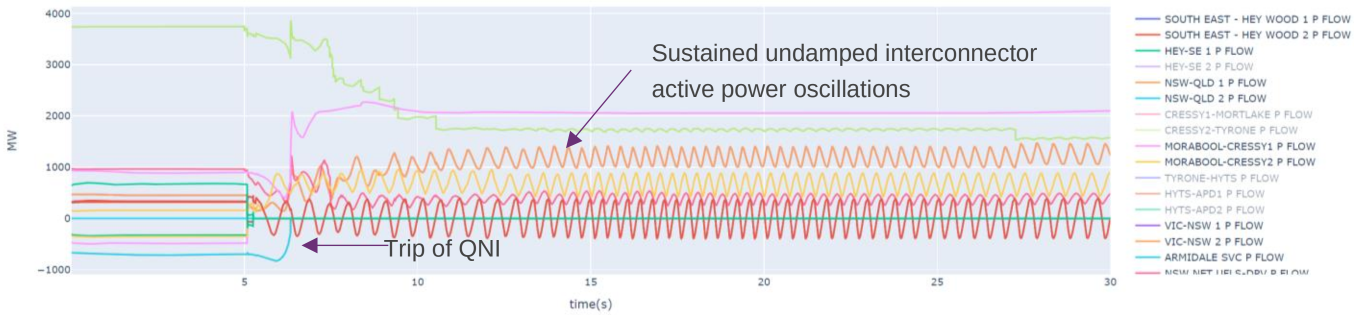
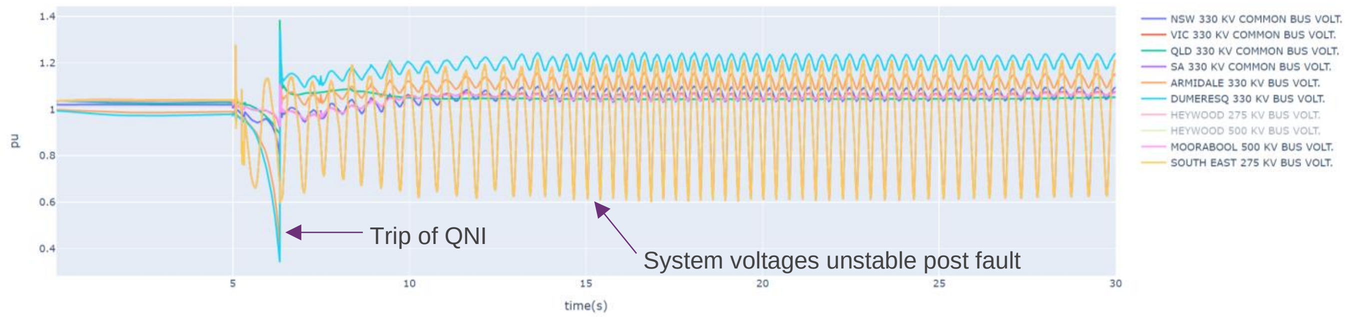


Figure 77 Case 12, South Australia separation at MLTS: system bus voltages



Case 9 with APD load tripping – 1/02/2028 1930 hrs

For Case 9, QNI was at the maximum export level from Queensland. The QNI power flow swung to approximately 1,700 MW before tripping. As detailed in Appendix A3.2.8, sensitivities were completed tripping the APD load following fault clearance for Case 8 and Case 9 where South Australia was exporting and EAPT did not operate. For Case 9, South Australia frequency then exceeds 52 Hz following separation at Moorabool.

Figure 78 Case 9, South Australia separation at MLTS with APD load tripping: system frequency traces

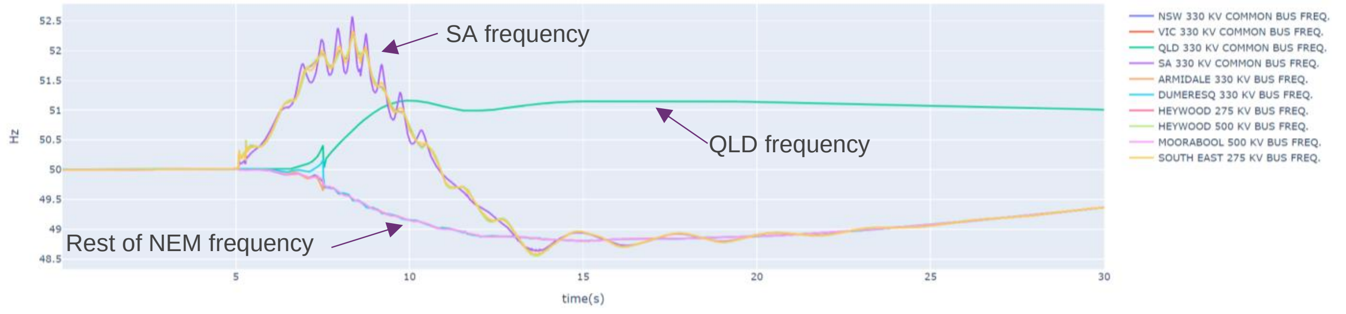


Figure 79 Case 9, South Australia separation at MLTS with APD load tripping: line active power flows

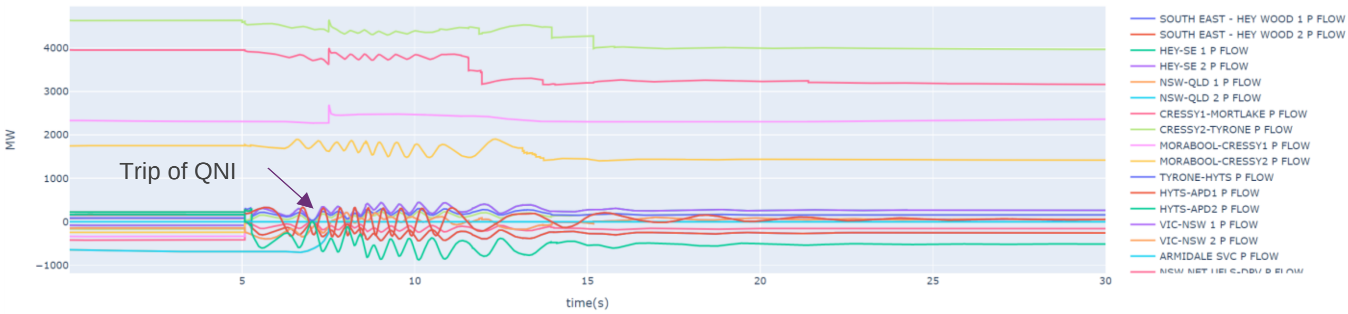
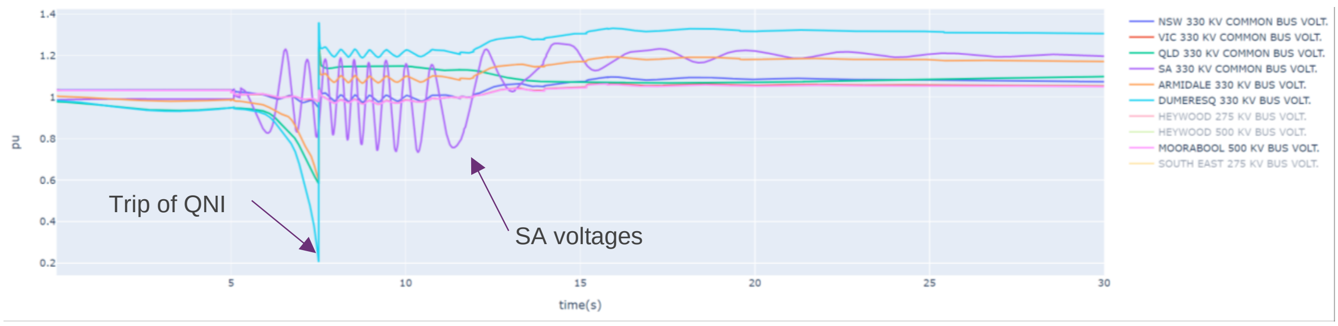


Figure 80 Case 9, South Australia separation at MLTS with APD load tripping: system bus voltages



A6.2 Risk 4b: Loy Yang contingency

A6.2.1 Study results

The key results of the fault on Loy Yang B transformer with No. 3 bus 500 kV circuit breaker failure simulation studies are given in Table 23.

Table 23 Case results for the Loy Yang contingency

Case	Loy Yang + Valley Power generation tripped (MW)	NEM frequency nadir/peak (Hz)	QLD frequency nadir/peak (Hz)	QLD initial RoCoF (Hz/s)	Net NEM UFLS tripped (MW)	DPV tripped on inverter settings only (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
1	320	49.64	49.64	0.05	0 (0%)	0	None	Yes

Case	Loy Yang + Valley Power generation tripped (MW)	NEM frequency nadir/peak (Hz)	QLD frequency nadir/peak (Hz)	QLD initial RoCoF (Hz/s)	Net NEM UFLS tripped (MW)	DPV tripped on inverter settings only (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
2	1,087	49.5	49.5	0.11	0 (0%)	24	None	Yes
3	640	49	49	0.09	791 (6.1%)	505	None	Yes
4	640	49	49	0.11	2,473 (16%)	2,143	None	Yes
5	1,119	48.87	48.87	0.32	2,257 (16%)	1,593	None	Yes
6	640	47.9	50.88	0.89	2,520 (46%)	1,342	QNI distance protection	No – QNI distance protection operated to trip QNI.
7	580	48.7	51.28	1.21	2,587 (20%)	578	QNI distance protection	No – QNI distance protection operated to trip QNI.
8	1,390	48.8	51.2	0.69	3,018 (25%)	0	QNI distance protection	No – SA angular separation, QNI tripped
9	1,027	48.85	51.16	0.91	1,254 (10%)	3	QNI distance protection	No – QNI distance protection operated to trip QNI.
10	640	48.76	51	0.89	1,955 (18%)	284	QNI distance protection	No – QNI distance protection operated to trip QNI.
11	1,154	48.93	51.46	0.59	1,232 (11%)	0	QNI distance protection	No – QNI distance protection operated to trip QNI.
12	640	48.3	50.9	0.73	2,862 (33%)	1,194	QNI distance protection	No – QNI distance protection operated to trip QNI.

Case 12 – 24/07/2027 1130 hrs

In Case 12, the QNI distance protection operated to trip QNI, resulting in synchronous separation of Queensland from the rest of the NEM. QNI was near the maximum export level from Queensland. The QNI power flow swung to approximately 1,700 MW before tripping. The total contingency size of the tripped Loy Yang B and Valley Power generation units was 640 MW.

Figure 81 Case 12, Loy Yang contingency: system frequency traces

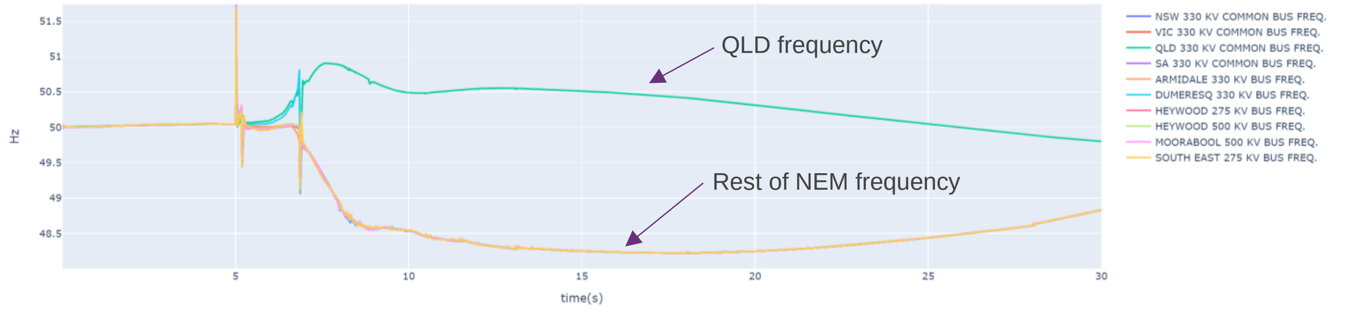


Figure 82 Case 12, Loy Yang contingency: line active power flows

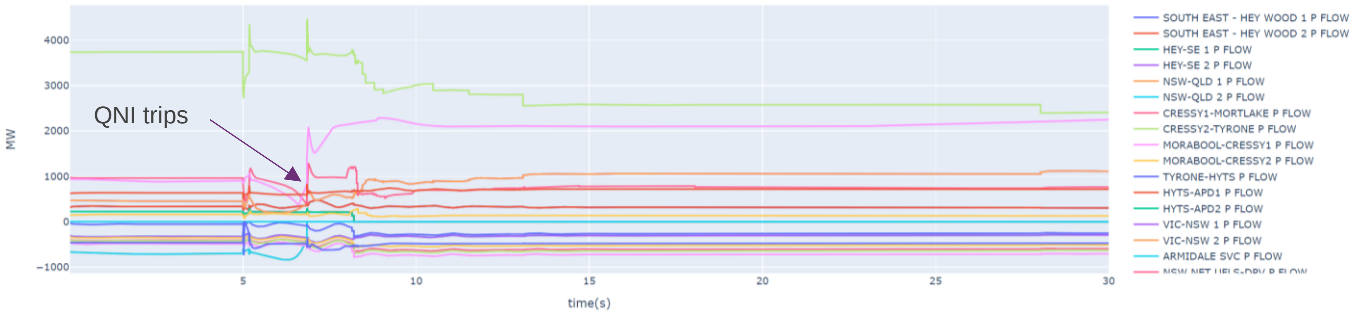
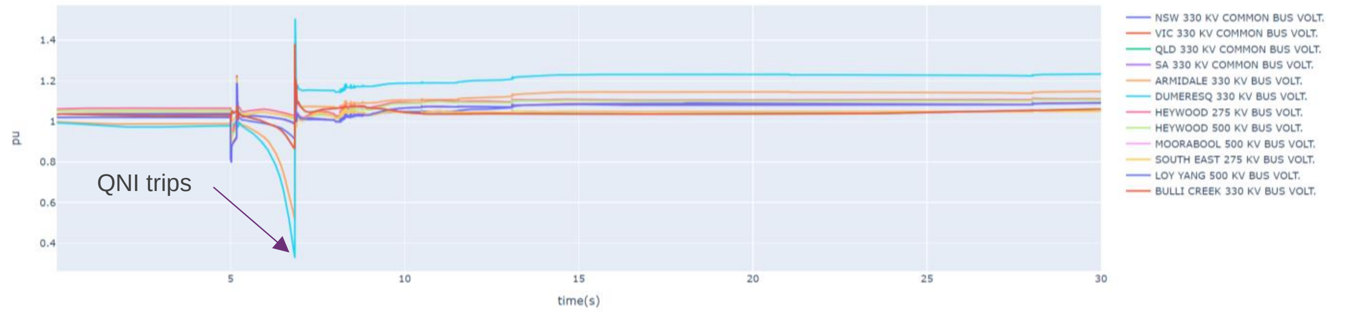


Figure 83 Case 12, Loy Yang contingency: system bus voltages



Case 6 – 1/05/2028 1100 hrs

In Case 6, the QNI distance protection operated to trip QNI, resulting in synchronous separation of Queensland from the rest of the NEM. QNI was near the maximum export level from Queensland. The QNI power flow swung to approximately 1,700 MW before tripping. The total contingency size of the tripped Loy Yang B and Valley Power generation units was 640 MW. The NEM frequency fell to 47.9 Hz following the separation of Queensland, resulting in under frequency load shedding.

Figure 84 Case 6, Loy Yang contingency: system frequency traces

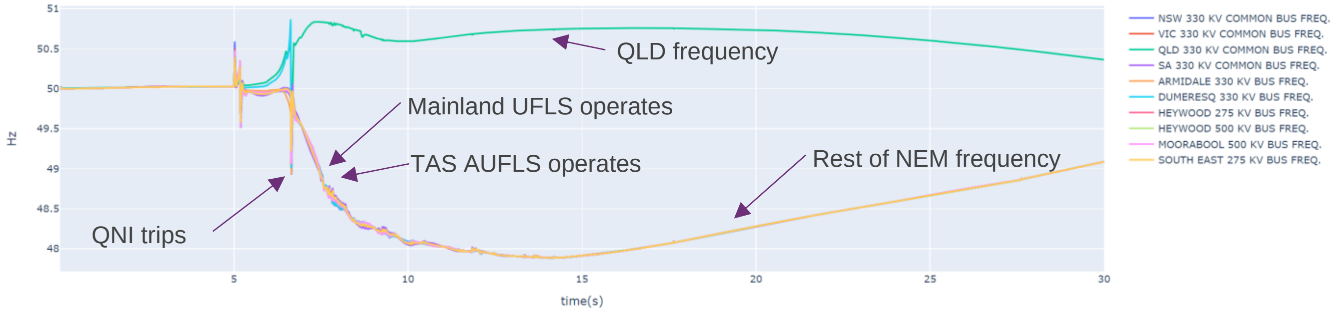


Figure 85 Case 6, Loy Yang contingency: line active power flows

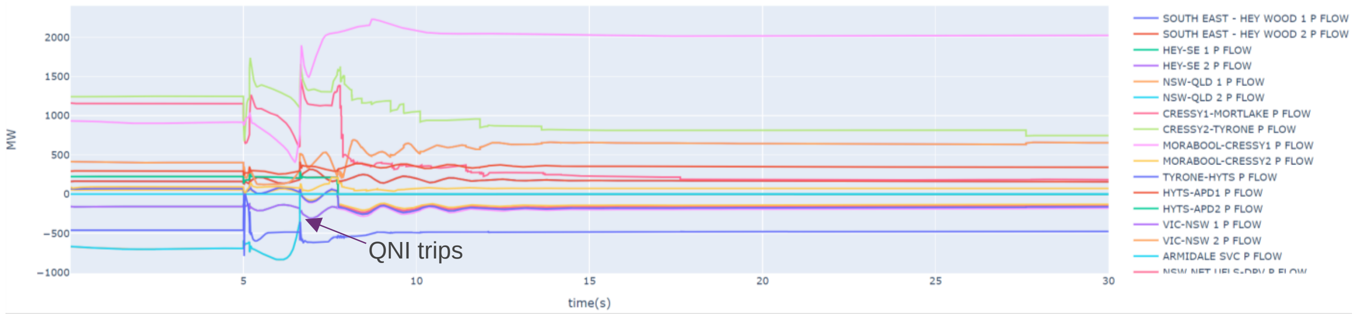
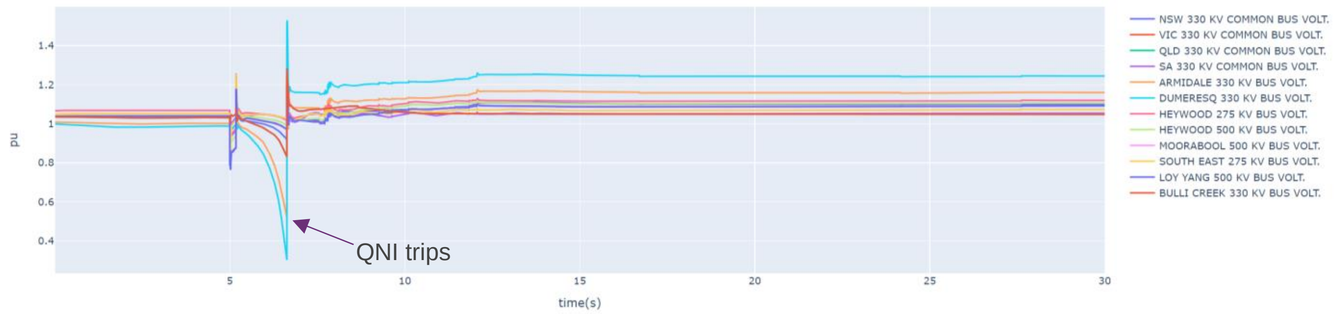


Figure 86 Case 6, Loy Yang contingency: system bus voltages



Case 4 – 14/01/2028 1130 hrs

In Case 4, NEM frequency fell below 49 Hz and a total of 2,452 MW of DPV was tripped on inverter settings across the mainland NEM. This also resulted in under frequency load shedding across the NEM.

Figure 87 Case 4, Loy Yang contingency: system frequency traces

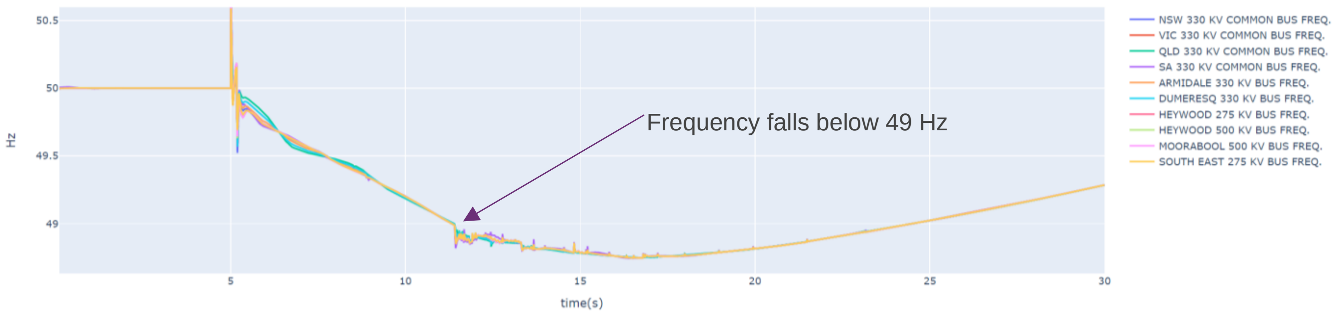


Figure 88 Case 4, Loy Yang contingency: line active power flows

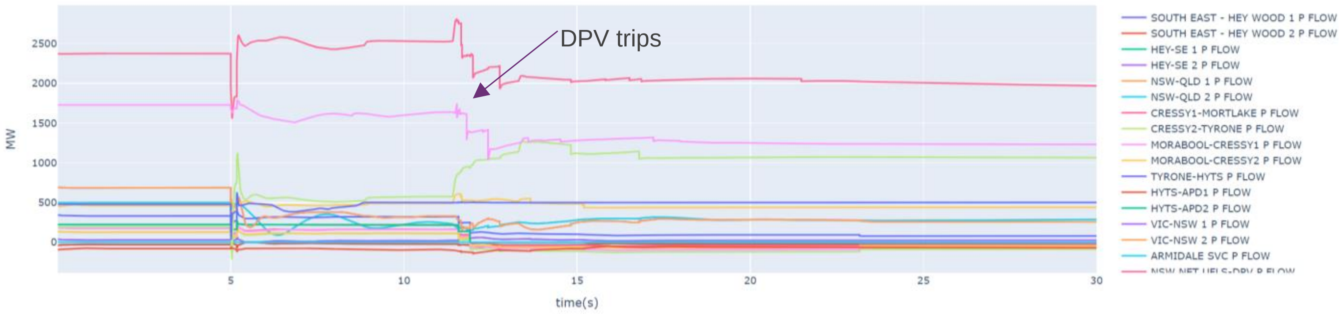
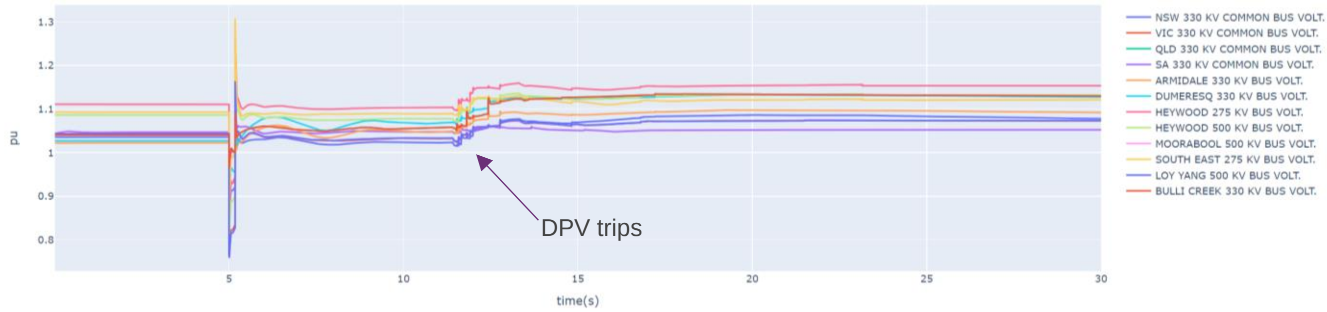


Figure 89 Case 4, Loy Yang contingency: system bus voltages



A6.3 Risk 4c: Millmerran contingency

A6.3.1 Study results

The key results of the large amount of generation and DPV loss in Southern Queensland simulation studies are given Table 24.

Table 24 Case results for the Millmerran contingency

Case	Millmerran generation tripped (MW)	DPV generation tripped (MW)	NEM frequency nadir/peak (Hz)	QLD frequency nadir/peak (Hz)	QLD initial RoCoF (Hz/s)	Net mainland NEM UFLS tripped (MW)	DPV tripped on inverter settings only (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
1	671	201	50.42	<47	1.39	1,811 (87%)	1,456	QNI distance protection	No – QNI distance protection operated to trip QNI.
2	672	16	49.84	49.84	0.07	0 (0%)	0	None	Yes
3	665	103	50.5	47.3	1.97	2,027 (87%)	267	QNI distance protection	No – QNI distance protection operated to trip QNI.
4	654	500	50.35	<47	1.96	1,691 (74%)	3,480	QNI distance protection	No – QNI distance protection operated to trip QNI.

Case	Millmerran generation tripped (MW)	DPV generation tripped (MW)	NEM frequency nadir/peak (Hz)	QLD frequency nadir/peak (Hz)	QLD initial RoCoF (Hz/s)	Net mainland NEM UFLS tripped (MW)	DPV tripped on inverter settings only (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
5	765	235	50.35	<47	1.94	1,967 (87%)	1,441	QNI distance protection	No – QNI distance protection operated to trip QNI.
6	674	468	48.79	48.79	0.85	2,536 (25%)	1,652	None	Yes
7	612	310	48.9	48.9	0.63	2,166 (14%)	484	None	Yes
8	672	0	49.8	49.8	0.10	0	0	None	Yes
9	672	0	49.8	49.8	0.09	0 (0%)	0	None	Yes
10	688	186	48.97	48.97	0.33	1,058 (9%)	244	None	Yes
11	757	0	49.79	49.79	0.08	0 (0%)	0	None	Yes
12	670	478	48.81	48.81	0.84	2,166 (17%)	1,485	None	Yes

A6.3.2 Representative results

Case 1 – 19/03/2028 1200 hrs

In Case 1, the QNI distance protection operated to trip QNI, resulting in synchronous separation of Queensland from the rest of the NEM. QNI was around the maximum import level into Queensland. The QNI power flow swung to approximately 1,360 MW before tripping. The total contingency size of the tripped Millmerran generation tripped was 671 MW. Following separation, the Queensland frequency fell below 47 Hz.

Figure 90 Case 1, Millmerran contingency: system frequency traces

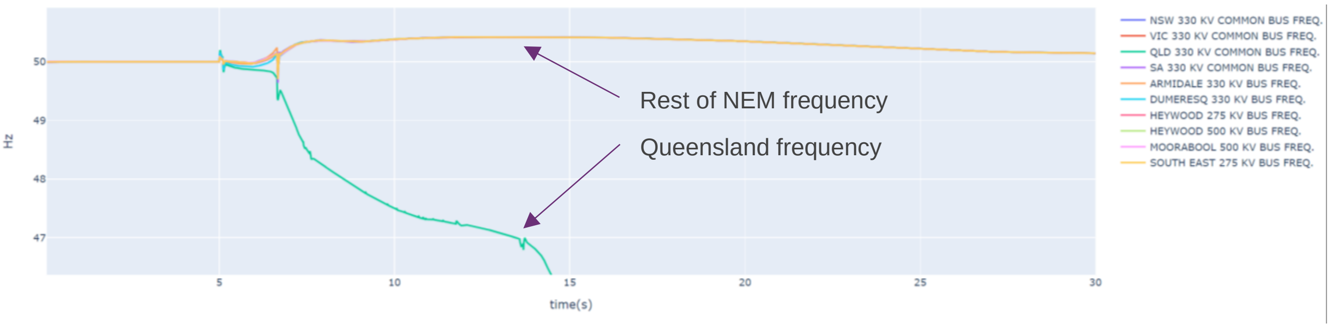


Figure 91 Case 1, Millmerran contingency: line active power flows

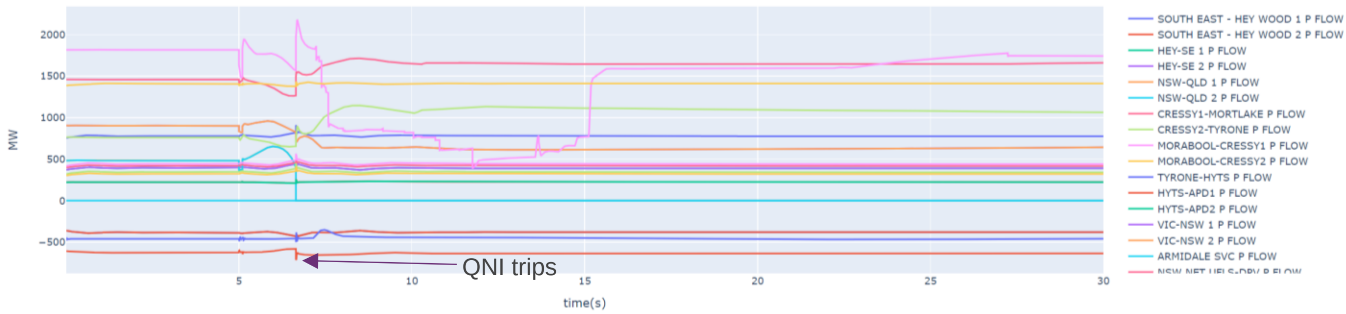


Figure 92 Case 1, Millmerran contingency: system bus voltages

A7. Draft 2023 GPSRR report feedback

AEMO sought submissions on the draft 2023 GPSRR report during a public consultation between 23 May 2023 and 8 June 2023.

AEMO received written submissions from the Clean Energy Council (CEC), CS Energy and Transgrid. The CS Energy and Transgrid submissions can be found on AEMO's website[45].

On 1 June 2023, AEMO held an open question-and-answer session with all interested parties, at which attendees were invited to ask questions and provide any feedback in relation to the 2023 GPSRR.

The following sections include summaries of the comments or questions from the submissions and question-and-answer session, including from the CEC, together with AEMO's responses, where relevant.

AEMO thanks all stakeholders who engaged with the 2023 GPSRR for their contributions to shaping the review and finalising this report.

A7.1 Clean Energy Council submission

Summary of CEC comments

The CEC's submission focused on the recommendation to review the protected events and reclassification frameworks. The CEC provided the following observations and suggestions on the framework:

- The current protected event framework is likely to be overly onerous and no longer fit for purpose, and the CEC would support the development of a rule change to see whether it can be simplified.
- The policy intent behind the framework is to provide some transparency as to what actions will be taken, and how the market will be impacted to manage significant risks. For condition dependent contingencies, the reclassification framework is largely appropriate. Where there is the need for significant capital investment and/or more material and sustained operational intervention in the market, then the protected event framework provides this needed transparency.
- For the protected events framework to function effectively, it must be operable and applicable by AEMO. The CEC would welcome a review of the framework to explore options to retain the fundamental value of transparency, while ensuring that AEMO does not face overly onerous burdens when proposing a protected event to the Reliability Panel.
- The CEC is happy to facilitate engagement with its own power system security working group for further insights and industry perspective.

AEMO response

AEMO thanks the CEC for its submission and will continue to engage with the relevant industry bodies, including the CEC, as part of its review of the protected event framework, which is planned to be completed by Q4 2023.

[45] See https://aemo.com.au/en/consultations/current-and-closed-consultations/draft-2023-gpsrr-report-consultation.

A7.2 CS Energy submission

Summary of CS Energy comments

CS Energy commended AEMO on the quality and detail of its work in both preparing the Draft 2023 GPSRR report and engaging with stakeholders, and made several observations and suggestions on AEMO's approach, recommendations and related matters.

CS Energy comment

CS Energy noted the number of references in the draft report to the Power System Security Guidelines[46] (SO_OP_3715), and considered this a critically important document to give operational effect to the analysis and recommendations in the 2023 GPSRR report. CS Energy acknowledged AEMO's endeavours to increase industry exposure to this document, but proposed that AEMO also table any major changes to SO_OP_3715 at the AEMO Fortnightly Operational Industry Update meetings.

AEMO response

The Power System Security Guidelines (SO_OP_3715) form part of the power system operating procedures and describe how AEMO seeks to operate the power system within the technical envelope and meet its power system security responsibilities generally. AEMO will also continue to provide detailed information on risk management measures in the GPSRR. AEMO has generally adopted the practice of highlighting material operational changes and updates at its Fortnightly Operational Industry Update meetings, to bring them to the attention of a wider audience. AEMO notes CS Energy's suggestion to include major updates to the Power System Security Guidelines in the briefings, and intends to do so.

CS Energy comment

In its submission on the 2023 GPSRR approach[47], CS Energy supported the application of the 2022 ISP *Step Change* scenario to assess future power system risks. Following the release of the AEMO 2022 ISP, CS Energy now considers the application of the 2022 ISP *Progressive Change* scenario as appropriate to assess future power system risks as it is driven by modelling plausible outcomes in the Australian economy.

AEMO response

As detailed in Section 4 and Appendix A3, for the 2023 GPSRR future studies, AEMO applied the ISP scenario that was identified as being most likely by energy industry stakeholders in the 2022 ISP. AEMO expects to do the same for future GPSRRs. Therefore, it is anticipated that if the ISP identifies a different most likely scenario, the next GPSRR will apply different assumptions for future studies.

CS Energy comment

CS Energy agreed with Recommendations 1 to 7 in the draft report, with a number of additional observations including:

[46] At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf?la=en.

[47] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/general-power-system-risk-review-approach-consultation/cs-energy.pdf?la=en.

- Noting the coordination challenge of multiple RAS to respond to the Moorabool contingency events for Recommendation 3.
- Reiterating the importance of including and detailing any state jurisdiction emergency reserve and/or system security contingency plans arising from Recommendation 4.
- Requesting AEMO and NSPs provide an opportunity for Participants to understand any required changes in operational capability and systems for Recommendation 5, in appropriate forums.
- Encouraging AEMO to confirm regular integrity testing and a compliance regime for RAS for Recommendation 6.

AEMO response

- Consistent with Appendix A2, AEMO intends to continue to track and report on recommendations from past GPSRR and PSFRR reports. This will include a summary of any contingency plans that are created in line with Recommendation 4.
- Regarding Recommendation 5, AEMO is committed to working with NSPs and industry stakeholders, including Participants, as part of managing risks associated with future operational capability.

CS Energy comment

Regarding Recommendation 8 (generator over frequency protection co-ordination strategy), CS Energy reiterated its view of the potential benefits provided by wide band frequency response (WBFR), that are arguably immediately deliverable and may reduce the time AEMO needs to allocate to the development of OFGS. CS Energy provided an extract of its submission to the AEMO PSFRR stage 1 consultation[48] on the arguments supporting WBFR.

AEMO response

See comments in Section A7.4 below.

CS Energy comment

CS Energy reserved its position on Recommendation 9 (review of the protected events framework) pending further details, and referred AEMO to its position on protected events in its submission to the PSFRR stage 1 consultation[49]. CS Energy sought appropriate balance in the level of scrutiny and transparency in the management of power system security under the reclassification framework.

AEMO response

As stated above, AEMO will continue to engage with the relevant industry bodies as part of its review of the protected event framework, which is planned to be completed by Q4 2023.

[48] https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-1/cs-energy-submission-on-draft-report.pdf?la=en.

[49] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-1/cs-energy-submission-on-draft-report.pdf?la=en.

A7.3 Transgrid submission

Summary of Transgrid comments

Transgrid supported all recommendations put forward in the draft report and made the following observations and suggestions:

- As the NEM transitions to greater renewable penetration and we experience greater climate extremes, it is vital that critical system risks are identified and mitigated to minimise disruptions to the network.
- Given the seriousness of the priority risks assessed by AEMO, Transgrid considers it critical that AEMO's recommendations are implemented in a timely way, along with logical subsequent actions. This should include providing clear funding pathways and defining roles and responsibilities for projects so that they can be delivered efficiently and in the long-term interests of energy consumers.
- Transgrid has begun discussions for mitigation of identified QNI instability risk under recommendations 2 and 3 in conjunction with AEMO and Powerlink.
- Transgrid supports the development of jurisdictional emergency reserve and system security contingency plans, which can be implemented at short notice if required, as a prudent recommendation that will help ensure supply adequacy and power system security for customers in the NEM. Transgrid would support joint efforts to study the events and development plans in New South Wales to progress this recommendation.
- In relation to the recommendation that TNSPs identify any operational capability gaps in the context of the transforming power system and changing risk profile of the NEM, Transgrid noted the importance of TNSPs and AEMO working together to define the appropriate solutions to these gaps and find a suitable pathway to obtain funding to enable them to proceed in a timely way, which is difficult under the current framework. Transgrid welcomed AEMO's involvement to play a key role in facilitating these crucial projects to proceed.
- Transgrid supported Recommendation 7 that, in line with the requirements of NER S5.1.8, TNSPs continue to consider non-credible contingency events which could adversely impact the stability of the power system. In Transgrid's experience, it is very difficult to secure funding to implement projects for managing multiple contingency events as outlined in NER S5.1.8. Where AEMO considers these risks to be unacceptable, an alternative project justification and funding pathway may be required.
- Beyond the priority risks identified in the draft 2023 GRSRR, Transgrid also encouraged further discussions to investigate the feasibility of undertaking preventative measures through the NEM dispatching system for the considered contingencies. These measures can potentially involve integration of multiple systems such as weather monitoring, on-line small-signal analysis, SCADA, and other relevant platforms. In this investigation, it will be important to leverage non-conventional tools such as artificial intelligence and adaptive controllers in addition to conventional tools while ensuring the cost of electricity for the market users remains unaffected.
- Transgrid said it is also considering resilience risks that are likely to emerge as the power system evolves with the development and connection of new very large REZs and major new transmission infrastructure. Transgrid observed that the size of credible contingencies will become much larger, and new (non-credible contingency) vulnerabilities will emerge on the network. At this scale, failures have the potential to lead to cascading outages, with system-wide impacts. To address these challenges, Transgrid considered it prudent to consider 'N-1 Secure' planning criteria for new major projects and connections, and placing an upper limit on the generation/network capacity that may be connected to a single point (as has been considered and implemented in other jurisdictions globally).

AEMO response

- AEMO is committed to actively working with industry stakeholders and engaging with market bodies as appropriate to inform efficient design and facilitate the timely implementation of GPSRR recommendations.
- Consistent with Recommendation 7, AEMO welcomes Transgrid's advice on future power system risks associated with new REZs and transmission augmentations and will continue to consider this in future GPSRRs.
- AEMO will also continue to evaluate a range of mitigation measures for the identified risks in future GPSRRs, including those highlighted in Transgrid's submission.

A7.4 2023 GPSRR question and answer session

A summary of the key questions raised during the 1 June 2023 session is provided below with AEMO responses.

Question

Why has Wide Band Frequency Response not been considered in addition to OFGS?

AEMO response

- Generator governor models used in GPSRR and previous PSFRR studies are intended to provide an indication of actual frequency performance, however it should be noted that there are a number of uncertainties in the modelling. For example, assumptions regarding the rate of response and the duration that a response is sustained depend on the characteristics of the plant and accuracy of models (or generic models used to represent plant performance where no specific model is available), including as a result of any unmodelled variations from the mandatory PFR requirements.
- To adequately assess other governor response characteristics, detailed modelling information is needed from Registered Participants representing actual plant performance, as AEMO understands that plant performance for a wide deadband response could vary widely across the fleet and be significantly different to PFR capability. This is challenging given legacy model issues and the inherent complexity of (synchronous) generator governor control systems.
- Additionally, localised large-scale BESS, such as those in South Australia, already provide a fast-acting proportional response for severe over-frequency events, depending on what capacity is available at the time of a disturbance.
- AEMO acknowledges the benefit of wide deadband frequency response to assist with extreme frequency events, as well as the need to explore how it interacts with the mandatory PFR requirements. AEMO will continue to consider wide-band frequency response as an option, in addition to the existing OFGS and over-frequency protection, if a specific need is identified. AEMO is committed to working with industry stakeholders through any future reviews.

Question

Enquiry about the non-credible event on 25 August 2018 following which EAPT operated to separate South Australia at Heywood.

AEMO response

As detailed in Appendix A2, AEMO recently completed several reviews of EAPT in response to its operation in 2018[50] – the EAPT scheme operated as designed, although the design did not cater for this event – and also as part of an impact assessment of recent network changes. As a result, setting changes have been implemented to reduce the risk of operation of EAPT for similar conditions, and recommendations made to further modify the scheme to improve its reliability. The reliability of the EAPT scheme will be greatly improved by changing its contingency detection from a performance-based approach (mode 3) to a performance and topology-based approach (mode 1)[51], which will mitigate unexpected operation due to power swings that may occur following different contingency events. This is in line with the *Final Report – Queensland and South Australia System Separation on 25 August 2018*[50] and the 2020 PSFRR recommendation to avoid mal-operation due to unexpected interaction with Interconnector Emergency Control Scheme (IECS)[52]. The EAPT upgrade project is scheduled to be completed by end of August 2023.

Question

Would it be possible to implement standing contingency plans for some of these risks, similar to what is implemented in the Power System Security Guidelines[53]?

AEMO response

The Power System Security Guidelines (SO_OP_3715) form part of the power system operating procedures and describe how AEMO seeks to operate the power system within the technical envelope and meet its power system security responsibilities generally, whereas NSP contingency plans contain further details for managing specific risks. AEMO will continue to provide detailed information on risk management measures in the GPSRR.

Question

Have we considered if the dynamics of PFR negatively affect the response in these contingencies that have been studied? Has AEMO done any studies on the full capacity of PFR compared to more onerous

[50] At https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2018/qld---sa-separation-25-august-2018-incident-report.pdf?la=en&hash=49B5296CF683E6748DD8D05E012E901C.

[51] The EAPT has three operational modes: mode 1 – topology and performance-based, mode 2 – topology-based, mode 3 – performance-based. See Appendix Section A3.2.8 for more details on the EAPT scheme.

[52] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-2/2020-psfrr-stage-2-final-report.pdf?la=en.

[53] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf?la=en.

requirements? Are there any studies that have been done on whether changes to dynamic response could make PFR more/less effective?

AEMO response

The governance arrangements in the NER, and final rule for PFR incentive arrangements, allow for the sensitivity of the PFR requirement to be adjusted through the review of the primary frequency control band (PFCB) by the Reliability Panel. On 6 April 2023, the Reliability Panel published the final determination and revised standard for its review of the FOS, including the PFCB[54]. The revised FOS maintains the current allowable ranges for frequency during normal operation through the normal operating frequency band (NOFB) and the normal operating frequency excursion band (NOFEB). It also confirms the PFCB as 49.985-50.015 Hz, consistent with the current setting in the NER. This element of the Reliability Panel's determination was supported by advice from AEMO and the results of power system modelling undertaken by GHD which shows that provision of narrow band PFR by the bulk of the generation fleet delivers effective control of system frequency, increased power system resilience and reduced aggregate costs for frequency control.

The Panel recommended a subsequent review of the settings in the FOS for normal operation at a future date. This future review could account for further learnings from AEMO's reporting on aggregate frequency responsiveness, which commenced in Q3 2022, and (from mid-2025) operational experience with the new frequency performance payments[55].

Question

Regarding modelling PFR for the GPSRR, how did AEMO manage that there is no obligation to provide headroom/footroom?

AEMO response

For the 2023 GPSRR historical studies, AEMO used historical dispatches from OPDMS. For future studies, the 2022 ISP forecasting methodology, set out in the 2021 ISP Methodology[56], was applied to forecast future network dispatch conditions. The PSS®E generator models used also limit power outputs to reflect each generator's minimum and maximum capacity. The modelling approach is further detailed in Section 4 and Appendix A3.

Question

In the 2023 GPSRR Approach Paper, Table 8, historical risk 3 (Mount Piper contingency), were these trips related to lightning?

AEMO response

The 5A3 and 5A5 500 kV lines in New South Wales have previously tripped due to lightning and bushfires. As detailed in Section 4, the 5A3 and 5A5 lines are currently on the vulnerable lines list[57], meaning that they will be reclassified as a credible contingency event during a lightning storm if a cloud to ground lightning strike is detected within a specified distance of these lines. Prior to October 2022, the end date for the 'probable' state of

[54] See https://www.aemc.gov.au/sites/default/files/2023-04/REL0084%20-%20Final%20Determination.pdf.

[55] See https://www.aemc.gov.au/sites/default/files/2023-04/REL0084%20-%20Final%20Determination.pdf.

[56] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en.

[57] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/power-system-operating-procedures/list-of-vulnerable-transmission-lines.

these lines on the vulnerable lines list was 17 February 2023. On 20 October 2022, a lightning strike caused the simultaneous trip of 5A3 and 5A5, which resulted in their status returning to proven until 20 October 2027.

Question

Regarding Remedial Action Schemes, there is an increasing number of them. How often is an integrity check of these schemes completed?

AEMO response

There are now additional obligations for NSPs to review protection schemes through their annual planning process under NER clause 5.12.1(b)(7) and 5.13.1(d)(6). AEMO expects that there will be more focus on this area in the upcoming NSP annual planning reports. The risks associated with control/protection system interaction are further discussed in Section 6.9 of the 2023 GPSRR.

Question

In the studies that have been conducted, how much of a safety margin is used?

AEMO response

AEMO acknowledges that severe frequency events can be difficult to model. Studies undertaken as part of the GPSRR are intended to identify power system risks and the need for associated mitigation measures. For example, as detailed in Appendix A4, the purpose of the 2023 GPSRR studies of risk 4 (non-credible events that could lead to QNI instability) was to identify contingencies across the NEM that could lead to QNI instability, rather than to design an SPS to mitigate the risk. Due to this, safety margins are applied such that studies are appropriately evaluating power system risk and provide insight into areas that could lead to cascading failures or supply disruptions. These safety margins are incorporated through the assumptions applied for the study approach, which, for the 2023 GPSRR, are detailed in Section 4 and Appendix A3. The detail of the studies completed inform the GPSRR recommendations.

Question

Any comments on how protected events are treated like credible contingencies, but are considered differently in the FOS?

AEMO response

The FOS allows a greater deviation in power system frequency for protected events, and otherwise the power system security requirements are largely the same as for credible contingency events. This principle can present issues for the effective application of the protected events framework, as discussed in Section 7.4. However, the controls implemented for the existing South Australia protected event are to avoid South Australian separation for a 500 MW loss of generation within South Australia (this is further detailed in Section 7.1). This 500 MW generation loss is lower than the normal maximum generation contingency size within the NEM so will be managed through normal FCAS procurement. As the controls implemented aim to rebalance supply demand through operation of the System Integrity Protection Scheme (SIPS) as well as provide adequate headroom on the Heywood interconnector, this aims to avoid South Australian separation. Therefore, the wider protected event frequency range allowed for in the FOS is not relevant for the existing South Australian protected event.