2023 General Power System Risk Review Report

July 2023

Final Report

A report for the National Electricity Market

Important notice

Purpose

AEMO has prepared this final 2023 General Power System Risk Review report in accordance with clause 5.20A.3 of the National Electricity Rules.

This publication is generally based on information available to AEMO at 1 July 2023 unless otherwise indicated.

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Version control

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

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Executive summary

AEMO undertakes the general power system risk review (GPSRR) annually for the National Electricity Market (NEM) in consultation with network service providers (NSPs), in accordance with the National Electricity Rules (NER). This 2023 review is the first GPSRR, which replaces the former biennial power system frequency risk review (PSFRR).

The purpose of the GPSRR is to review a prioritised set of power system risks, comprising events or conditions that, alone or in combination, would likely lead to cascading outages or major supply disruptions. For each priority risk, the GPSRR assesses the adequacy of current risk management arrangements and (where appropriate) options for future management. This GPSRR includes updates on key findings and recommendations from the previous PSFRRs[1].

The NEM is supporting a once-in-a-century transformation in the way society considers and consumes energy. Associated with this transformation are a range of factors that influence the resilience of the NEM, such as fewer synchronous generators, increased power transfers through major transmission corridors and concentrated provision of contingency frequency control ancillary services (FCAS) in some regions. The increase in connection of inverter-based resources (IBR) and distributed energy resources (DER) also poses challenges in maintaining grid stability, voltage and frequency control while managing evolving weather-related risks.

These significant changes to the power system also require an increase in the number and complexity of special protection schemes (SPSs). While SPSs can enhance the resilience of the system, they also have the potential to create additional risks in relation to maloperation of schemes.

The GPSRR is a central body of work that explores the risks and consequences of non-credible contingencies as well as other system events and conditions that could lead to cascading outages or major supply disruptions.

The GPSRR considers how these risks evolve over a five-year planning horizon, taking into account potential changes in power system operation over that period. The GPSRR builds on and complements other work undertaken by AEMO, such as the *Integrated System Plan* (ISP), *Engineering Roadmap to 100% Renewables*, and AEMO risk management initiatives.

Through consultation with NSPs, review of previously identified risks and recent power system incidents, AEMO identified four priority risks for consideration in the 2023 GPSRR:

- Risk 1 (Wagga contingency): Loss of major 330 kilovolt (kV) lines in south west New South Wales (Wagga – Jindera 330 kV line 62 and Wagga – Darlington Point 330 kV line 63).
- Risk 2 (Tamworth contingency): Trip of Tamworth double 330 kV bus (Sections 1 and 3), a critical 330 kV substation south of the Queensland – New South Wales Interconnector (QNI), due to circuit breaker (CB) failure of bus coupler CB 5102.

[1] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

- Risk 3 (Mount Piper contingency): Loss of Bayswater – Mount Piper (5A3) and Mount Piper – Wollar (5A5) major 500 kV lines in the western New South Wales outer ring[2].
- Risk 4 (QNI instability): Assessment of a selection of non-credible events that could lead to QNI instability, considering the increase in QNI power transfer limit planned as part of the QNI Minor upgrade.

The non-credible contingencies comprising Risks 1 to 3 were studied against historical power system operating conditions, as relevant to the timing of potential solutions.

Risk 4 was studied against future operating conditions for financial year 2027-28 forecast operating conditions. The 2027-28 future operating conditions were derived using the 2022 ISP *Step Change* scenario and contained the associated forecasted network augmentations and generation retirements.

Historical studies

Studies undertaken for Risk 1 (Wagga contingency) found that the non-credible loss of the 62 and 63 330 kV lines can result in the operation of the Emergency Alcoa Portland Tripping (EAPT) scheme when in the performance-based mode (mode 3)[3]. This result demonstrates the advantages of changing the EAPT scheme to a topology and performance-based scheme (mode 1), which will prevent unexpected operation due to power swings that may occur following different contingency events. As detailed in Appendix A2, this action has been since been completed consistent with a recommendation in the 2020 PSFRR. The study of Risk 1 did not identify the need for any other remedial actions.

Studies undertaken for Risk 2 (Tamworth contingency) showed that a Tamworth 330 kV bus fault and subsequent CB failure of bus coupler CB 5102 can cause QNI to become unstable. The failure/incorrect operation of CB 5102 is the key event of this incident (causing two busbars to trip and increasing the impact of this event). After this contingency, due to the configuration of the 330 kV network at Tamworth, Queensland remains synchronously connected to the rest of the mainland NEM via the remaining 132 kV network in northern New South Wales. The impedance of the connection between Queensland and the rest of the mainland NEM is therefore greatly increased. This increased impedance was found to lead to instability on QNI and the synchronous separation/islanding of the Queensland region with the potential for subsequent power system events to occur[4]. Therefore, any action that can be taken to ensure the correct operation of CB 5102 will reduce the likelihood of this incident occurring. Transgrid has advised AEMO that CB 5102 was commissioned in 2002 and has a good condition history and that there are no population type issues identified for this CB family. Given CB 5102's good condition, AEMO recommends that Transgrid continues to maintain CB 5102 with consideration to the criticality and potential impact of its failure.

Additionally, the future actionable ISP New England Renewable Energy Zone (REZ) 500 kV network augmentations (which have an optimal delivery date of July 2027) could reduce the impact of this contingency, as following fault clearance at Tamworth, Queensland will remain synchronously connected to the NEM via a new double-circuit 500 kV line from the locality of Armidale South to Bayswater via east of Tamworth[5]. Given this ISP actionable augmentation, AEMO has concluded that existing risk mitigation measures are sufficient to manage this risk.

[2] Initial studies evaluating Risk 3 (Mount Piper contingency) did not identify any issues, therefore there are no associated recommendations for this event.

[3] 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.

[4] By inference, as observed during actual power system events.

[5] See https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en.

Recommendation 1

Based on findings in relation to busbar faults at Tamworth (Risk 2), AEMO recommends that:

a) Transgrid continues to maintain circuit breaker (CB) 5102 and associated equipment with consideration to the criticality and potential impact of its failure.

b) Transgrid maintains the 132 kV system distance protection systems near Tamworth and associated equipment with consideration to the criticality and potential impact of its failure.

Refer to Section 5.1.2 for further details.

Studies undertaken for Risk 3 (Mount Piper contingency) confirmed AEMO's current position that no constraints need to be invoked when this contingency is reclassified as credible. The 5A3 and 5A5 500 kV lines are categorised as vulnerable transmission lines under the lightning reclassification criteria, and had the category changed from probable to proven during the period of analysis for the 2023 GPSRR.

Future studies

Studies undertaken for Risk 4 (QNI instability) as part of the 2022 PSFRR and 2023 GPSRR identified an existing and increasing risk of QNI instability following a range of non-credible contingencies across the mainland NEM, with the potential for cascading events to occur.

Consistent with what was observed in the 2022 PSFRR, studies by AEMO highlight that for scenarios where loss of the Moorabool Terminal Station (MLTS) lines[6] could result in the South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS) actions not being able to prevent a large power swing on Project Energy Connect (PEC), this could lead to the tripping of PEC and the synchronous separation of South Australia, as well as the tripping of QNI and the synchronous separation of Queensland. Therefore, the results show that Moorabool separation can possibly cause loss of stability on QNI, which could be exacerbated by the actions of existing SPSs within Victoria and the SAIT RAS due to the total generation disconnected.

Recommendation 2

Given the potentially significant impact Risk 4 could have on the NEM, AEMO recommends that Powerlink and Transgrid investigate, design and implement a special protection scheme (SPS) under NER S5.1.8 to mitigate the risk of QNI instability and synchronous separation of Queensland following a range of non-credible contingencies. If a scheme is found viable, AEMO recommends this scheme be commissioned as soon as possible, and no later than June 2025. Refer to Section 5.2 for further details.

Recommendation 3

Given the potential for Moorabool contingency events to result in separation of the mainland NEM into four islanded areas – Queensland, South Australia (separated at Heywood following EAPT operation), the network between Heywood and Moorabool (not a viable island) and the rest of New South Wales and Victoria – AEMO recommends that AEMO, AEMO Victorian Planning (AVP), ElectraNet and Transgrid continue collaborating as part of the PEC System Integration Steering Committee (SISC) to ensure that the SAIT RAS operates

[6] MLTS – Mortlake Power Station and MLTS – Haunted Gully Terminal Station (HGTS) 500 kV lines.

effectively in conjunction with existing NEM system protection and generation tripping schemes (see Appendix A3.2 for relevant schemes), as well as any future QNI SPS and other protection schemes. Refer to Section 5.2 for further details.

Review of risk management measures

The GPSRR considers high impact power system events that pose significant risks and may lead to cascading outages or major supply disruptions. Significant events that have occurred since the 2022 PSFRR include:

- June 2022, the NEM market suspension and energy/capacity shortage.
- October 2022, Tasmanian tower failure and trip of Liapootah – Palmerston 220 kV lines.
- November 2022, South Australian tower failure and trip of South East – Tailem Bend 275 kV lines.
- March 2023, market suspension due to loss of supervisory control and data acquisition (SCADA) systems in New South Wales.
- April 2023, market suspension due to loss of SCADA systems in Victoria.
- April 2023, Western Australian solar eclipse and associated significant change in distributed photovoltaics (DPV) output.

In addition to the evaluation of priority high impact events, the GPSRR also provides an overview of risk mitigation measures encompassing Emergency Frequency Control Schemes (EFCSs), operational capabilities and other emerging risks in the context of an evolving power system. Based on the review of recent events, internal risk assessments and the current measures in place, AEMO makes the following recommendations.

Recommendation 4

AEMO recommends that each participating jurisdiction develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risks. These plans should be for an appropriate level of capacity for the region, and encompass details of the generation technology, connection point and connection arrangement, fuel supply adequacy, environmental considerations, construction, and commissioning timelines as well as equipment availability and lead times. Refer to Section 6.5 for further details.

Recommendation 5

In the context of the transforming power system and changing risk profile of the NEM, AEMO recommends that all NSPs, where not already doing so, evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training. Refer to Section 6.6 for further details.

Recommendation 6

AEMO recommends that, in line with the requirements of NER S5.1.8, NSPs continue to consider non-credible contingency events which could adversely impact the stability of the power system. In considering these non-credible contingency events, NSPs should identify and implement suitable controls to mitigate any identified risks. It is anticipated that these controls may involve the implementation of new remedial action schemes (RASs), in which case NSPs should consult with AEMO and refer to the RAS Guidelines developed by AEMO and NSPs[7]. Refer to Section 6.9.6 for further details.

Recommendation 7

Transgrid is investigating the risk and consequence of non-credible contingencies on the 330 kV lines supplying Sydney, Newcastle and Wollongong following potential Eraring Power Station closure. AEMO recommends that Transgrid share its investigation findings with AEMO for consideration in future GPSRRs. Refer to Section 6.9.8 for further details.

Recommendation 8

AEMO to finalise the development of an updated strategy for the overall co-ordination of generator over frequency protection settings. Refer to Section 6.1 for further details.

Review of protected events

Existing SA destructive winds protected event

In reviewing the existing protected event, and in response to 2022 PSFRR recommendation 8.c), AEMO concluded that appropriate constraints for the network topology post PEC Stage 1 can be implemented under the updated contingency reclassification criteria[8]. Furthermore, implementation of an SPS to mitigate risk of non-credible loss of PEC can be made efficiently under NER S5.1.8. On 11 April 2023, AEMO submitted a request to the Reliability Panel to revoke the protected event prior to 1 October 2023[9]. The Reliability Panel is currently reviewing this request.

QNI instability protected event

Following 2022 PSFRR recommendation 4.b), AEMO assessed whether it is economic to apply ex-post measures under a protected event to manage QNI instability. All mitigating options assessed produce negative net market benefits. As such, AEMO has determined that the most appropriate action is for Powerlink and Transgrid to develop an SPS to mitigate potential loss of QNI following large non-credible contingency events (see Recommendation 2 above).

SA separation protected event

The 2020 PSFRR[10] proposed that AEMO would explore recommending the declaration of a protected event to manage the non-credible synchronous separation of South Australia with the rest of the NEM. AEMO's analysis identified a number of measures to reduce risk to be implemented in the period prior to full commissioning of PEC Stage 2. All the recommended measures can be implemented without a protected event. Declaration of a protected event also has a number of flow-on implications, which require extensive further study and may not be economically feasible to manage at this time. For these reasons, following extensive analysis and stakeholder

[7] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/publication-of-remedial-action-scheme-guidelines/further-information/remedial-action-scheme-guidelines-consultation.pdf?la=en.

[8] See https://www.aemc.gov.au/sites/default/files/2022-03/Indistinct%20Events%20Final%20Determination.pdf. See https://www.aemc.gov.au/sites/default/files/2022-03/Indistinct%20Events%20Final%20Determination.pdf.

[9] Prior to the expected date of synchronous electrical connection of South Australia to New South Wales via PEC Stage 1.

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

engagement, 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.

Possible protected event framework rule change request

As discussed in the 2020 PSFRR and Section 7.4 of this report, there are a number of challenges and limitations with the current protected event framework. In summary:

- The NER requires that any protected event is treated identical to a credible contingency for many aspects of power system security. This requirement can have undesirable outcomes, including:
  - Greatly increased study and system limits assessment complexity to investigate each dimension of a particular non-credible contingency. This makes an already long process for assessing possible new protected events slower, and highly onerous.
  - The lack of flexibility in the framework may mean that prudent pre-incident/event action to address known frequency risks cannot be taken at all, if the costs of additionally managing the protected event to the same standard as a credible event are not justified on a cost/benefit assessment.
- Certain condition-dependent risks that could only previously be managed under the protected event framework can now be managed effectively under the indistinct events framework. The indistinct events framework allows AEMO to adjust the actions taken to manage an identified risk (to account for network changes or changes to the risk profile) promptly.

Therefore, AEMO considers there is benefit in reviewing the protected event framework to ensure that the framework is fit for purpose considering the implications of declaring protected events.

Recommendation 9

AEMO to review the protected event framework by Q4 2023. As part of this review, AEMO will consider the submission of a rule change proposal to enhance the protected event framework. Refer to Section 7.4 for further details.

Industry consultation

AEMO sought submissions from all persons interested in the 2023 GPSRR during a public consultation period between 23 May 2023 and 8 June 2023.

During this consultation, AEMO received three written submissions on the draft 2023 GPSRR report, from the Clean Energy Council (CEC), CS Energy and Transgrid. AEMO thanks the CEC, CS Energy and Transgrid for their submissions. The CS Energy and Transgrid submissions can be found on AEMO's website[11], and a summary of feedback, including from the CEC, and AEMO's responses can be found in Appendix A7.

On 1 June 2023, AEMO held a question-and-answer session for industry stakeholders interested in the 2023 GPSRR. During the session AEMO invited attendees to ask questions and provide feedback in relation to the 2023 GPSRR. A summary of the substantive questions and feedback received in this session and AEMO's responses is also included in Appendix A7.

[11] At https://aemo.com.au/consultations/current-and-closed-consultations/draft-2023-gpsrr-report-consultation.

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Abbreviations

Abbreviation	Term	Abbreviation	Term
AC	alternating current	NEM	National Electricity Market
ACCC	Australian Competition and Consumer Commission	NER	National Electricity Rules (NER followed by a number indicates that numbered rule or clause of the NER)
AEMC	Australian Energy Market Commission	NGR	National Gas Rules
AER	Australian Energy Regulator	NOFB	normal operating frequency band
AMI	advanced metering infrastructure	NSCAS	network support and control ancillary services
APC	administered price cap	NSP	network service provider
APD	Alcoa Portland	NSW	New South Wales
ARENA	Australian Renewable Energy Agency	OCGT	open cycle gas turbine
ASEFS2	Australian Solar Energy Forecasting System Phase 2	OFGS	over frequency generation shedding
AUFLS2	Adaptive Under Frequency Load Shedding Scheme 2	OFTB	operating frequency tolerance band
AVP	AEMO Victorian Planning	OPDMS	Operations and Planning Data Management System
BESS	battery energy storage system/s	OT	operational technology
CB	circuit breaker	OTR	Operations Technology Roadmap
CCGT	combined cycle gas turbine	PACR	Project Assessment Conclusions Report
CER	consumer energy resources	PAREP	Port Augusta Renewable Energy Park
CMLD	composite load model	PASA	projected assessment of system adequacy
CPI	consumer price index	PD	pre-dispatch
CPT	cumulative price threshold	PEC	Project EnergyConnect
CQ	Central Queensland	PFC	primary frequency control
CT	current transformer	PFR	primary frequency response
DER	distributed energy resources	PJ	petajoules
DNSP	distribution network service provider	PLL	phase locked loop
DPV	distributed photovoltaics	PSCAD™	Power System Computer Aided Design
DWGM	declared wholesale gas market	PSFRR	Power System Frequency Risk Review
EAPT	Emergency Alcoa-Portland Potline Tripping	PSS®E	Power System Simulation for Engineering
EFCS	emergency frequency control scheme	PVNSG	photovoltaic non-scheduled generators
EFETL	extreme frequency excursion tolerance limit	QLD	Queensland
EMT	electromagnetic transient	QNI	Queensland to New South Wales Interconnector
ESOO	Electricity Statement of Opportunities	QREZ	Queensland Renewable Energy Zone
EUFR	emergency under frequency response	RAS	remedial action scheme
FCAS	frequency control ancillary services	RERT	reliability and emergency reserve trader
FFR	fast frequency response	REZ	renewable energy zone
FOS	Frequency Operating Standard	RMS	root mean squared
FRT	fault ride-through	RoCoF	rate of change of frequency
FY	financial year	RTTS	Robertstown Terminal Station
GSOO	Gas Statement of Opportunities	s	second/s

Abbreviation	Term	Abbreviation	Term
GPSRR	General Power System Risk Review	SA	South Australia
GW	gigawatt/s	SAIT RAS	South Australia Interconnector Trip Remedial Action Scheme
HGTS	Haunted Gully Terminal Station	SCADA	supervisory control and data acquisition
HIC	Heywood interconnector	SCR	short circuit ratio
HV	high voltage	SESS	South East Switching Station
HVDC	high voltage direct current	SIPS	system integrity protection scheme
HYTS	Heywood Terminal Station	SISC	System Integration Steering Committee
Hz	Hertz	SPS	special protection scheme/s
Hz/s	Hertz per second	SQ	Southern Queensland
IASR	Inputs Assumptions and Scenarios Report	SRMC	short run marginal cost
IBR	inverter-based resources	SSIAG	System Strength Impact Assessment Guidelines
ICS	industrial control system	SSRM	System Strength Requirements Methodology
IECS	Interconnector Emergency Control Scheme	SSSP	System Strength Service Provider
IPFRR	Interim Primary Frequency Response Requirements	ST	short term
ISP	*Integrated System Plan*	STTM	short term trading market
JSSC	Jurisdictional System Security Coordinator	SVC	static volt-ampere reactive compensator
km	kilometre/s	SWIS	South West Interconnected System
kV	kilovolt/s	TAPR	Transmission Annual Planning Report
kW	kilowatt/s	TAS	Tasmania
kWh	kilowatt-hour/s	TNSP	transmission network service provider
LFAS	load-following ancillary services	TTHL	trip to house load
line 11	Dapto – Sydney South 330 kV transmission line	TUoS	Transmission Use of System
line 17	Avon – Macarthur 330 kV transmission line	UFLS	under frequency load shedding
line 39	Bannaby – Sydney West 330 kV transmission line	VCR	value of customer reliability
line 51	Wagga – Lower Tumut 330 kV transmission line	VEEC	Victorian Electricity Emergency Committee
line 62	Wagga – Jindera 330 kV transmission line	VIC	Victoria
line 63	Wagga – Darlington Point 330 kV transmission line	VGPR	Victorian Gas Planning Report
line 79	Wollar – Wellington 330 kV transmission line	VNI	Victoria to New South Wales Interconnector
line 81	Liddell – Newcastle 330 kV transmission line	VRE	variable renewable energy
line 82	Liddell – Tomago 330 kV transmission line	VSC	voltage-sourced converter
line 969	Tamworth 330 – Gunnedah 132 kV transmission line	WAMPAC	wide area monitoring protection and control
line 9U4	Inverell – White Rock 132 kV transmission line	WAPS	wide area protection scheme
line 9UG	White Rock – Glen Innes 132 kV transmission line	WEM	Wholesale Electricity Market
LCC	line commutated converter	WF	wind farm
LOR	lack of reserve	X2	Buronga – Broken Hill 220 kV transmission line
MLTS	Moorabool Terminal Station	X3	Buronga – Balranald 220 kV transmission line
MOPS	Mortlake Power Station	X5	Balranald – Darlington Point 220 kV transmission line
ms	millisecond/s	0X1	Buronga – Red Cliffs 220 kV transmission line

Abbreviation	Term	Abbreviation	Term
MT	medium-term	1P	single-phase
MV	medium voltage	3P	three-phase
MVA	megavolt-ampere/s	5A3	Bayswater – Mt Piper 500 kV transmission line
MW	megawatt/s	5A5	Mount Piper – Wollar 500 kV transmission line
MWh	megawatt hour		
MWs	megawatt-second/s		

Key report terms

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
Satisfactory operating state	The power system is in a satisfactory operating state when: • Power system frequency is within the normal operating frequency band • Voltage magnitudes are within relevant limits • Current flows on all transmission lines are within equipment ratings • All other plant forming part of the power system is being operated within its ratings • The power system is being operated such that fault potential is within circuit breaker capabilities • The power system is considered stable
Secure operating state	The power system is defined to be in a secure operating state when: • The power system is in a satisfactory operating state • The power system will return to a satisfactory operating state following any credible contingency event
Credible contingency event, or credible contingency	A contingency event is considered credible when AEMO considers its occurrence to be reasonably possible in the surrounding circumstances including the technical envelope. Without limitation, examples of credible contingency events are likely to include: • the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating generating unit; or • the unexpected disconnection of one major item of transmission plant (such as transmission line, transformer or reactive plant) other than as a result of a three phase electrical fault anywhere on the power system.
Non-credible contingency event, or non-credible contingency	A contingency event other than a credible contingency event. Without limitation, examples of non-credible contingency events are likely to include: • three phase electrical faults on the power system; or • simultaneous disruptive events such as: – multiple generating unit failures; or – double circuit transmission line failure (such as may be caused by tower collapse).
Protected event	A non-credible contingency event that the Reliability Panel has declared to be a protected event under NER 8.8.4 after consultation on a request made by AEMO, where that declaration has not been revoked.

1 Introduction

1.1 Purpose

This is AEMO's final report on its 2023 General Power System Risk Review (GPSRR), undertaken under rule 5.20A of the National Electricity Rules (NER). This is the first GPSRR for the National Electricity Market (NEM), replacing the former biennial power system frequency risk review (PSFRR). AEMO will now undertake a GPSRR at least once a year, considering a prioritised set of risks comprising contingency events as well as other events and conditions that AEMO considers would be likely to lead to cascading outages or major supply disruptions.

The priority risks for the 2023 GPSRR and AEMO's assessment approach were determined through a process of initial consultation with network service providers (NSPs), followed by broader public consultation in late 2022[12].

This final report presents:

- The results of AEMO's assessment to date of the four priority risks detailed in Section 1.2, including a review of the current arrangements for management of those risks (see Section 4 and Section 5).
- Where required, technically and economically feasible options for the future management of those priority risks, and recommended options (see Section 5).
- AEMO's assessment of the current arrangements to manage the existing protected event in the NEM (see Section 7).
- A summary of the ongoing work to assess and identify required modifications to existing emergency frequency control schemes (see Section 6).

1.1.1 NER requirements related to the GPSRR

NER 5.20A sets out the scope of the GPSRR and the matters to be assessed and reported on. AEMO's findings and recommendations on these matters, where actioned, intersect with several other NER requirements and responsibilities, particularly, but not exclusively, in relation to emergency frequency control schemes (EFCSs) (primarily under frequency load shedding (UFLS)). Many of these rules apply independently of the GPSRR and its recommendations.

Table 1 lists other key NER obligations that are particularly relevant to managing the power system risks that may be covered by the GPSRR.

Table 1 NER requirements related to GPSRR

NER clause	Description
4.2.3A	Reclassification of continency events from non-credible to credible in abnormal conditions affecting the power system, as recently amended[A] to make clear provision for reclassification and appropriate management actions in conditions that may have a widespread impact, where it is not practical to identify the specific assets at risk.
4.3.1(k), (p1)	System security – AEMO's responsibilities that relate to, or are impacted by, the responses of EFCS.

[12] Finalised in AEMO's 2023 GPSRR Approach Paper, December 2022, Consultation material on the 2023 GPSRR approach, https://aemo.com.au/consultations/current-and-closed-consultations/general-power-system-risk-review-approach-consultation.

NER clause	Description
4.3.1(n), 4.3.2	System security – AEMO to provide information to facilitate resolution of risks outside AEMO's control; requirements for AEMO to develop EFCS settings schedules in consultation with NSPs and (as relevant), jurisdictional system security coordinators and generators.
4.3.4	NSPs to cooperate with AEMO to achieve power system security responsibilities, and specifically in relation to the design and implementation of EFCS and the provision of sufficient interruptible loads.
4.3.5, S5.3.10, S5.6 Part A (k)	Market Customer responsibilities for providing interruptible load from facilities with at least 10 megawatts (MW) peak demand.
5.12.1(b)(7) and 5.13.1(d)(6)	NSP review of interactions between emergency controls, emergency frequency controls, protection systems and control systems (published in its Transmission Annual Planning Report or Distribution Annual Planning Report).
5.14, 5.16, 5.17	Joint planning obligations where recommended investments involve more than one NSP, and the application of the regulatory investment test to investments other than protected event EFCS.
S5.1.8 (including reporting requirements under 5.12.2(c)(9))	NSP planning obligation to consider non-credible contingency events – such as busbar faults which result in tripping of several circuits, uncleared faults, double circuit faults and multiple contingencies – which could potentially endanger the stability of the power system. Where consequences are likely to involve severe disruption, NSP and Registered Participants must install, maintain and upgrade emergency controls in consultation with AEMO.
S5.1.10.1(a)	NSPs, in consultation with AEMO, to ensure that UFLS loads are sufficient to minimise or reduce the risk that frequency will exceed the extreme tolerance limits in the event of multiple contingency events.
S5.1.10.2	Distribution network service provider (DNSP) obligations to cooperate with transmission network service providers (TNSPs), provide and maintain UFLS facilities and apply settings as required.

A. National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule 2022. AEMC consultation material, https://aemc.gov.au/rule-changes/enhancing-operational-resilience-relation-indistinct-events.

1.1.2 GPSRR relationship with other reports

The GPSRR draws inputs from, and in turn informs and supports, a number of related reports and processes owned by AEMO and transmission network service providers (TNSPs). These include:

- AEMO's *Inputs, Assumptions and Scenarios Report* (IASR)[13], which presents a range of credible future scenarios representing possible policy settings and technology updates, and feeds into AEMO's planning publications.
- AEMO's *Integrated System Plan* (ISP)[14], a whole of system plan for the efficient development of the power system needs for a planning horizon of at least 20 years in the long-term interests of consumers of electricity.
- AEMO's System Security Reports[15], in which AEMO considers the need for any power system security and reliability services in the NEM over the coming five years as part of its obligations to assess system strength, inertia and network support and control ancillary services (NSCAS) requirements and shortfalls.
- AEMO's *Roadmap to 100% Renewables*[16], a technical base to inform industry prioritisation of steps necessary to securely, reliably and affordably transition. Further details are available in Section 1.6.
- AEMO's previous Power System Frequency Risk Reviews (PSFRRs)[17], the predecessor to this report which focused on frequency risks.

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

[14] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

[15] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[16] At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf.

[17] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

- TNSPs' Transmission Annual Planning Reports (TAPRs)[18].

1.2 Priority risks considered in the review

The risks studied in the 2023 GPSRR were identified through a prioritisation process in consultation with NSPs and other interested stakeholders, as well as by considering recent operational experience and power system incidents. More details on how AEMO assessed and categorised risk events can be found in the GPSRR approach paper[19]. AEMO identified four priority risks for consideration in the 2023 GPSRR:

- Risk 1 (Wagga contingency): Loss of major 330 kilovolt (kV) lines in south west New South Wales (Wagga – Jindera 330 kV line 62 and Wagga – Darlington Point 330 kV line 63).
- Risk 2 (Tamworth contingency): Trip of Tamworth double 330 kV bus (Sections 1 and 3), a critical 330 kV substation south of the Queensland – New South Wales Interconnector (QNI), due to circuit breaker (CB) failure of bus coupler CB 5102.
- Risk 3 (Mount Piper contingency): Loss of Bayswater – Mount Piper (5A3) and Mount Piper – Wollar (5A5) major 500 kV lines in the western New South Wales outer ring[20].
- Risk 4 (QNI instability): Assessment of a selection of non-credible events that could lead to QNI instability, considering the increase in QNI power transfer limit planned as part of the QNI Minor upgrade.

The non-credible contingencies comprising Risks 1 to 3 were studied against historical power system operating conditions, as relevant to the timing of potential solutions.

Risk 4 was studied against future operating conditions for financial year 2027-28 forecast operating conditions. The 2027-28 future operating conditions were derived using the 2022 ISP *Step Change* scenario and contained the associated forecasted network augmentations and generation retirements.

The study methodology for the priority risks has been further detailed in Section 4 and the results and observations are detailed in Section 5.

1.3 Acknowledgements

AEMO acknowledges the support of many stakeholders to facilitate and inform the 2023 GPSRR, in particular:

- NSPs in supporting the study inputs, identifying priority events, and providing review comments.
- Industry consultation forum participants for their observations and insights.
- GHD for its expert assistance in developing and benchmarking the future studies base case and completing select future studies.

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[18] 2022 Transgrid TAPR https://www.transgrid.com.au/tapr; 2022 Powerlink TAPR https://www.powerlink.com.au/reports/transmission-annual-planning-report-2022; 2022 ElectraNet TAPR https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/; 2022 TasNetworks TAPR https://www.tasnetworks.com.au/poles-and-wires/planning-and-upgrades/planning-our-network; 2022 AEMO Victorian TAPR https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

[19] At 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.

[20] Initial studies evaluating Risk 3 (Mount Piper contingency) did not identify any issues, therefore there are no associated recommendations for this event.

1.4 Stakeholder engagement

In developing the scope and progressing the 2023 GPSRR, AEMO consulted extensively with NSPs and industry on the approach, studies, and report. Consultation steps were:

- July to August 2022: AEMO engaged with all NSPs to assist in completing risk assessments and identifying the priority risks.
- August 2022: AEMO shared a preliminary draft 2023 GPSRR approach paper with all NSPs and Jurisdictional System Security Coordinators (JSSCs) for review.
- September 2022: AEMO published the 2023 GPSRR approach paper for industry consultation.
- October 2022: AEMO held an industry briefing session on the 2023 GPSRR approach paper.
- December 2022: AEMO published the final 2023 GPSRR approach paper[21] together with written submissions and consultation report[22].
- January 2023: AEMO presented the historical studies Power System Simulation for Engineering (PSS®E) results to all NSPs for their feedback.
- March 2023: AEMO presented the future studies results to all NSPs for their feedback.
- April 2023: AEMO presented the historical studies Power System Computer Aided Design (PSCAD™) results to NSPs for their feedback.
- April 2023: AEMO consulted distribution network service providers (DNSPs) regarding control scheme recommendations which may affect their networks.
- May 2023: AEMO shared a preliminary draft of this report with NSPs and JSSCs for their feedback.
- May/June 2023: AEMO published the draft 2023 GPSRR to allow for stakeholder feedback and submissions[23].
- June 2023: AEMO held an open invitation 2023 GPSRR industry question-and-answer session.
- July 2023: AEMO published the final 2023 GPSRR report.

1.5 Risk management in the NEM

1.5.1 Power system security

Non-credible contingency events, by definition, are not considered reasonably possible during normal power system operation[24], and AEMO is not required to account for them in its real-time management of the power

[21] At 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.

[22] The 2023 GPSRR approach consultation report at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/general-power-system-risk-review-approach-consultation/2023-gpsrr-approach-consultation-report.pdf?la=en sets out AEMO's conclusions in response to submissions received on the approach paper and reasons for updating the approach after considering those submissions.

[23] Note there no NER requirement for AEMO to consult on the GPSRR (having consulted on, and considered submissions in relation to, the approach paper).

[24] A non-credible contingency can also occur when a credible event causes or leads to a further unexpected event, which by definition is then considered non-credible.

system. Various safeguards exist to respond to non-credible contingency events should they occur and reduce their impact on the power system. Key safeguards are:

- EFCSs:
  - UFLS schemes – trip blocks of load to restore the supply demand balance.
  - Over frequency generation shedding (OFGS) schemes – trip blocks of generation to restore the supply demand balance.
- Special protection schemes (SPSs) for particular contingency events – can trip or runback generation, trip load or transmission equipment or initiate other actions to mitigate the impact of power system events.
- Generating system performance capabilities, such as fault ride-through capabilities and frequency controls.
- Other protection systems.

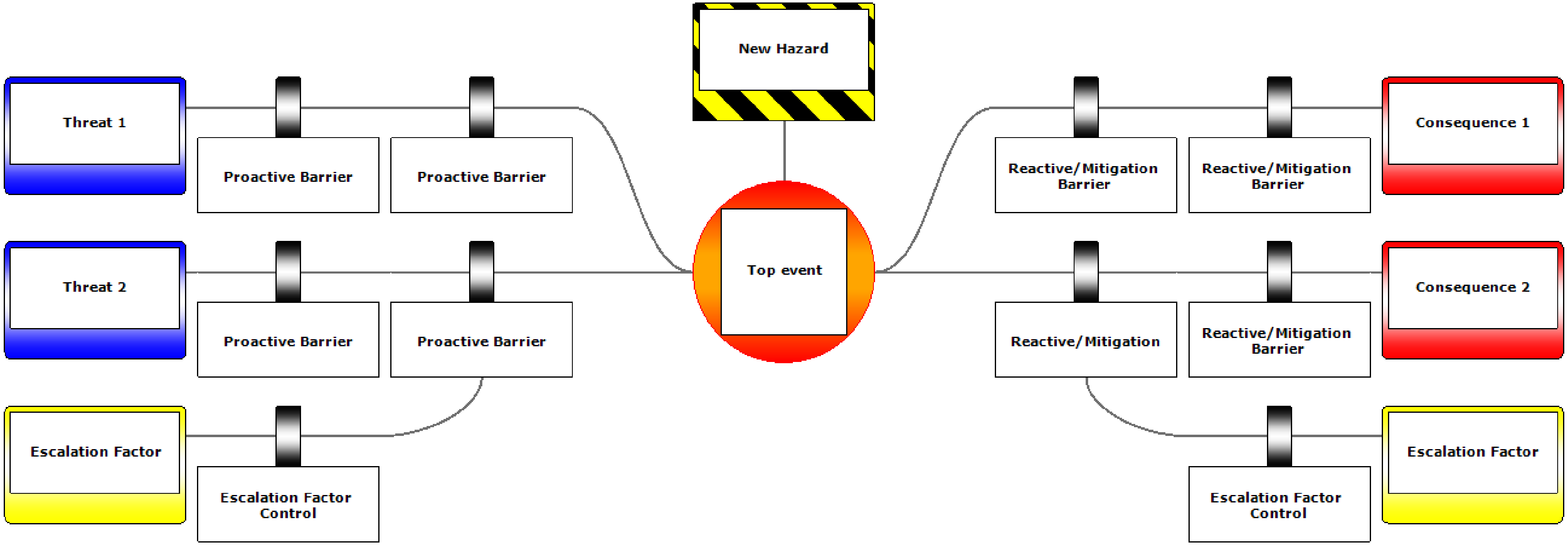
1.5.2 AEMO's risk management methodology

To effectively identify and manage risks associated with operating the power system, AEMO applies the principles of the AS/ISO 31000 risk management framework, undertakes root-cause analysis for major power system events, and has adopted the BowTie methodology, which has the following benefits:

- Provides a graphical representation of all aspects of risk.
- Is simple to understand and effective.
- Gives a logical, structured approach to risk management.
- Is increasingly seen as best practice, especially in high-risk industries.
- Allows interdependencies to be recognised and assessed (vertically and horizontally).

Figure 1 presents a diagram of the BowTie risk assessment method. In the centre of the BowTie is the hazard – hazards can be operations, activities or situations. A hazard has the potential to cause harm, but cannot do so as long as adequate controls are in place. When control of a hazard is lost, a normal situation changes to an abnormal situation. In the BowTie, this event/change is called the top event and appears in the centre of the diagram. For example, a top event could be a frequency excursion on the power system. To the far left of the top event are the threats, the things that could cause a top event to occur.

Figure 1 BowTie risk evaluation diagram



1.5.3 Evolution of the risk review

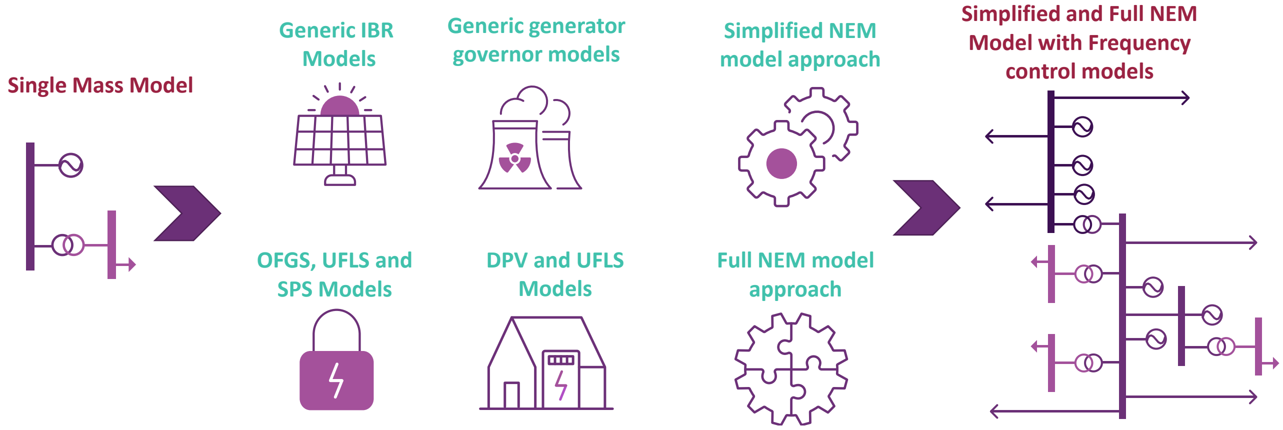
From 2023, the GPSRR replaces and expands on the scope of the previous biennial PSFRR. The risks that can be assessed in the GPSRR are no longer limited to non-credible contingency events and can involve cascading outages from causes other than uncontrolled changes in frequency. However, as the GPSRR is a more frequent review, the number of risks studied in depth for each review is limited. The risks studied for the GPSRR are identified through a prioritisation process in consultation with NSPs and other interested stakeholders, as well as by considering recent operational experience and power system incidents.

AEMO has made key improvements to the modelling of power system risks since the initial PSFRR in 2017, including:

- Adopting generic governor models with primary frequency response (PFR) settings where existing governor models do not exist.
- Inclusion of generic inverter-based resources (IBR) models for legacy IBR plants that do not have models.
- Inclusion of OFGS and UFLS models.
- Inclusion of distributed energy resources (DER) models.
- Addition of models representing key SPSs, particularly those associated with major NEM interconnectors.
- Use of the AEMO composite load model (CMLD) in all GPSRR historical studies.
- Adopting Operations and Planning Data Management System (OPDMS) full NEM network models for historical study cases.
- Lumping of distributed photovoltaic (DPV) generation to bus locations in the OPDMS full NEM model based on AEMO DPV mapping data.
- Use of benchmarked future simplified NEM network model with Project EnergyConnect (PEC) Stage 2 included.

The modelling improvements are figuratively represented in Figure 2.

Figure 2 PSFRR/GPSRR study model improvements in full OPDMS and in NEM simplified models since 2017



To validate the accuracy of the models used for the 2023 GPSRR studies, the model responses were benchmarked against several real power system event measurements (see 2022 and 2020 PSFRR for benchmarking results[25]).

1.6 Key updates since the 2022 PSFRR

Since the 2022 PSFRR, a number of key reforms and publications have been progressed or completed. Below is a summary of these work fronts which influence the scope, considerations and assumptions for the GPSRR.

Primary Frequency Response (PFR) incentive arrangements

On 8 September 2022, the Australian Energy Market Commission (AEMC) made the National Electricity Amendment (Primary frequency response incentive arrangements) Rule 2022 (PFR incentives rule).

The PFR incentives rule provides enduring arrangements to support the control of power system frequency through mandatory PFR and incentives for plant behaviour that reduces the overall cost of frequency regulation during normal operation. Consultation has recently closed on the final PFR requirements to replace the interim requirements by 8 May 2023[26], while the incentives framework is scheduled to come into effect in June 2025[27].

Refer to Appendix A3 for further details on PFR modelling in the 2023 GPSRR.

Engineering Roadmap to 100% Renewables

AEMO published its *Engineering Roadmap to 100% Renewables* report in December 2022[28], building on the Engineering Framework[29]. The report aims to provide a technical base to inform industry prioritisation of steps necessary to securely, reliably and affordably transition. It sets out AEMO's view of the technical, engineering, and operational actions required to prepare the NEM to operate at 100% instantaneous renewable penetration for the first time by identifying the preconditions that need to be satisfied to transition to and operate at 100% renewables. These can be considered 'target end-state objectives' that Roadmap actions are designed to meet.

For each precondition, the Roadmap assesses current and emerging challenges associated with achieving the end state objective. This highlights both 'present forward' issues relevant today and in the near term, and also 'future back' issues anticipated to emerge at very high renewable penetrations.

On this basis, the Roadmap identifies actions necessary to achieve the precondition, starting from today's current state to the end state objective.

The GPSRR links directly to actions identified in the Roadmap report, listed in Table 2, along with the associated preconditions they are contributing to addressing.

[25] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

[26] For information on this consultation, please see https://aemo.com.au/consultations/current-and-closed-consultations/primary-frequency-response-requirements.

[27] For consultation on the incentive (frequency performance payment) project and its implementation, please see https://aemo.com.au/initiatives/major-programs/frequency-performance-payments-project.

[28] At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf.

[29] At https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

Table 2 Relationship between GPSRR and actions identified in the *Roadmap to 100% Renewables* report

Roadmap section	Precondition for first 100% renewable periods	Identified actions
Frequency and inertia	Ability to keep system frequency within defined limits following credible and non-credible events, including rate of change of frequency (RoCoF) containment and effective emergency frequency control arrangements	AEMO and NSPs to assess and maintain adequacy of emergency frequency control schemes and management arrangements.
Transmission	Resilient transmission network design and system performance outcomes	Undertake GPSRR annually to review a prioritised set of risks, events, and conditions that could lead to cascading outages or major supply disruptions. Review the adequacy of current approaches to managing these risks and options for their future management.

System strength framework reform

In October 2021, the AEMC made the National Electricity Amendment (Efficient management of system strength on the power system) Rule 2021[30]. This introduced a revised framework for planning and operating the networks for efficient levels of system strength, requiring an updated System Strength Requirements Methodology (SSRM)[31], and updated System Strength Impact Assessment Guidelines (SSIAG)[32].

AEMO has completed a public consultation[33] to update the SSRM (from 1 December 2022) and SSIAG (from 15 March 2023) to reflect the amending rule, which makes the following key changes:

- A new power system standard for system strength from 1 December 2022:
  - A minimum fault level requirement for power system security in megavolt-amperes (MVA).
  - A requirement for stable voltage waveforms at connection points to host forecast levels of inverter-based resources in megawatts (MW).
- System Strength Service Providers (SSSPs) must plan to meet the "system strength standard specification" (forecast minimum requirements and sufficient system strength for stable voltage waveforms based on forecast levels of IBR), by 2 December 2025.
- Large new and altered inverter-based connections (including large loads and market network service facilities) will be assessed for their "general system strength impact". This includes both their adverse system strength impact and the reduction in available fault level they cause at their connection point.
- A general system strength impact may be self-remediated or, where available, by paying a system strength charge representing a proportionate contribution to the investment required to achieve the system strength standard specification.
- New minimum access standards (NER S5.2.5.15, S5.3.11 and S5.3a.7) requiring relevant plant to remain connected and operate stably at a specified short circuit ratio (SCR) of not more than 3.0 (in addition to compliance with other clauses of NER S5.2.5).

[30] At https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system. At https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[31] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf?la=en.

[32] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/ssrmiag/final-report/system-strength-impact-assessment-guideline_v2.pdf?la=en.

[33] At https://aemo.com.au/consultations/current-and-closed-consultations/ssrmiag.

System strength assumptions applied in the 2023 GPSRR are detailed further in Section 2.1.1 and Section 4.1.4.

Update to guidelines for identifying reviewable operating incidents

On 29 September 2022, the AEMC Reliability Panel published the final report and final revised guidelines for identifying reviewable operating incidents[34]. The updated guidelines improve the overall efficiency of the process by ensuring only incidents with a significant impact on the power system are reviewed and reported on. The updated guidelines:

- Exclude non-credible contingency events where successful auto-reclose occurred and the system remained in a secure operating state.
- Exclude events where a transmission line tripped at one end only or a single circuit breaker tripped and where the system remained in a secure operating state.
- Exclude events where UFLS schemes operated correctly and only tripped contracted load.
- Exclude non-credible contingency or multiple credible contingencies resulting from sudden or unplanned changes in energy flow.

Reviewable operating incidents are discussed further in Section 3.

Indistinct events rule change

On 3 March 2022, the AEMC made the National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule 2022[35]. This rule amended the contingency event reclassification framework to facilitate clear and transparent identification and management of widespread threats to power system security in abnormal conditions. The changes allow AEMO to take action to mitigate any credible threats to the power system, even if the assets at risk cannot be explicitly identified ('indistinct events').

The rule came into effect on 9 March 2023, together with updated reclassification criteria[36], which are published in AEMO's Power System Security Guidelines[37] (SO_OP_3715). The reclassification criteria cover an expanded range of abnormal conditions that could lead to credible indistinct risks, including widespread bushfires, severe wind, geomagnetic disturbances, floods, widespread pollutants and cyberattacks.

AEMO is required to review all reclassification events at six-monthly intervals and assess the effectiveness of the criteria (proposing improvements where necessary).

Management of widespread risks associated with abnormal conditions is discussed further in Section 6.

Frequency Operating Standard review

On 6 April 2023, the AEMC published the Reliability Panel's final determination on the revised Frequency Operating Standard (FOS)[38], to take effect from 9 October 2023. This aligns with the commencement of the new

[34] At https://www.aemc.gov.au/market-reviews-advice/review-guidelines-identifying-reviewable-operating-incidents.

[35] At https://www.aemc.gov.au/rule-changes/enhancing-operational-resilience-relation-indistinct-events.

[36] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-reclassification-events/contingency-event-reclassification-criteria-review-targeted-consultation-update.

[37] 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.

[38] Final determination and revised FOS at https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022.

market ancillary service arrangements for very-fast contingency frequency control ancillary services (FCAS). The revised FOS includes the following key changes:

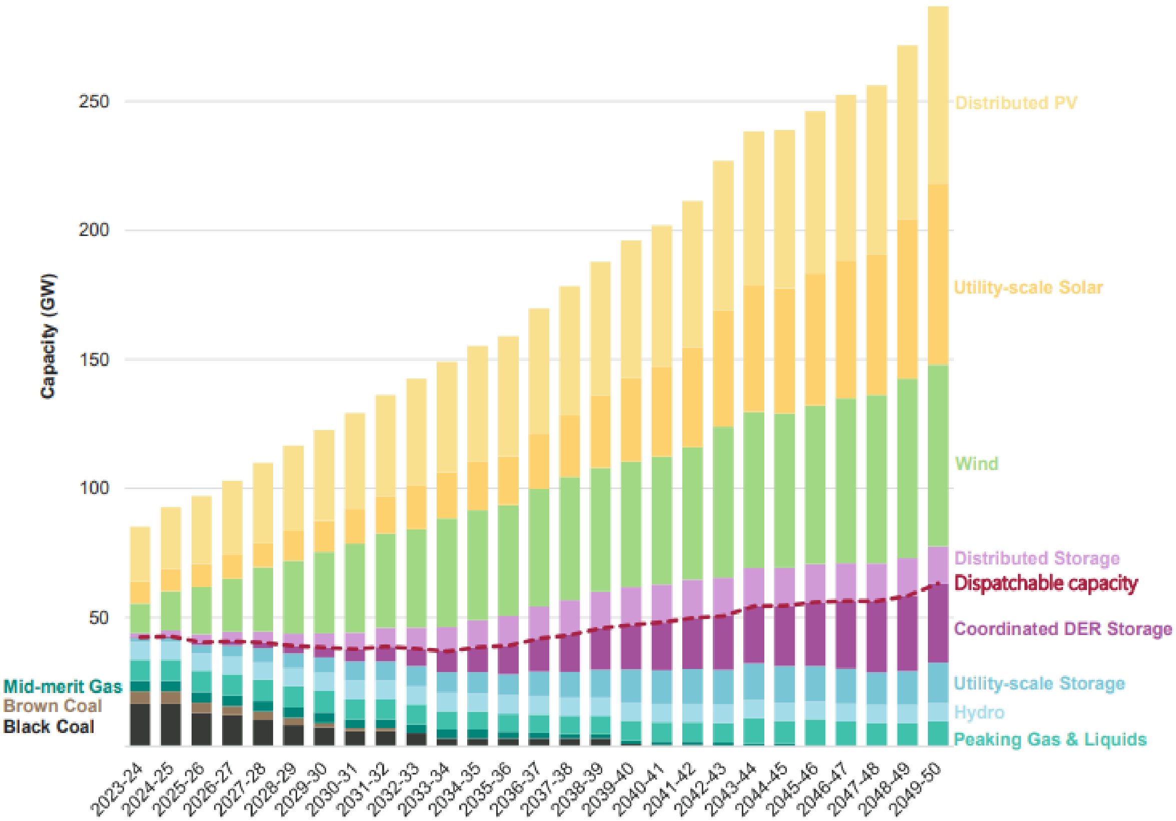
- Narrowing of the operating frequency tolerance band during system restoration from 48-52 hertz (Hz) to 49-51 Hz.
- Removal of the 15-second time accumulation limit for both the mainland and Tasmania, while maintaining AEMO's existing reporting requirements through the weekly and quarterly frequency performance reports.
- Addition of a mainland rate of change of frequency (RoCoF) limit of 1 Hz per second (Hz/s) (measured over any 500 millisecond (ms) period) for credible contingencies.
- Addition of a Tasmanian RoCoF limit of 3 Hz/s (measured over any 250 ms period) for credible contingencies.
- Addition of a reasonable endeavours mainland and Tasmanian RoCoF limit of 3 Hz/s (measured over any 300 ms period) for non-credible contingencies or multiple contingency events.
- Reduction of the minimum threshold for a Tasmanian generation event from 50 MW to 20 MW.

2 Industry in transition

2.1 Generation mix

Historically, Australia's electricity needs were met by generation from synchronous machines using hydro power, coal, or gas as their primary energy sources. Over the last decade, significant installation of inverter-based variable renewable energy (VRE) generation (mainly wind and solar) has occurred in the NEM, and several ageing coal-fired generating plants have been retired and decommissioned. More recently, several large-scale battery energy storage systems (BESS) have been commissioned, and significantly more BESS capacity is planned for connection to the NEM. In addition, there have been unprecedented developments in the connection of small DER, mainly in the form of DPV, along with a small uptake of distributed small battery storage systems. More grid-connected energy storage projects, mainly battery energy storage and pumped hydro energy storage projects, are being planned and proposed. Generation using stored energy is likely to become vital for managing the intermittency of VRE, as the generation mix continues to evolve. Figure 3 shows anticipated changes to generation and load composition as described in AEMO's 2022 ISP *Step Change* scenario[39].

Figure 3 Forecast NEM capacity to 2050, 2022 ISP *Step Change* scenario



From https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

[39] The 2022 ISP *Step Change* forecast data were used to set up future study cases (see Section 4.1.4), therefore 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.

2.1.1 System strength

Table 3 shows the minimum number of synchronous generating units that must be dispatched to maintain power system security at present in normal system conditions, and the minimum number assumed to be required in future for each region as per the 2022 ISP forecasting assumptions[40]. The table details that, by financial year (FY) 2025-26, in most regions there will be periods when no large synchronous generating units need to be online to maintain power system security. It must be emphasised that the technical solutions to allow for this outcome have not yet been determined, but it is a useful planning assumption to allow for the identification of potential technical problems and solutions that could arise as the penetration of instantaneous renewables increases.

Table 3 Forecasting power system constraints – synchronous generating units

Region	Condition	No. large synchronous units always online[A,C]
New South Wales	Now	≥7
	From 2025-26	≥0
Queensland	Now[B]	≥11
	From 2025-26	≥0
	Post second Queensland – New South Wales Interconnector (QNI)	≥0
South Australia	Now (synchronous condensers installed)	≥2[D]
	Post Project EnergyConnect stage 2	≥0
Tasmania	Now	≥3
	Post Marinus Link	≥3
Victoria	Now	≥5
	From 2025-26	≥0

A. Numbers shown are high-level planning assumptions only, not operational advice. Comprehensive studies with detailed models will be required closer to these time periods as the power system evolves. When assessing system strength and inertia shortfalls, the requirement to always keep minimum units online is relaxed in market modelling in order to determine timing and size of potential shortfalls.
B. Additional smaller synchronous units may be required online to deliver the minimum synchronous machine dispatch for Queensland.
C. Future AEMO reports such as the System Strength and Inertia reports may test interim numbers of machines as part of their detailed studies and assessments.
D. AEMO and ElectraNet are presently developing and implementing limits advice, and updating operating procedures to facilitate the secure operation of the South Australian power system with a minimum of one large synchronous generating unit online under some operating conditions, prior to PEC stage 2.

Consistent with other planning studies, the 2023 GPSRR has applied market modelling based on AEMO's *Step Change* scenario from the 2022 ISP to project the operational behaviour of synchronous generation units across the NEM and identify potential stability risks for the future studies and dispatch selection, as detailed in Section 4.1.4.

The assumed reduction in the minimum required number of online synchronous generating units poses both challenges and opportunities for the management of risks in the NEM. Managing power system security within the required operating voltage and frequency bands will be challenging. In addition, the FRT capabilities of IBR under reduced fault level and system strength will be an issue, particularly following non-credible contingencies. The impacts of reduced fault levels on power system security, protection devices and generator FRT needs to be evaluated.

[40] From AEMO, 2021 Inputs and assumptions workbook.xlsx, Power System Constraints sheet, 30 June 2022, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en.

2.2 Network augmentations

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[41]. 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 4[42].

Table 4 Committed, anticipated and actionable major transmission projects to June 2028

Project	ISP deliverable date	Status
VNI Minor	November 2022	Committed
Eyre Peninsula Link	February 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	July 2026[B]	Considered Project
Western Renewables Link	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 Project EnergyConnect 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.

2.3 Distributed energy resources

DER are a significant component of the power system, with DPV now supplying up to 47% of underlying demand in the NEM mainland[43] in some periods during 2022. In South Australia, DPV has already supplied up to 93% of underlying demand in some periods. It is therefore essential that AEMO and NSPs consider DER in all aspects of power system planning, including the assessment of credible and non-credible contingencies and the risks assessed in the GPSRR. AEMO has considered DER as part of the 2023 GPSRR studies (see Appendix A3 for dynamic modelling of DER).

2.3.1 Low DER compliance with technical settings

AS/NZS4777.2:2020 is a mandatory standard for small-scale inverters which incorporates changes aimed at improving disturbance ride-through capabilities to minimise system security risks identified by AEMO[44]. However,

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[41] As per 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.

[42] As per 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.

[43] The NEM mainland refers to the synchronously connected regions of Queensland, New South Wales, Victoria and South Australia.

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

AEMO has identified that compliance with technical settings is poor, with a wide range of data sources consistently indicating that less than half of systems installed are set correctly to the required standard. If compliance remains poor, there will be continuing growth in the amount of DER installed with undesirable disturbance ride-through capabilities, leading to increased contingency sizes in the NEM associated with DPV disconnection.

AEMO has highlighted the scale and urgency of this issue in a report on *Compliance of Distributed Energy Resources with Technical Settings*[45]. The report notes that while the impacts of non-compliance are complex and multifaceted, this issue is already leading to considerable challenges that will continue to worsen until DER compliance is addressed. AEMO notes that some of the DER-related system challenges and impacts are approaching intractability. Poor disturbance ride-through of DER is identified as the most serious and urgent barrier to achieving successful, secure and reliable operation of the NEM and Wholesale Electricity Market (WEM) with high levels of DER.

AEMO's findings highlight the importance and urgency of improving compliance, with a range of industry efforts required to reach a target of at least 90% compliance of new installations with AS/NZS4777.2:2020 by the end of 2023. AEMO also shares insights to inform improvements to the relevant governance frameworks to maintain and further improve that level of compliance. Specific actions that could contribute to achieving this target are proposed in the *Compliance of Distributed Energy Resources with Technical Settings* report, for industry consideration.

Additionally, as part of the active review into consumer energy resources (CER) technical standards, the AEMC has made 12 draft recommendations for immediate action that seek to increase future and existing compliance with CER technical standards[46]. It has also made a draft recommendation that jurisdictions and energy market bodies work together to explore the options and viability of reforming the regulation of current and future CER technical standards from a national perspective.

2.4 Management of frequency

The rapid transformation of the power system creates a range of challenges for managing power system frequency within the ranges specified in the FOS. Management of frequency in different frequency ranges is discussed below:

- Normal operating frequency band (NOFB) – the PFR provided by synchronous generators, IBR and BESS is vital to regulation of power system frequency within the NOFB under normal operating conditions, supported by regulation FCAS. The FCAS currently provided by retiring fossil fuel plants will need to be sourced from new sources such as BESS.
- Operational frequency tolerance band (OFTB) – the regulation of power system frequency within the OFTB is required for credible contingencies, with contingency FCAS markets being the key control mechanism. As more synchronous generation is displaced, meeting the FOS requirements within the containment and stabilisation bands in terms of frequency magnitude and periods will be challenging. The introduction of new very fast FCAS markets from late 2023 is expected to assist in managing power system frequency following

[45] 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.

[46] See https://www.aemc.gov.au/market-reviews-advice/review-consumer-energy-resources-technical-standards.

credible contingencies, allowing for the expected loss of inertial and frequency response support provided by conventional generation resources.

- Extreme frequency excursion tolerance limit (EFETL) – AEMO must use ‘reasonable endeavours’ to limit power system frequency to within the EFETL following non-credible contingencies. EFCSs are a key tool to manage power system frequency within the EFETL. As detailed in Section 6.3, at present, UFLS is in operation in all regions, and OFGS is in operation in Tasmania, South Australia and Western Victoria. In future, there is expected to be a further reduction in synchronous inertia and FCAS availability (due to the displacement of synchronous generation by IBR generation) and UFLS availability (due to increasing underlying DPV in UFLS feeders). Therefore, to manage non-credible contingency frequency excursions, UFLS remediation and OFGS schemes will likely be needed to be further considered.

3 Review of incidents

AEMO reviews power system incidents of significance in accordance with NER 4.8.15, referred to as reviewable operating incidents.

Table 5 summarises the key criteria AEMO uses to identify whether an incident is reviewable, and categories used to determine the reporting approach (preliminary and final report for major incidents, or final report only). Consistent with the Reliability Panel's guidelines for identifying reviewable incidents[47], AEMO may also undertake a review of any other events considered to be of significance.

Table 5 Reviewable incidents criteria

Category	Description	Network	Security	Frequency	Voltage	Loss of load/generation
Not reviewable	Credible event or non-credible event that does not impact critical transmission element	Credible contingency	Not insecure for < 30 mins Not non-satisfactory < 5 mins	Within FOS requirements	Within standards	No load shedding (other than disconnections/load shake-off) No loss of generation due to operation of over frequency protection
Reviewable (Minor)	Noteworthy event requiring AEMO to prepare a report (or AEMO chooses to review an event or systemic issue)	Non-credible contingency or multiple contingency	Insecure > 30 mins	Frequency outside 49-51 Hz (mainland) or 48-52 Hz (Tas)	Minor voltage impacts within standards	No automatic or manually initiated load shedding Loss of generation due to operation of over frequency protection
Reviewable (Major)	Significant event requiring AEMO to prepare a report, impacting stakeholder confidence or adverse media exposure	Non-credible or multiple contingency resulting in separation between regions	Non-satisfactory > 5 mins		Voltage collapse resulting in local/widespread transmission system black	Automatic UFLS action or AEMO directed load shedding (other than as contracted)

[47] At https://www.aemc.gov.au/sites/default/files/2022-09/Final%20guidelines.pdf.

For an incident to be reviewable, it must be a noteworthy or significant event on the power system and generally include an impact to power system security, frequency, voltage or result in load disconnection/loss. Based on its experience reviewing power system incidents, AEMO has observed that unexpected power system responses are often identified during power system events. These often increase an event's overall severity; examples of such unexpected responses are:

- Protection mal-operation.
- Unexpected load disconnection.
- Issues with DPV fault ride-through performance.
- Issues with generator fault ride-through performance.
- Issues with fault ride-through of major loads.

3.1 Summary of reviewable operating incidents in 2022-23

To date in financial year 2022-23, there have been two major and 16 minor reviewable incidents:

- Five incidents were caused by human error.
- Three incidents were caused by equipment failure or protection mal-operation.
- One incident was caused by environmental factors (landslide).
- One incident had an unidentified cause.
- Nine incidents remain under investigation.

Details of these reviewable operating incidents can be found in the published incident reports, which are available on AEMO's website once AEMO's review of each incident is concluded[48].

3.2 Relevant recent incidents

3.2.1 NEM market suspension and operational challenges in June 2022

A confluence of high commodity prices, domestic market price caps, planned and unplanned outages of scheduled generating plant, low output from semi-scheduled generation, and high winter demand conditions led to unprecedented challenges operating the NEM. The incident encompasses a series of events associated with low reserve conditions in the NEM between 10 June 2022 and 24 June 2022, including operation of the Queensland – New South Wales Interconnector (QNI) in excess of secure limits on 13 June 2022, spot market suspension from 15 June 2022 to 24 June 2022, and multiple directions for reliability. AEMO published a reviewable operating incident report on this incident in August 2022[49].

[48] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operatingincident-reports.

[49] For full details of this incident, AEMO's findings and recommendations, see https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf?la=en.

Key updates since August 2022

- AEMO triggered the Gas Supply Guarantee in July 2022 to secure additional gas supplies from Queensland-based gas producers to support gas-powered electricity generation in the NEM[50]. This was lifted on 30 September 2022. The Gas Supply Guarantee guidelines expired on 31 March 2023[51].
- On 12 August 2022, Energy Ministers agreed to take a range of actions to support a more secure, resilient and flexible east coast gas market. These actions sought to address the winter 2023 east coast gas supply adequacy concerns raised by both the Australian Competition and Consumer Commission (ACCC) in its July Gas inquiry interim report[52] and AEMO's Gas Supply and System Adequacy Risks[53]. Following the 12 August decision, Energy Ministers agreed in October 2022 to amendments to the National Gas Law required to give effect to the new framework, and in February 2023 to amendments to the National Gas Regulations and National Gas Rules required to underpin that framework.
  - The East Coast Gas System Guidelines relate to the exercise or performance of AEMO's additional directions and trading functions specified in the Minister-initiated *National Gas (South Australia) (East Coast Gas System) Amendment Bill 2022*[54]. They comprise the following Guidelines, explaining the processes to be undertaken by AEMO in response to an identified risk or threat:
    - Gas Reliability and Supply Adequacy Conference Guidelines.
    - Directions Guidelines.
    - Trading Guidelines.
  - The corresponding amendments to the National Gas Rules were incorporated on 4 May 2023[55].
- The 2023 *Gas Statement of Opportunities* (GSOO) for central and eastern Australia was published by AEMO in March 2023. It underlined that, despite increased production commitments from the gas industry since the 2022 GSOO, gas supply in southern Australia is declining faster than projected demand[56].
  - As identified in previous GSOOs, the 2023 GSOO highlighted continued risks of short-term gas supply shortfalls and long-term gas supply gaps arising from reducing production from southern Australia. In particular, the risk of peak day shortfalls including for gas-powered electricity generation continued to be forecast under very high demand conditions in the southern states from winter 2023.
  - Annual physical gas supply from existing, committed and anticipated production was forecast to be adequate before 2027, noting that investments are needed in the near term to ensure operational solutions from 2027, despite falling gas consumption.
- The 2023 *Victorian Gas Planning Report* (VGPR) was also published by AEMO in March 2023. While the Victorian production outlook had improved since the 2022 VGPR Update, Victorian production continued to

[50] See https://aemo.com.au/newsroom/media-release/aemo-takes-further-steps-to-manage-tight-gas-supplies.

[51] See https://aemo.com.au/en/energy-systems/electricity/emergency-management/gas-supply-guarantee#:~:text=The%20Gas%20Supply%20Guarantee%20mechanism,a%20response%20to%20a%20shortfall.

[52] See https://www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2025/gas-inquiry-july-2022-interim-report.

[53] See https://www.energy.gov.au/sites/default/files/2022-10/Gas%20Supply%20and%20System%20Adequacy%20Risks%202022-2023.pdf.

[54] See https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/priorities/gas/proposed-regulatory-amendments-extend-aemos-functions-and-powers-manage-east-coast-gas-supply-adequacy.

[55] See https://www.aemc.gov.au/regulation/energy-rules/national-gas-rules/current.

[56] See https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2023/2023-gas-statement-of-opportunities.pdf?la=en.

decline, with large forecast reductions in 2024 and 2027[57]. Total available Victorian production was forecast to decline from the 374 petajoules (PJ) produced in 2022 to 315 PJ in 2023 (a 16% reduction) and 190 PJ in 2027 (49% lower than 2022).

- AEMO published a February 2023 *Update to the 2022 Electricity Statement of Opportunities* (ESOO) to reflect significant new relevant information that had become available since the initial publication in August 2022. The ESOO Update identified numerous new developments as well as timing changes to developments underway that have affected the adequacy of supply in some regions[58], and provides an updated outlook of supply adequacy to 2031-32. The 2023 ESOO is set to be published in August 2023.

A summary of the recommendations resulting from the market suspension and the operational challenges in June 2022 and their progress is available in Appendix A1.

3.2.2 Trip of Liapootah – Palmerston 220 kilovolt (kV) lines on 14 October 2022

On 14 October 2022, a landslide impacted the footings of a major double-circuit transmission tower between Palmerston and Waddamana, which connects north and south Tasmania. The following plant tripped:

- Both Liapootah – Waddamana – Palmerston 220 kV lines (No. 1 and No. 2 lines).
- Both of the Waddamana – Lindisfarne No. 1 and No. 2 220 kV Lines (at the Waddamana end only).
- Basslink high voltage direct current (HVDC) interconnector, which was importing 425 MW to Tasmania at the time.
- Musselroe Wind Farm, Lemonthyme Power Station and the disconnection of Cattle Hill Wind Farm at Waddamana substation due to the 220 kV circuit breaker configuration at Waddamana substation and the loss of the 220 kV lines (a total generation loss of 234 MW).
- Approximately 530 MW of electrical load in Tasmania (480 MW of this being industrial load).

As a result of this incident, North and South Tasmania remained connected only via the remaining in-service Waddamana – Palmerston 110 kV line. With the 220 kV lines out of service, any subsequent trip of this 110 kV line would split Tasmania into two separate electrical islands.

To maintain system security with only one 110 kV line connecting North and South Tasmania, AEMO implemented the following operational measures:

1. Active power flow on the Palmerston – Waddamana 110 kV line was constrained below 15 MW in both directions.
2. Constraints were invoked, including an equation that constrained South Tasmania generation to less than (or equal to) South Tasmania demand. This constraint ensured the published pre-dispatch (PD) and short-term (ST) projected assessment of system adequacy (PASA) reserves for Tasmania reflected reserves in North Tasmania where the regional reference node is located.

[57] See https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2023/2023-victorian-gas-planning-report.pdf?la=en.

[58] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/february-2023-update-to-the-2022-esoo.pdf?la=en&hash=1AED91846C35DE3DE0BFC071A2228EAD.

3. Additional reporting tools were developed to assess system reliability for South Tasmania. AEMO closely monitored the power system in South Tasmania during the abnormal network configuration prior to one of the failed 220 kV lines being returned to service.
4. AEMO discussed a planned outage of the Gordon hydro power station (432 MW capacity) with Hydro Tasmania given the network configuration following this event and ongoing risk to system security. The planned outage was subsequently cancelled to maximise available generation and FCAS in South Tasmania.
5. On 19 October 2022, the damaged sections of the 220 kV lines were disconnected allowing the Liapootah – Waddamana line to be returned to service.
6. On 2 December 2022, permanent line repairs were completed and the Liapootah – Palmerston – Waddamana No. 1 and No. 2 220 kV Lines were returned to service.

AEMO's review has concluded that the power system remained secure, and the FOS was met in response to this incident and during the subsequent operation of Tasmania while temporary circuit repairs were ongoing.

AEMO published the final reviewable incident report for this event on 30 June 2023[59].

3.2.3 Trip of South East – Tailem Bend 275 kV lines on 12 November 2022

On 12 November 2022, a double-circuit transmission tower failure 7 kilometres (km) south of Tailem Bend substation resulted in the synchronous separation of South Australia and the rest of the NEM. The following plant tripped:

- Both South East – Tailem Bend 275 kV lines (No. 1 and No. 2 lines).
- The Keith – Tailem Bend 132 kV line tripped at the Tailem Bend end only. This line tripped due to operation of an automated inter-tripping scheme[60].

South Australia was operated as an island until temporary structures were erected, which allowed the South East – Tailem Bend No.1 275 kV circuit to return to service on 19 November 2022, reconnecting South Australia with the rest of the NEM. All requirements necessary to maintain power system security throughout the incident were met. To achieve this, three key challenges had to be managed:

- The size of the maximum credible contingency event had to be maintained within the capability of the available frequency control resources available in the South Australia island.
- Minimum combinations of scheduled units had to remain online within South Australia to provide adequate system strength in the region.
- Sufficient levels of frequency control resources had to be online to meet the FOS for any credible contingency event. Due to the South Australia island condition, AEMO sourced all FCAS from within the South Australia island. As a result of this, South Australia FCAS prices experienced significant volatility, with the administered price cap being reached for some FCAS services within the region.

[59] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-liapootah---palmerston---waddamana-no-1-and-no-2-220-kv-lines.pdf?la=en.

[60] This automated scheme is in place to protect the Keith – Tailem Bend 132 kV line from being thermally overloaded following a contingency on both South East – Tailem Bend 275 kV lines.

To maintain power system security within the South Australia island, AEMO optimised the dispatch of scheduled and semi-scheduled generating units and issued 4.8.9 instructions to ElectraNet to maintain operational demand above specified thresholds. To comply with these 4.8.9 instructions, ElectraNet instructed SA Power Networks to maintain the South Australia operational demand above the necessary threshold each day. SA Power Networks applied a range of mechanisms to curtail DPV on each day from 13-17 November and 19 November 2022, with curtailment lasting between four and nine hours each day and reaching a maximum of approximately 410 MW. This DPV curtailment successfully reduced the largest credible contingency in the South Australia island to a secure operating limit.

AEMO published the final reviewable incident report for this event on 26 May 2023[61].

[61] For the full report, see https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf?la=en.

4 Study methodology

4.1 Study overview

This section describes the assessment approach for historical and future study cases. The 2023 GPSRR review studies were carried out in PSS®E and PSCAD™ and considered historical and future operating scenarios using both full OPDMS and simplified NEM models. Details of network, dynamics, SPS, DPV, UFLS and OFGS models used for the studies are included in Appendix A3. Appendix A3 also covers the methodology used for historic and future studies, modelling assumptions and limitations, as well as details of network augmentations considered in the assessment.

4.1.1 Historical contingencies studied

Table 6 shows the contingencies identified in the 2023 GPSRR approach paper[62] as potential existing system risks. These contingencies were assessed under historical operating conditions.

Table 6 Identified contingencies

Contingency	Contingency description
Risk 1 (Wagga contingency)	Loss of line 62: 330 kV Wagga – Jindera and line 63: 330 kV Wagga – Darlington Point
Risk 2 (Tamworth contingency)	Tamworth double 330 kV bus trip (Sections 1 and 3) due to circuit breaker (CB) failure of bus coupler CB 5102
Risk 3 (Mount Piper contingency)	Non-credible loss of Bayswater – Mount Piper (5A3) and Mount Piper – Wollar (5A5) 500 kV lines

4.1.1.1 Wagga contingency

Table 7 details the contingency risks for the Wagga contingency. Figure 4 shows the geographic location of the Wagga contingency.

Table 7 Historical Wagga contingency

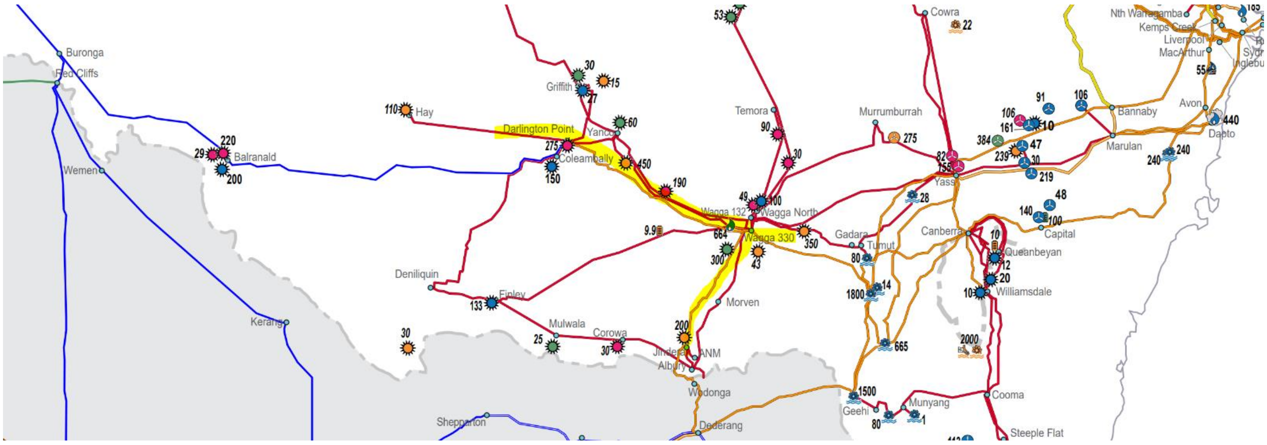
Contingency	NSW: Loss of line 62: 330 kV Wagga – Jindera and line 63: 330 kV Wagga – Darlington Point (see Figure 4)
Likelihood	Unlikely (1% to 10% annual probability)
Impact	Major (loss of supply to a large portion of a state, for any duration) The double-circuit contingency is likely to impact IBR FRT and post event system voltage management. Could cause generation lack of reserve (LOR) conditions.
Risk conditions	• High flows in lines 62, 63, and 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.

[62] 2023 General Power System Risk Review approach paper, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/general-power-system-risk-review-approach-consultation/2023-gpsrr-approach-paper-for-consultation.pdf?la=en.

Contingency	NSW: Loss of line 62: 330 kV Wagga – Jindera and line 63: 330 kV Wagga – Darlington Point (see Figure 4)
	• High QNI QLD export and high Heywood interconnector (HIC) SA export. • High DPV in NSW and VIC regions. • Low UFLS in the NEM regions.
Existing management strategies	UFLS
Potential solutions	Protected event. SPS may not be a practical solution due to PEC commissioning.
Study software	PSS®E and PSCAD[TM][A]
Risk raised by	2022 PSFRR, Transgrid

A. Risk 1 (Wagga contingency) was also studied in PSCAD[TM] to evaluate IBR fault ride-through (FRT) in greater detail.

Figure 4 Geographical location of Wagga contingency



4.1.1.2 Tamworth contingency

Table 8 details the contingency risks for the Tamworth contingency. Figure 5 and Figure 6 show the simplified single line diagram and the geographic location of the Tamworth contingency, respectively.

Table 8 Historical Tamworth contingency

Contingency	NSW/QLD: Tamworth double 330 kV bus fault and CB failure of bus coupler CB 5102, bus section trip (Sections 1 and 3) (see Figure 5 and Figure 6)
Likelihood	Unlikely (1% to 10% annual probability)
Impact	Major (loss of supply to a large portion of a state, for any duration.) Thermal overloads, generation loss, frequency excursions, UFLS operation.
Risk conditions	• 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 Heywood interconnector (HIC) export /import. • High DPV in NSW and VIC regions. • Low UFLS in the NEM regions.
Existing management strategies	UFLS
Potential solutions	Control scheme, UFLS
Study software	PSS®E
Risk raised by	Transgrid

Figure 5 Tamworth contingency simplified single line diagram

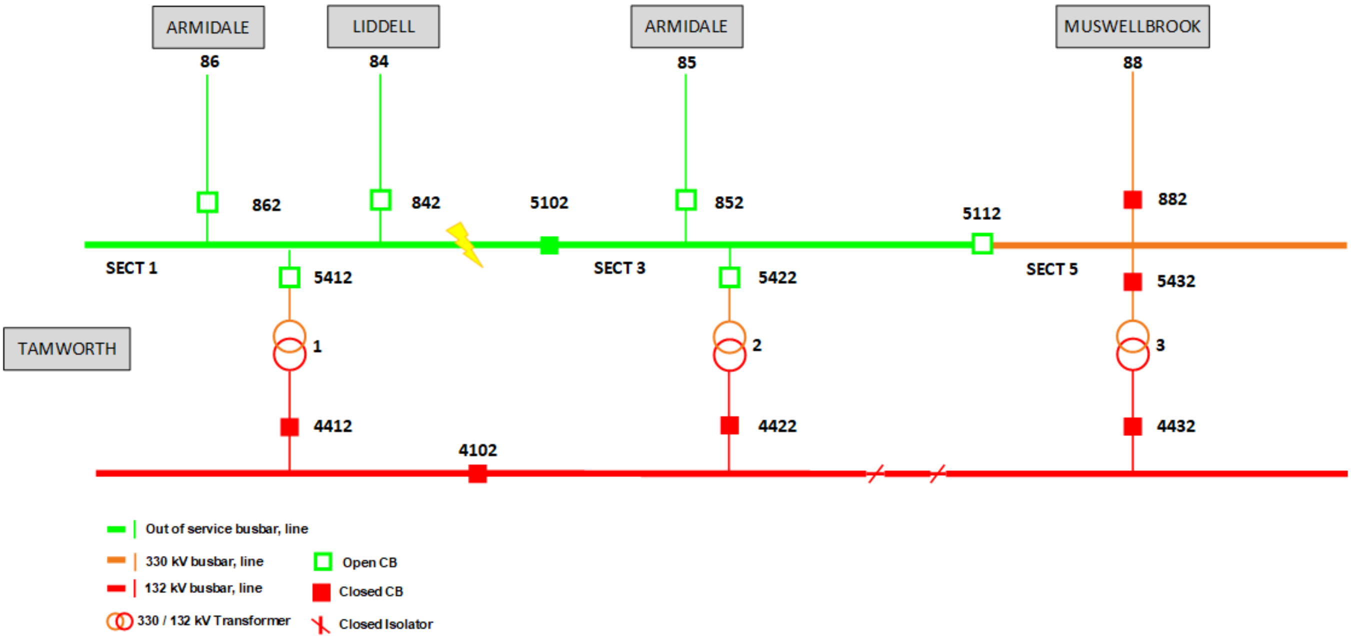
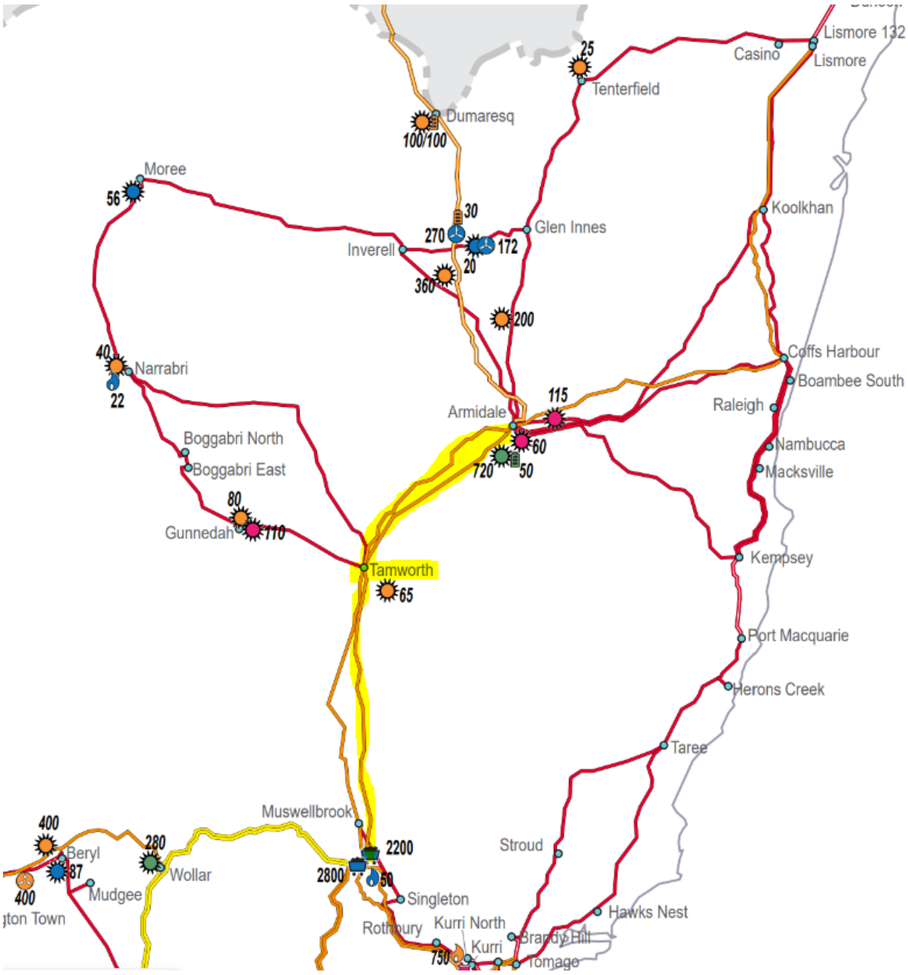


Figure 6 Geographical location of Tamworth contingency



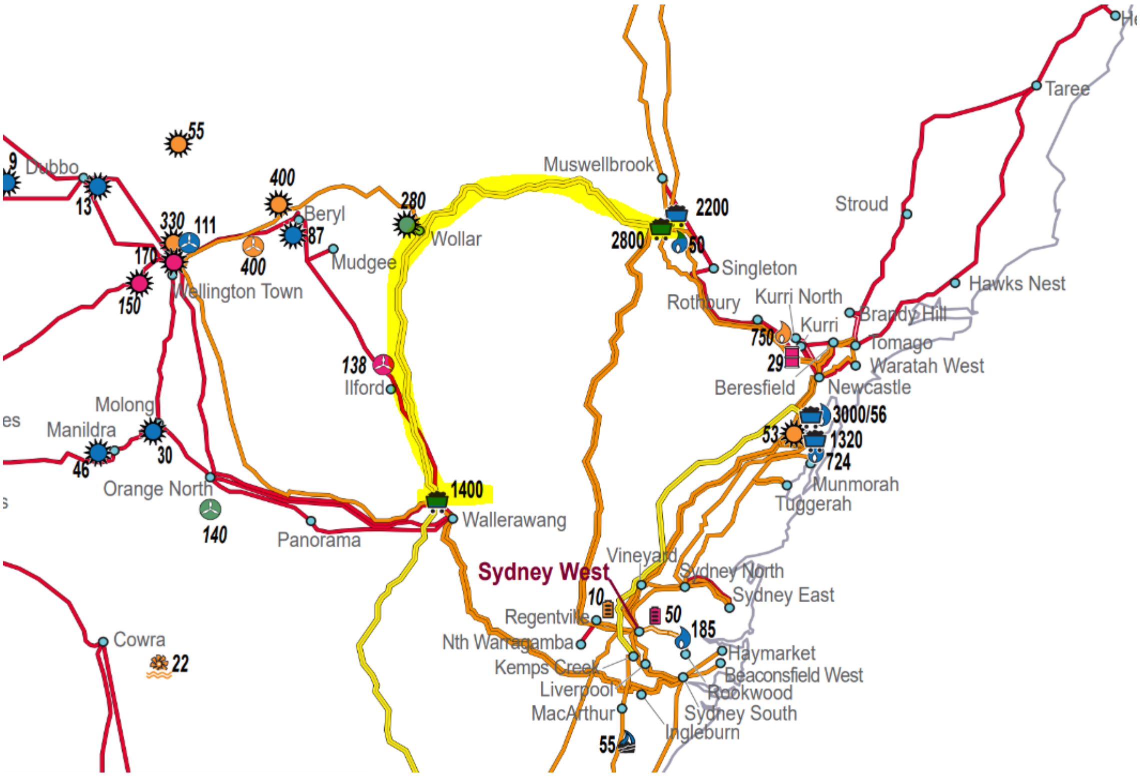
4.1.1.3 Mount Piper contingency

Table 9 details the contingency risks for the Mount Piper contingency. Figure 7 shows the geographic location of the Mount Piper contingency.

Table 9 Historical Mount Piper contingency

Contingency	NSW: Non-credible loss of Bayswater – Mount Piper (5A3) and Mount Piper – Wollar (5A5) 500 kV lines (see Figure 7)
Likelihood	Likely (51% to 90% annual probability) Tripped twice in past three years.
Impact	Major (loss of supply to a large portion of a state, for any duration.) Thermal overloads, generation loss, frequency excursions, UFLS operation.
Risk conditions	• 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 Heywood interconnector (HIC) export /import. • High DPV in NSW and VIC regions. • Low UFLS in the NEM regions.
Existing management strategies	Identified as vulnerable line – contingency is reclassified as credible during a lightning storm if a cloud to ground lightning strike is detected within a specified distance of these lines. End date for proven state is 2027 following a lightning incident in October 2022.
Potential solutions	Reclassification and management via network constraints, UFLS, control scheme
Study software	PSS®E
Risk raised by	AEMO for the 2023 GPSRR

Figure 7 Geographical location of Mount Piper contingency



4.1.2 Historical snapshot selection

This section of the report presents the approach taken to determine the snapshots for the contingencies to be assessed in 2023 GPSRR under historical operating conditions.

AEMO selected historical snapshots based on network conditions that represent the system operating boundaries for each contingency. These network conditions (see Appendix A3) are grouped according to the contingencies as follows:

- Risk 1 (Wagga contingency).
- Risk 2 (Tamworth contingency).
- Risk 3 (Mount Piper contingency).
- NEM boundary conditions.

Table 10 shows the overview of selected timestamps for each scenario with key network conditions and their levels. Appendix A3 contains the maximum and minimum values that were used to calculate the percentages for each parameter.

Table 10 Summary of historical case dispatches

Case	Timestamp	Key system condition	NEM demand (MW)	NSW net UFLS (MW)	QLD net UFLS (MW)	SA net UFLS (MW)	VIC net UFLS (MW)	Synch generation (MW)	IBR generation (MW)	DPV generation (MW)	NEM inertia (MWs)	QNI power flow (QLD export +ve) (MW)	HIC power flow (SA export +ve) (MW)
1	31/01/2022 17:31	Maximum NEM demand	30,128 (100%)	7,620	4,221	1,790	4,713	28,581 (93%)	3,555 (41%)	2,233 (21%)	116,800	-152 (21%)	-21 (3%)
2	17/10/2021 13:01	Minimum NEM demand	11,893 (0%)	3,729	2,743	40	1,407	9,402 (31%)	3,545 (41%)	8,973 (85%)	81,800	474 (37%)	412 (61%)
3	6/07/2021 18:00	Maximum Synchronous Generation	28,739 (92%)	5,686	3,495	1,509	4,125	30,680 (100%)	482 (6%)	0 (0%)	145,500	772 (60%)	358 (53%)
4	17/04/2022 12:01	Minimum Synchronous Generation	13,104 (7%)	3,866	2,426	635	1,102	8,491 (28%)	5,710 (66%)	7,295 (69%)	79,300	62 (5%)	237 (35%)
5	6/06/2022 12:31	Maximum IBR Generation	20,103 (45%)	3,861	2,526	1,079	2,778	13,085 (43%)	8,664 (100%)	5,659 (53%)	92,600	205 (16%)	208 (31%)
6	17/06/2022 17:31	Minimum IBR Generation	26,281 (79%)	6,314	3,518	1,385	3,806	27,905 (91%)	415 (5%)	3 (0%)	133,600	1,238 (97%)	187 (28%)
7	14/12/2021 12:31	Maximum DPV Generation	15,799 (21%)	3,273	2,604	226	1,769	13,119 (43%)	4,059 (47%)	10,604 (100%)	85,100	125 (10%)	143 (21%)
8	19/01/2022 20:31	Minimum DPV Generation	22,616 (59%)	4,812	4,039	1,274	2,544	19,059 (62%)	5,618 (65%)	0 (0%)	105,900	-561 (76%)	-235 (34%)
9	2/04/2022 10:31	Minimum number of Synchronous units online	16,511 (25%)	4,118	2,695	416	2,170	12,204 (40%)	5,713 (66%)	6,028 (57%)	74,000	59 (5%)	325 (48%)
10	12/02/2022 14:01	Maximum IBR generation near Wagga and Darlington Point regions[A]	15,829 (22%)	4,996	3,550	121	1,589	12,150 (40%)	5,025 (58%)	7,582 (72%)	82,000	288 (22%)	237 (35%)

Case	Timestamp	Key system condition	NEM demand (MW)	NSW net UFLS (MW)	QLD net UFLS (MW)	SA net UFLS (MW)	VIC net UFLS (MW)	Synch generation (MW)	IBR generation (MW)	DPV generation (MW)	NEM inertia (MWs)	QNI power flow (QLD export +ve) (MW)	HIC power flow (SA export +ve) (MW)
11	20/01/2022 10:31	Maximum IBR generation in NSW[B]	18,572 (37%)	4,337	3,518	717	1,556	13,260 (43%)	6,711 (77%)	7,210 (68%)	90,900	-267 (36%)	389 (57%)
12	31/12/2021 11:01	High net DPV generation in NSW and VIC[C]	17,246 (29%)	4,852	2,670	915	2,238	11,516 (38%)	7,174 (83%)	8,898 (84%)	83,900	191 (15%)	1 (0%)
13	1/06/2022 13:01	Maximum generation near Tamworth[D]	20,162 (45%)	3,488	2,338	943	3,356	14,678 (48%)	7,378 (85%)	6,197 (58%)	95,000	809 (63%)	-77 (11%)
14	29/08/2021 10:31	Maximum net southernly flow in 5A3 and 5A5 500 kV lines[E]	17,671 (32%)	4,804	2,986	608	2,174	15,471 (50%)	3,911 (45%)	5,028 (47%)	82,600	1,146 (89%)	281 (42%)
15	30/07/2021 9:01	High generation near Bayswater and Liddell[F]	23,494 (64%)	5,381	2,748	1,290	3,243	18,888 (62%)	6,375 (74%)	3,348 (32%)	92,700	996 (78%)	-381 (55%)

A. IBR generation near Wagga and Darlington Point regions = 1,517 (99%).

B. IBR generation in New South Wales = 3383 (100%)

C. Net DPV generation in New South Wales and Victoria = 5725 (95%)

D. Maximum generation near Tamworth = 531 (94%)

E. Maximum net southernly flow in 5A3 and 5A5 = 1457 (100%)

F. Generation near Bayswater and Liddell = 5093 (93%)

4.1.3 Future contingencies studied

As part of the 2023 GPSRR, non-credible events that could lead to QNI instability were assessed against future operating conditions. This follows a recommendation from the 2022 PSFRR based on observations that QNI could lose stability following different non-credible contingency events under both historical and future operating conditions. In particular, studies showed that QNI could lose stability following the loss of the Heywood Interconnector (HIC), causing synchronous separation of both South Australia and Queensland, with potential for further cascading outages[63].

To augment the 2022 PSFRR studies, the 2023 GPSRR future studies assessed other non-credible contingencies across the mainland NEM that could cause QNI instability. These studies aim to support the industry's understanding of the risks of QNI instability and clarify the need for mitigation measures to manage this risk.

South Australia separation at Moorabool Terminal Station (MLTS)

The separation of South Australia at the Moorabool Terminal Station (MLTS) involves the loss of the Moorabool – Mortlake Power Station (MOPS) and MLTS – Haunted Gully Terminal Station (HGTS) 500 kV lines.

This non-credible contingency was studied in detail with historical operating conditions as part of the 2022 PSFRR and the South Australia separation protected event analysis. It was observed that when there is an export into Victoria at MLTS and Queensland is exporting to New South Wales, following South Australia separation at MLTS, there is a possibility that QNI can become unstable, and this leads to the NEM splitting into three islands.

For the 2022 PSFRR, this non-credible contingency was also studied with future operating conditions with PEC Stage 2 integrated using the OPDMS full NEM model. However, due to the complexity of this model, only one import dispatch and one export dispatch was studied. Therefore, for the 2023 GPSRR, this contingency was studied for a wider range of future dispatches using the simplified NEM model to further validate the findings from the 2022 PSFRR.

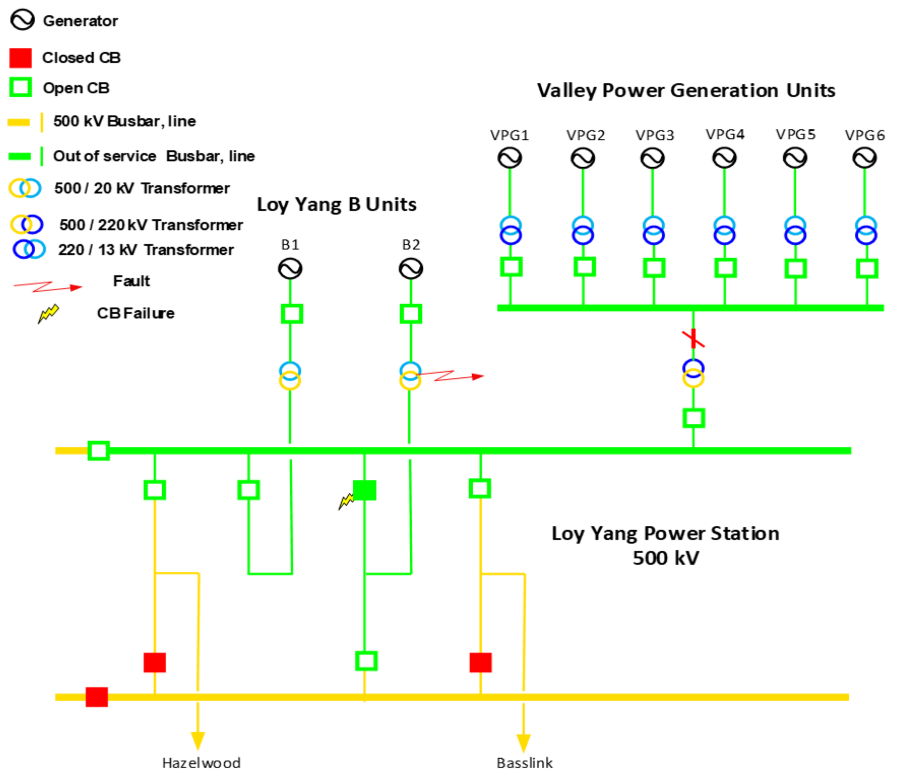
Fault on Loy Yang B unit 2 transformer with Loy Yang No. 3 500 kV bus circuit breaker failure

A fault on the Loy Yang B unit 2 transformer followed by the failure of the single bus coupler circuit breaker that connects the 500 kV No. 3 bus and Loy Yang B unit 2 would result in the circuit breaker fail protection clearing the No. 3 bus, disconnecting both Loy Yang B units as well as Valley Power Station. This could result in the loss of up to approximately 1,300 MW of generation in Victoria. A simplified single-line diagram of the Loy Yang power station and the relevant circuit breakers is shown in Figure 8 below.

This non-credible contingency was studied as an example of a large generation trip scenario in the mainland NEM south of Queensland that has the potential to cause QNI instability and Queensland separation. Hence, the study results are likely representative of the consequences of other generation events that could occur in the mainland NEM.

[63] By inference, as observed during actual power system events.

Figure 8 Simplified single line diagram of Loy Yang power station – CB statuses post fault clearance



Large amount of generation and DPV loss in Southern Queensland

As part of the 2023 GPSRR future studies, the potential for QNI to become unstable during periods of high Queensland import following the loss of generation in Queensland was also assessed. A non-credible bus fault resulting in loss of 1-2 Millmerran units was studied, as previous internal analysis by AEMO indicated that this contingency, when DPV shake-off is accounted for, results in the largest loss of generation in Queensland. As detailed in Appendix A3 and Appendix A4, the simplified NEM model cannot accurately capture network voltages and therefore DPV shake-off following large voltage disturbances. To address this, a fixed 9% of regional Queensland DPV, which aligns well with findings from AEMO's previous studies, was tripped as part of this contingency. This can result in a total generation contingency comprising:

- Millmerran 1 up to 382 MW.
- Millmerran 2 up to 426 MW.
- DPV generation of up to 436 MW.

4.1.4 Future dispatch selection

Forecasting assumption

The 2022 ISP forecasting methodology, set out in the 2021 ISP Methodology[64], was applied to forecast future network dispatch conditions. The following parameters were applied to the 2023 GPSRR future projections:

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

- Short-term schedule half hourly dispatches.
- FY 2027-28.
- High and low demand traces (90% probability of exceedance (POE) and 10% POE).
- Five reference years[65].
- Three solution iterations, to capture different model probabilistic outcomes, such as generation outages.
- The generation build and retirements in the 2022 ISP *Step Change* scenario (see Section 2.1).
- Full network constraints representing the network augmentations assumed in the 2022 ISP *Step Change* scenario (see Section 2.2).
- No units are constrained on for system strength (see Section 2.1.1).

UFLS forecast

ULFS load availability was estimated using the methodology applied for UFLS review studies and was based on the forecast regional load and DPV dispatches.

Dispatch selection

The key system forecast parameters relevant to each contingency that were considered in setting up the study cases are listed below:

- Total NEM inertia (all contingencies).
- Total NEM operational demand (all contingencies).
- DER generation (all contingencies).
- QNI flow (all contingencies).
- UFLS load availability in Queensland (all contingencies).
- South Australia import/export level (MLTS separation).
- Generation between Heywood Terminal Station (HYTS) and MLTS (MLTS separation)[66].
- Total generation of Loy Yang B units and Valley Power units (Loy Yang contingency).
- Millmerran generation (Millmerran contingency).
- Basslink flow (influences the response of the Basslink frequency controller, particularly for the Loy Yang contingency).

A standard set of 12 future dispatches was studied for each contingency. Table 11 shows the overview of selected timestamps for future dispatch with key network conditions and their levels.

[65] AEMO optimises expansion decisions across multiple historical weather years known as “reference years” to account for short- and medium-term weather diversity.

[66] Generation between HYTS and MLTS includes anticipated future generation, but dispatch will be limited by existing constraints in Appendix A3.2.

Table 11 Key NEM parameter values of selected future dispatches

Case	Timestamp	Total regional inertia (MWs)	Total mainland NEM demand (MW)	Total mainland NEM DPV generation (MW)	Total mainland NEM IBR generation (MW)	QNI power flow (QLD export +ve) (MW)	Heywood + PEC flow (SA export +ve) (MW)	Generation between HYTS and MLTS (MW)	Total generation of Loy Yang B and Valley Power units (MW)	Millmerran generation (MW)	Basslink flow (TAS export +ve) (MW)
1	19/03/2028 12:00	SA:4,466 (0 units) QLD: 26,657 (18 units) VIC: 10,598 (5 units) NSW: 21,537 (11 units)	13,550	SA: 164 QLD: 2,032 VIC: 5,111 NSW: 2,894	11,316	-940	-1,300	502	320	671	478
2	2/03/2028 17:30	SA: 5,366 (1 unit) QLD: 45,791 (33 units) VIC: 13,712 (6 units) NSW: 32,399 (16 units)	16,032	SA: 764 QLD: 161 VIC: 918 NSW: 577	6,701	-940	-123	391	1,087	672	478
3	29/02/2028 7:30	SA: 4,466 (0 units) QLD: 20,167 (15 units) VIC: 12,256 (6 units) NSW: 28,352 (15 units)	22,994	SA: 564 QLD: 1,040 VIC: 1,930 NSW: 2,495	18,119	-940	215	861	640	665	-472
4	14/01/2028 11:30	SA: 4,466 (0 units) QLD: 22,330 (16 units) VIC: 12,256 (6 units) NSW: 28,352 (15 units)	6,880	SA: ,2364 QLD: 2,675 VIC: 3,650 NSW: 4,602	9,973	-940	-156	333	640	654	-478
5	21/04/2028 12:30	SA: 4,466 (0 units) QLD: 20,923 (16 units) VIC: 10,288 (5 units) NSW: 16,186 (7 units)	15,160	SA: 1,381 QLD: 2,376 VIC: 4,753 NSW: 5,312	9,313	-940	-184	3	1,119	765	377
6	1/05/2028 11:00	SA: 4,466 (0 units) QLD: 19,788 (14 units) VIC: 10,003 (5 units)	11,778	SA: 2,173 QLD: 4,738 VIC: 4,651	9,244	1,366	625	2	640	674	478

Case	Timestamp	Total regional inertia (MWs)	Total mainland NEM demand (MW)	Total mainland NEM DPV generation (MW)	Total mainland NEM IBR generation (MW)	QNI power flow (QLD export +ve) (MW)	Heywood + PEC flow (SA export +ve) (MW)	Generation between HYTS and MLTS (MW)	Total generation of Loy Yang B and Valley Power units (MW)	Millmerran generation (MW)	Basslink flow (TAS export +ve) (MW)
		NSW: 22,880 (12 units)		NSW: 5,010							
7	21/07/2027 8:30	SA: 4,466 (0 units) QLD: 19,796 (14 units) VIC: 10,598 (5 units) NSW: 23,672 (12 units)	26,658	SA: 409 QLD: 3,136 VIC: 553 NSW: 2,300	18,378	1,354	75	1,174	580	612	478
8	2/02/2028 20:00	SA: 20,717 (12 units) QLD: 33,004 (24 units) VIC: 30,156 (8 units) NSW:42,380 (24 units)	26,653	0	9,328	1,303	900	635	1,390	672	478
9	1/02/2028 19:30	SA: 13,280 (7 units) QLD: 36,846 (27 units) VIC: 31,425 (8 units) NSW: 41,860 (21 units)	30,378	34	8,944	1,412	626	883	1,027	672	478
10	27/07/2027 7:30	SA: 4,466 (0 units) QLD: 27,309 (19 units) VIC: 12,256 (6 units) NSW: 28,346 (13 units)	23,585	SA: 10 QLD: 1,885 VIC: 166 NSW: 1,252	15,535	1,392	499	1,355	640	689	478
11	1/07/2027 18:00	SA: 13,308 (10 units) QLD: 39,768 (28 units) VIC: 29,489 (8 units) NSW: 46,085 (25 units)	20,036	2	2,715	1,401	-200	297	1,154	757	478
12	24/07/2027 11:30	SA: 4,466 (0 units) QLD: 19,450 (14 units) VIC: 12,256 (6 units) NSW: 25,872 (14 units)	15,834	SA: 1,869 QLD: 4,839 VIC: 2,115 NSW: 5,891	12,631	1,365	1,261	764	640	670	478

4.2 Study acceptance criteria

The following acceptance criteria were used when assessing the results of these studies:

- Pre-disturbance and post-disturbance voltages at key transmission node are within an acceptable range.
- Electromechanical oscillations are adequately damped.
- Post fault voltage oscillations are adequately damped.
- System frequencies are maintained with the applicable extreme frequency excursion tolerance limits as defined in the FOS[67].
- No instability or tripping of IBR is observed due to the contingency.
- The non-credible contingency does not lead to the loss or instability of a system interconnector or a cascading failure.
- The PSS®E or PSCAD™ simulation successfully completes, and no numerical instability is observed.

Table 12 defines the symbols used in the summary of the simulation results detailed in Section 5.

Table 12 Legend for historical results table

Result	Symbol
Pass	☑
Fail	☒

[67] The FOS is available at https://www.aemc.gov.au/sites/default/files/2020-01/Frequency%20operating%20standard%20-%20effective%201%20January%202020%20-%20TYPO%20corrected%2019DEC2019.PDF.

5 Study results and observations

5.1 Historical scenario studies

In this section, the response of the system for the given historical contingencies is assessed. Table 13 shows the assessment of all simulations against the acceptance criteria detailed above.

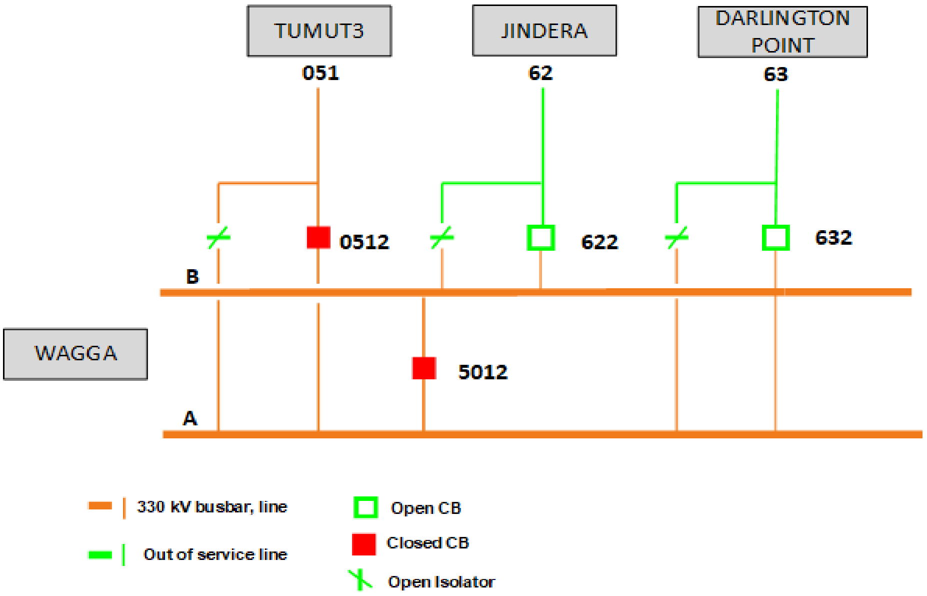
Table 13 Results for historical contingencies

Case	Timestamp	Risk 1 (Wagga contingency)	Risk 2 (Tamworth contingency)	Risk 3 (Mount Piper contingency)
1	31/01/2022 17:31	☑	☒, QNI lost stability, QLD angular separation from NEM	☑
2	17/10/2021 13:01	☑	☒, QNI lost stability, QLD angular separation from NEM	☑
3	6/07/2021 18:00	☑	☑	☑
4	17/04/2022 12:01	☒, EAPT operated to separate SA, SA freq peak = 51.01 Hz and SA OFGS tripped = 28.4 MW	☑	☑
5	6/06/2022 12:31	☑	☑	☑
6	17/06/2022 17:31	☑	☒, QNI lost stability, QLD angular separation from NEM	☑
7	14/12/2021 12:31	☑	☑	☑
8	19/01/2022 20:31	☑	☒, QNI lost stability, QLD angular separation from NEM	☑
9	2/04/2022 10:31	☑	☑	☑
10	12/02/2022 14:01	☑	☑	☑
11	20/01/2022 10:31	☒, EAPT operated to separate SA, SA freq peak = 51.01 Hz and SA OFGS tripped = 10.8 MW	☒, QNI lost stability, QLD angular separation from NEM	☑
12	31/12/2021 11:01	☑	☑	☑
13	1/06/2022 13:01	☑	☒, QNI lost stability, QLD angular separation from NEM	☑
14	29/08/2021 10:31	☒, QNI lost stability, QLD angular separation from NEM	☒, QNI lost stability, QLD angular separation from NEM	☑
15	30/07/2021 9:01	☑	☒, QNI lost stability, QLD angular separation from NEM	☑

5.1.1 Risk 1: Wagga contingency

The non-credible loss Wagga – Jindera (62) and Wagga – Darlington Point (63) 330 kV lines (shown in Figure 9) was assessed assuming the NER primary clearance time of 100 ms[68] and considering the control schemes detailed in Appendix A3. The case results for this contingency are shown in Table 14.

Figure 9 Risk 1 (Wagga contingency) simplified single line diagram



This multiple line loss contingency could impact IBR FRT and post event system voltage management and could cause generation lack of reserve (LOR) conditions. This contingency was studied in PSCAD™ as well as PSS®E due to the possible impact the event could have on system voltages and IBR in the surrounding area – any additional tripping of IBR observed in electromagnetic transient (EMT)/PSCAD™ studies would compound the impact of this contingency.

Table 14 Case results for the Wagga contingency

NSW/NEM frequency nadir/peak (Hz)	NSW + VIC total DPV tripped on DPV inverter settings only (MW)*	Total inter-tripped IBR generation (MW)
49.3 - 50	0 - 221 (0 - 7%)	18 - 865

* Percentage of total online NSW and VIC regional DPV generation tripped on inverter settings.

Key findings

The historical studies of the Wagga contingency identified the following key findings in relation to the acceptance criteria:

- For Case 4 and Case 11, the Emergency Alcoa Portland Tripping (EAPT) scheme (in the performance-based mode[69], mode 3) was found to operate to island South Australia as a result of this contingency. This

[68] See Table S5.1a.2 in NER Chapter 5.

[69] 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.

demonstrates the advantages of changing the EAPT scheme to a topology and performance-based scheme (mode 1), which will prevent unexpected operation due to power swings that may occur following different contingency events. As detailed in Appendix A2, this action has been since been completed consistent with a recommendation in the 2020 PSFRR.

- For Case 14, the Queensland system angle separated from the rest of the NEM, causing numerical instability in the simulation. The sensitivities undertaken for this case indicate that the instability of QNI following this contingency could be prevented by tripping approximately 300 MW of load in New South Wales or constraining the pre-contingent level of inter-tripped generation in New South Wales by a similar amount.
  - However, the integration of PEC into New South Wales will impact the network in New South Wales and could mean the X5 line fast tripping scheme and the associated generation inter-trip schemes are no longer required (the control schemes related to this contingency are detailed in Appendix A3). This would effectively reduce the post-contingent power swing on QNI, thereby reducing the likelihood of Queensland losing synchronism with the rest of the mainland NEM. It is therefore imperative that the relevant NSPs consider the interactions of PEC with existing control schemes when designing the South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS).
- Following the non-credible contingency and the operation of the X5 line tripping scheme, between 18 MW and 865 MW generation was inter-tripped by the relevant control schemes.
  - For this event, apart from generation disconnected due to operation of special protection schemes, additional generation could be constrained following the contingency events in order to resecure the system. There are several constraints that are invoked following the loss of these lines that constrain generation around the Wagga area. Using historical data from FY 2021-22, the total maximum dispatched generation in New South Wales that could be constrained (excluding the inter-tripped generation) is 1,875 MW. The loss of availability of this volume of generation may have an adverse impact on system reserves and result in potential supply disruptions.
- No FRT issues with IBR plants in New South Wales were observed in any of the PSCAD™ cases studied.
- No voltage instability was observed in New South Wales or the rest of the NEM following fault clearance in the PSCAD™ cases studied.
- All other acceptance criteria were met for all the other cases studied.
- Therefore, based on the cases studied, no remedial actions are required to manage the non-credible loss of the 62 and 63 330 kV lines.

Detailed graphs and results for individual cases are included in Appendix A5.

Other observations

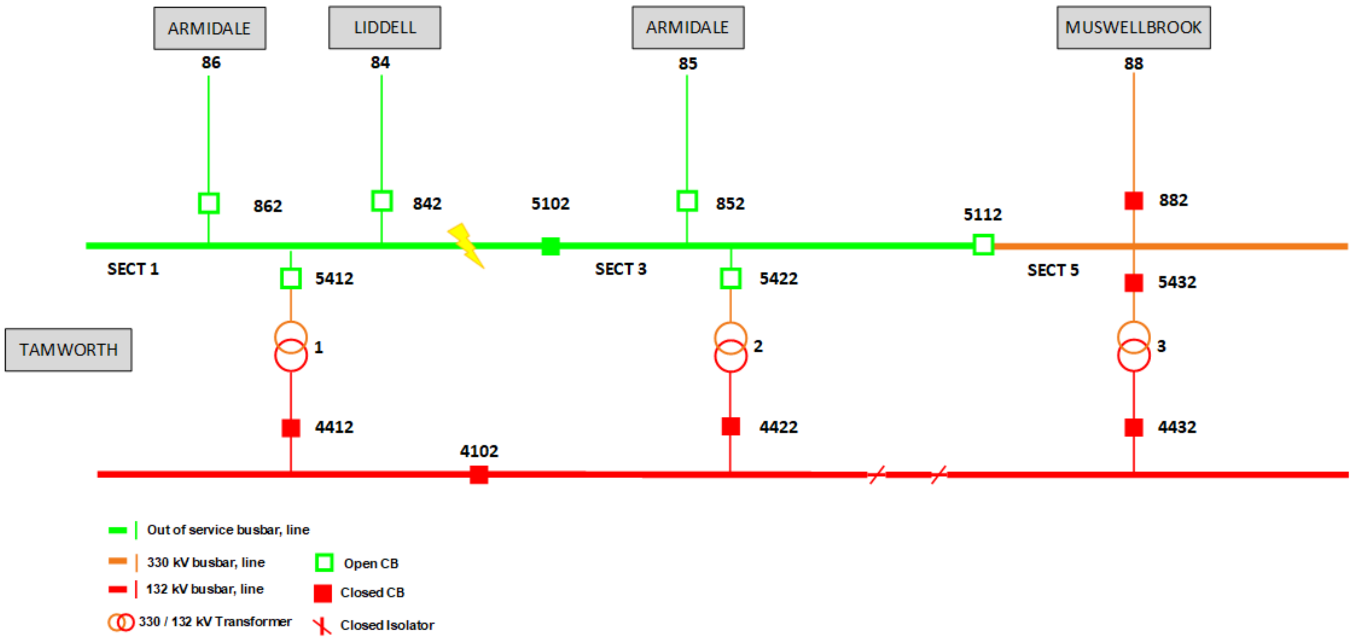
For the two cases for which the EAPT scheme operated (in the performance-based mode, mode 3), following South Australia separation, the frequency in South Australia exceeded 51 Hz and OFGS operated. South Australia OFGS did not operate for any other cases studied.

5.1.2 Risk 2: Tamworth contingency

The non-credible loss of bus sections 1 and 3 due to a fault on the Tamworth 330 kV bus and a circuit breaker (CB) failure of the bus coupler CB 5102 (shown in Figure 10) was assessed assuming the NER S5.1a.8

CB fail fault clearance time of 250 ms, and considering the control schemes detailed in Appendix A3. The case results for this contingency are shown in Table 15.

Figure 10 Risk 2 (Tamworth contingency) simplified single line diagram



This contingency is likely to cause QNI instability as it disconnects the Queensland and New South Wales 330 kV networks at Tamworth. Following fault clearance, Queensland and New South Wales remain connected via the 132 kV network through a single 200 MVA 330/132 kV transformer at Tamworth via Moree and the 132 kV lines through Port Macquarie in New South Wales. The impedance of the connection between Queensland and the rest of the mainland NEM is therefore greatly increased.

Table 15 Case results for the Tamworth contingency

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)*	Number of cases with QNI instability
49.4 – 50.2	49.3 - 50.9	0 - 388 (0-12%)	0 - 116 (0-5%)	8

* Percentage of total online New South Wales and Queensland regional DPV generation tripped on inverter settings

Key findings

Historical studies of the Tamworth contingency identified the following key findings in relation to the acceptance criteria:

- In six of the study cases, QNI lost stability and the Queensland system angle separated from the rest of the NEM following fault clearance, however QNI distance protection did not operate to separate Queensland due to the current remaining below the protection threshold. As the QNI distance protection did not operate, sustained, undamped power swings on QNI were observed.
  - As mentioned above, after this contingency Queensland remains synchronously connected to the rest of the mainland NEM via the remaining 132 kV network in northern New South Wales. The impedance of the connection between Queensland and the rest of the mainland NEM is therefore greatly increased. This

increased impedance was found to lead to instability on QNI and the angular separation of the Queensland region for six of the cases studied

- All other acceptance criteria were met for all the other cases studied.

Detailed graphs and results for individual cases are included in Appendix A5.

Tamworth contingency sensitivities

For cases where QNI lost stability, Transgrid advised that impedance protection on the 132 kV lines connecting Queensland to New South Wales is expected to operate, islanding the Queensland region near Tamworth. AEMO consulted Transgrid to establish sensitivity cases where the Moree – Inverell and Port Macquarie – Taree 132 kV lines are tripped to island Queensland.

In these sensitivity cases, the 132 kV lines were tripped after the angular difference between two connected system buses exceeded 180°, following an additional delay of 6 cycles (120 ms). This represents the action of the impedance protection on the 132 kV lines. For cases where the voltage angle difference along the Moree – Inverell 132 kV corridor did not exceed 180°, sensitivities were completed inter-tripping these lines with the Kempsey – Taree lines following an additional delay of 120 ms. The results of these sensitivities are detailed in Table 16.

Table 16 Sensitivity results for the Tamworth contingency – trip of 132 kV network to island Queensland

132 kV tripping time (s) (Kempsey – Taree 180° exceeded)	NSW/NEM frequency nadir/peak (Hz)	QLD frequency nadir/peak (Hz)	Number of unstable cases (QLD did not island successfully)
5.76 - 9.17	49.4 - 50.2	49.5 - 50.9	1

Sensitivity key findings

- For the majority of the sensitivity studies completed, Queensland successfully formed an island following the trip of both 132 kV corridors. To ensure correct protection operation, AEMO recommends that Transgrid maintain the 132 kV system distance protection and associated equipment with consideration to the criticality and potential impact of its failure.
- AEMO completed additional sensitivities for cases that exhibited QNI instability, tripping load in New South Wales and generation or load in Queensland. These studies indicate that tripping load in New South Wales and generation in Queensland (for Queensland export conditions) and load in Queensland (for Queensland import conditions) can, in some cases, prevent Queensland from losing synchronism with the rest of the mainland NEM.
- In addition, AEMO has identified that, under certain conditions, a CB 5102 failure and subsequent Tamworth busbar trip may not cause Queensland to separate from the NEM. If this sequence of events occurs, AEMO recommends that Transgrid System Operators open the 132 kV interconnections between Queensland and New South Wales manually.
- AEMO notes that the future actionable ISP New England Renewable Energy Zone (REZ) 500 kV network augmentations (with an optimal delivery date of July 2027) could drastically reduce the impact of this contingency, because following fault clearance at Tamworth, Queensland will remain synchronously connected to the NEM via a new double-circuit 500 kV line from the locality of Armidale South to Bayswater via east of

Tamworth[70]. AEMO considers it would be impractical and uneconomic to design and implement an SPS or other controls to specifically mitigate the risks associated with this contingency given the major augmentation planned for 2027.

  – Therefore, AEMO is not recommending an SPS or other risk mitigation to reduce the risk of QNI stability for the Tamworth contingency events at this time.
  – As part of the NSP planning obligations under NER S5.1.8, AEMO recommends that Transgrid confirms network stability will be maintained following the Tamworth contingency post the New England REZ 500 kV network augmentation.

- The CB failure of bus coupler CB 5102 and subsequent trip of the Tamworth 330 kV busbars (Sections 1 and 3) can cause QNI to become unstable. This contingency has the potential to cause sustained power oscillations or the 132 kV network distance protection to operate, leading to separation of the Queensland region from the rest of the NEM. The failure/incorrect operation of CB 5102 is the key event of this incident (with the circuit breaker fail dramatically increasing the impact of this event). Therefore, any action that can be taken to ensure the correct operation of CB 5102 will reduce the likelihood of this incident occurring.
  – Transgrid advised AEMO that CB 5102 was commissioned in 2002 and has a good condition history and that there are no population type issues identified for this asset type. Given CB5102's good condition, AEMO recommends that Transgrid continues to maintain CB 5102 and associated equipment with consideration to the criticality and potential impact of its failure.
- In two cases, the EAPT scheme (in mode 3, the performance-based mode[71]) was found to operate to island South Australia as a result of this contingency and QNI losing stability. This was 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 seconds and the Heywood – South East 275 kV line frequency dropping below 49.7 Hz for more than 100 ms. This demonstrates the advantages of changing the EAPT scheme to a topology and performance-based scheme (mode 1), which is expected to prevent unexpected operation due to power swings that may occur following different contingency events. As detailed in Appendix A2, this action has been since been completed consistent with a recommendation in the 2020 PSFRR.
- For multiple cases, the Tasmania frequency fell below 48.8 Hz following the islanding of Queensland, which resulted in the operation of the Adaptive Under Frequency Load Shedding 2 (AUFLS2)[72] scheme. In a subset of these cases, the Tasmania frequency fell below 48 Hz, triggering additional load shedding through UFLS action.
- No severe thermal overloads of the remaining 132 kV critical lines were observed in any of the cases studied.
- All other acceptance criteria were met for all the other sensitivity cases studied.
- Therefore, based on the cases studied, no remedial actions are recommended to manage the Tamworth contingency, except for the continued maintenance of CB 5102.

[70] See https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en.

[71] 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.

[72] The AUFLS2 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.

Detailed graphs and results for individual cases are included in Appendix A5.

Recommendation 1

Based on findings in relation to busbar faults at Tamworth (Risk 2) AEMO recommends that:

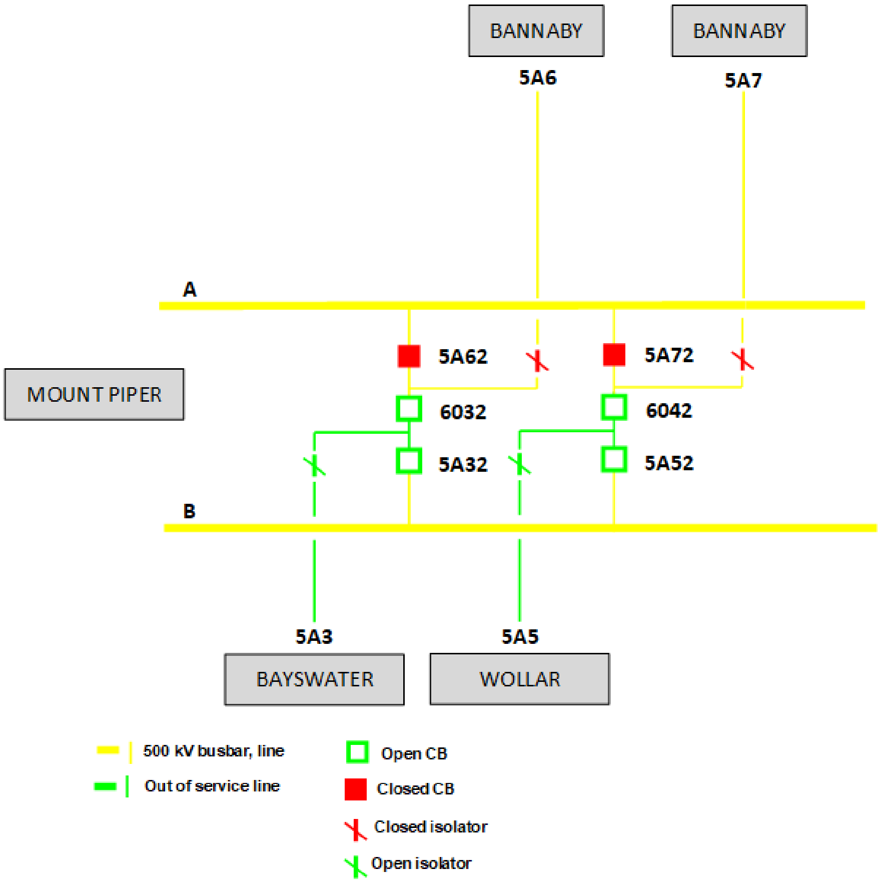
a) Transgrid continues to maintain circuit breaker (CB) 5102 and associated equipment with consideration to the criticality and potential impact of its failure.

b) Transgrid maintains the 132 kV system distance protection systems near Tamworth and associated equipment with consideration to the criticality and potential impact of its failure.

5.1.3 Risk 3: Mount Piper contingency

The non-credible loss of Bayswater – Mount Piper (5A3) and Mount Piper – Wollar (5A5) 500 kV lines (shown in Figure 11) was assessed. Case results are summarised in Table 17. Studies assumed primary fault clearance time of 80 ms consistent with NER S5.1a.8 and considering the control schemes detailed in Appendix A3.

Figure 11 Risk 3 (Mount Piper contingency) simplified single line diagram



As detailed in Section 4.1.1, the 5A3 and 5A5 lines are currently on the vulnerable lines list[73], meaning that they can 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 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 the proven state being extended to 20 October 2027. Currently, no constraint sets are invoked for the reclassification of the non-credible loss of the 5A5 and 5A3 lines.

Table 17 Case results for the Mount Piper contingency

NSW/NEM frequency peak (Hz)	NSW total DPV tripped on DPV inverter settings only (MW)	Number of cases with SPS, EFCS or control scheme operation	Number of unstable cases
50.2	0 - 473 (0-18%*)	0	0

* Percentage of total online NSW regional DPV generation tripped on inverter settings

Key findings

The historical studies of the Mount Piper contingency identified the following key findings in relation to the stated acceptance criteria:

- Flows on the 5A3 and 5A5 500 kV lines varied between 300 MW and 1,457 MW in the historical cases studied, and the net flow in parallel corridors to lines 5A3 and 5A5 varied between 1,286 and 2,663 MW.
- For the daytime cases studied, between 9% and 18% of DPV in New South Wales tripped due to its own inverter settings, and these values are consistent with the DPV voltage tripping observed for contingencies in the same area of the New South Wales system.
- The loss of the 5A3 and 5A5 500 kV lines results in increased flows on the Bayswater – Sydney West, Bayswater – Regentville and Liddell – Tomago 330 kV lines and the Port Macquarie – Taree 132 kV lines.
  - However, no lines exceeded their thermal ratings following the loss of the 5A3 and 5A5 lines for the cases studied.
- All other acceptance criteria were met for all the cases studied.
- The results of the historical studies undertaken indicate that no remedial actions are required to manage the non-credible loss of the 5A5 and 5A3 500 kV lines.
- Given that these lines will remain on the vulnerable line list until 2027 following the recent lightning strike incident, this contingency can be reclassified as credible and managed through network constraints when the risk of lightning is increased in accordance with the Power System Security Guidelines[74].

These key findings are consistent with AEMO's current position that no constraints need to be invoked when this contingency is reclassified as credible due to the 5A3 and 5A5 lines being categorised as vulnerable lines.

Detailed graphs and results for individual cases are included in Appendix A5.

[73] 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.

[74] 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.

5.2 Future scenario studies (Risk 4): Assessment of non-credible events that could lead to QNI instability

In this section, the response of the system for the future contingencies is assessed. Table 18 shows the assessment of all simulations against the acceptance criteria detailed in Section 4.2.

A standard set of 12 future dispatches were studied for each contingency. The key parameters of each of the future dispatch studies are detailed in Table 11 in Section 4.1.4.

Table 18 Future study results

Case	Timestamp	MLTS Contingency	Loy Yang Contingency	Millmerran Contingency
1	19/03/2028 12:00	☒, SA angular separation, QNI tripped to island QLD	☑	☒, QNI tripped to island QLD
2	2/03/2028 17:30	☑	☑	☑
3	29/02/2028 7:30	☑	☑	☒, QNI tripped to island QLD
4	14/01/2028 11:30	☑	☑	☒, QNI tripped to island QLD
5	21/04/2028 12:30	☑	☑	☒, QNI tripped to island QLD
6	1/05/2028 11:00	☑	☒, QNI tripped to island QLD	☑
7	21/07/2027 8:30	☒, QNI tripped to island QLD	☒, QNI tripped to island QLD	☑
8	2/02/2028 20:00	☒, SA angular separation, QNI tripped to island QLD	☒, QNI tripped to island QLD	☑
9	1/02/2028 19:30	☒, SA angular separation, QNI tripped to island QLD	☒, QNI tripped to island QLD	☑
10	27/07/2027 7:30	☒, SA angular separation, QNI tripped to island QLD	☒, QNI tripped to island QLD	☑
11	1/07/2027 18:00	☑	☒, QNI tripped to island QLD	☑
12	24/07/2027 11:30	☒, SA angular separation, QNI tripped to island QLD	☒, QNI tripped to island QLD	☑

5.2.1 Risk 4a: Moorabool contingency

The non-credible separation of South Australia at MLTS was assessed assuming the NER primary protection system clearance time of 80 ms[75]. The results from the studies are shown in Table 19 below.

[75] See Table S5.1a.2 in NER Chapter 5

Table 19 Case results for the Moorabool contingency

Heywood + PEC flow (SA import +ve) (MW)	SA frequency nadir/peak (Hz) A	QLD frequency nadir/peak (Hz)	QLD initial RoCoF (Hz/s)	NSW/VIC frequency nadir/peak (Hz)	SA OFGS generation tripped (MW)	Net UFLS tripped (MW)	DPV tripped on inverter settings only (MW)
-1,261 to 1,300	40 - 53	48.2 - 51.3	0.02 - 1.54	48 - 51	0 - 204	SA: 0 – 1,569 (0 - 99%) QLD: 0 – 1,290 (0 - 59%) VIC: 0 – 2,364 (0 - 69%) NSW: 0 – 1,491 (0 - 48%)	SA: 0 - 132 VIC: 0 - 237 NSW: 0 - 856 QLD: 0 - 232

A. Note that the frequency nadir/peak observed in the studies are more severe due to the angular/synchronous separation of South Australia.

Key findings

The future studies of South Australia separation at MLTS identified the following key findings:

- The QNI distance protection relays operated to trip QNI, resulting in the synchronous separation of Queensland, for six of the cases studied.
  - For five of these cases, QNI was near the maximum export level from Queensland of 1,450 MW. For Case 8 and Case 12, the South Australia export level was high enough to trigger SAIT RAS generator tripping action. For both of these cases, South Australia lost synchronism with the rest of the NEM following separation at Moorabool, followed by QNI being tripped by distance protection.
  - For Case 1, for which QNI was at the maximum import of 950 MW 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. The EAPT scheme operated at 5.3 seconds 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 to trip 560 MW of load in South Australia.
- Based on assumed action of SAIT RAS, the results for Case 1, Case 8 and Case 12 show that Moorabool separation has the potential to cause loss of stability on QNI, which could be exacerbated by the existing SPSs within Victoria and the SAIT RAS due to the effective loss of generation.
- Frequencies in the NEM were maintained within 48 and 52 Hz for all cases, aside from Case 1 where South Australia frequency fell below 47 Hz and cases 10 and 12 where South Australia frequency exceeded 52 Hz, following fault clearance.
- All other acceptance criteria were met for all the other cases studied.

Detailed graphs and results for individual cases are included in Appendix A6.

Other observations

Additional observations that do not impact the acceptance criteria are outlined below:

- The EAPT scheme operated for several cases, including cases where South Australia was exporting due to the transient reduction in South Australia frequency below 49.7 Hz with the mainland NEM frequency. The EAPT performance criteria delay time is currently set at 170 ms – consistent with Recommendation 3 detailed in Section 5.2.5, it is imperative that AEMO, AEMO Victorian Planning (AVP), ElectraNet and Transgrid continue collaborating as part of the PEC System Integration Steering Committee (SISC) to ensure that the SAIT RAS operates effectively in conjunction with existing NEM system protection schemes, such as EAPT.

- As detailed in Appendix A3, the increase in South Australia OFGS capacity already recommended by AEMO will likely assist with arresting over frequencies in the region.
- NEM UFLS and South Australia OFGS operated for multiple cases – refer to results in Table 19.
  - A large amount of mainland UFLS tripped for many of the cases studied – up to a total of more than 4,000 MW. Comparatively, the trip of multiple generators and lines in Central Queensland and associated under frequency load shedding event on 25 May 2021 involved the tripping of approximately 2,300 MW[76]. Therefore, such a significant interruption of mainland NEM load would likely take several hours to restore.

Moorabool contingency sensitivity studies

A fault on the MLTS – HGTS or MLTS – MOPS lines leading to a voltage disturbance and the subsequent loss of two Alcoa Portland (APD) potlines is reclassified as a credible contingency at present. In an over frequency event, a possible APD trip may exacerbate over frequency risks. However, in an under frequency 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[77]. The results of these sensitivities are summarised in the table below.

Table 20 Case results for South Australia separation at Moorabool with APD load tripping

Case	SA HIC + PEC (SA import +ve) (MW)	SA frequency nadir/peak (Hz)	QLD frequency nadir/peak (Hz)	QLD initial RoCoF (Hz/s)	NSW/VIC frequency nadir/peak (Hz)	SA OFGS generation tripped (MW)	Net UFLS tripped (MW)	SPS, EFCS, control scheme operation	Was the case stable? (Yes/No)
8	-900	52.5	51.2	0.66	48.7	98	VIC: 765 (17%) NSW: 986 (29%)	SAIT RAS, QNI distance protection	No, SA angular separation, QNI tripped to island QLD
9	-626	52.5	51.2	0.10	48.8	384	SA: 379 (22%) VIC: 765 (17%) NSW: 910 (23%)	QNI distance protection	No, SA angular separation, QNI tripped to island QLD

Sensitivity key findings

Sensitivity studies completed for South Australia export cases where the EAPT scheme did not operate, and tripping of APD loads occurred showed that frequency rose to higher values – 52.5 Hz compared to 52 Hz for Case 8 and Case 9.

[76] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-trip-of-multiple-generators-and-lines-in-qld-and-under-frequency-load-shedding.pdf?la=en.

[77] See Appendix 3.2 for more details on the APD sensitivities.

Note that AEMO has recommended investigating a new inter-tripping scheme in western Victoria to manage over frequency caused by a non-credible contingency and trip of APD load. Refer to Appendix A2 Table 2 row 1 for more details.

5.2.2 Risk 4b: Loy Yang contingency

The non-credible fault on the Loy Yang B unit 2 transformer followed by the failure of the No. 3 bus 500 kV circuit breaker was assessed assuming the maximum NER circuit breaker fail clearance time of 175 ms[78]. The results from this study are shown below in Table 21.

Table 21 Case results for the Loy Yang contingency

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)
320 - 1,390	47.9 - 49.64	49 - 51.46	0.05 - 1.21	0 (0%) - 3,018 (25%)	0 - 2,143

Key findings

The future studies of the loss of Loy Yang B and Valley Power units identified the following key findings in relation to the acceptance criteria:

- Consistent with the findings detailed in Section 5.2.1 for South Australia separation at Moorabool, the results show that this contingency has the potential to lead to QNI instability during Queensland export conditions.
- In seven of the cases studied, the QNI distance protection operated to trip QNI, resulting in synchronous separation of Queensland from the rest of the NEM.
  - In these cases, QNI was near the maximum export level from Queensland of 1,450 MW. 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 ranged from 580 MW to 1,390 MW.
- All other acceptance criteria were met for all the other cases studied.
  - In nine of the cases studied, UFLS operated to arrest the frequency nadir.
  - A large amount of mainland UFLS tripped for many of the cases studied – up to a total of more than 3,000 MW. Comparatively, the trip of multiple generators and lines in Central Queensland and associated under frequency load shedding event on 25 May 2021 involved the tripping of approximately 2,300 MW[79]. Therefore, such a significant interruption of mainland NEM load would likely have a significant impact on customer supply.

Detailed graphs and results for individual cases are included in Appendix A6.

[78] See Table S5.1a.2 in NER Chapter 5.

[79] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-trip-of-multiple-generators-and-lines-in-qld-and-under-frequency-load-shedding.pdf?la=en.

Other observations

Additional observations that do not impact the acceptance criteria are outlined below:

- For several daytime cases, a significant amount of DPV tripped on inverter settings due to the system frequency falling below 49 Hz following fault clearance.
  - The total amount of mainland NEM DPV tripped on inverter settings ranged from 0 MW to 2,143 MW.
  - Hence, this event highlights how the total contingency size will increase as DPV generation displaces large scale resources which are able to successfully ride through more severe frequency disturbances.
- In all the cases studied, none of the modelled SPSs or EFCSs operated.

5.2.3 Risk 4c: Millmerran contingency

The loss of two Millmerran generating units and regional DPV generation in Queensland due to a bus fault was assessed assuming the NER primary clearance time of 100 ms[80]. The case results for the Millmerran contingency are shown in Table 22 below.

Table 22 Case results for the Millmerran contingency

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)	NEM DPV tripped on inverter settings only (MW)
612 - 765	0 - 500	48.79 - 50.5	< 47 - 49.84	0.07-1.97	0 (0%) - 2,536 (87%)	0 - 3,480

Key findings

The future studies of loss of the Millmerran units identified the following key findings in relation to the acceptance criteria:

- Consistent with the findings detailed in Section 5.2.1 for South Australia separation at Moorabool, the results show that this contingency can lead to QNI instability during Queensland import conditions.
- In Cases 1, 3, 4 and 5, 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.
  - There was insufficient UFLS in Queensland to maintain the Queensland frequency above 47 Hz following separation. Therefore, this event highlights the importance of UFLS and the need to ensure adequate UFLS is maintained to prevent system collapse following major events.
  - The total contingency size of the tripped Millmerran generation ranged from 653 MW to 765 MW.
- All other acceptance criteria were met for all the other cases studied.
  - In four of the stable cases, UFLS successfully operated in the NEM to arrest the frequency.

[80] See Table S5.1a.2 in NER Chapter 5.

Detailed graphs and results for individual cases are included in Appendix A6.

Other observations

Additional observations that do not impact the acceptance criteria are outlined below:

- For several daytime cases, a significant amount of DPV was tripped on inverter settings due to the system frequency falling below 49 Hz following fault clearance.
  - The total amount of mainland NEM DPV tripped on inverter settings ranged from 0 MW to 3,480 MW.
  - Hence, this event also highlights how the total contingency size will increase as DPV generation displaces large scale resources which are able to successfully ride through more severe frequency disturbances.
- In all the cases studied, none of the modelled SPSs or EFCSs operated.

5.2.4 Sensitivity studies

Sensitivities completed with a reduced pre-contingent QNI flow indicate that a combined Queensland export level and contingency size that exceeds a total of 1,500 MW to 2,400 MW typically causes QNI to lose stability for Queensland export conditions. Similarly, for the Millmerran contingency, sensitivities completed reducing the pre-contingent QNI flow indicate that a combined Queensland import level and contingency size that exceeds a total of approximately 1,500 MW to 1,800 MW typically causes QNI to lose stability for Queensland import conditions. However, as detailed in Appendix A4, the simplified NEM model can capture QNI instability but cannot necessarily predict the exact QNI flow threshold at which instability occurs for a given contingency – the power swings on interconnectors and their angular stability predictions may be less conservative when compared with the full NEM OPDMS model. Therefore, these results are only indicative of how QNI can lose stability for different NEM contingencies.

Additional sensitivities were completed tripping load in Queensland (for Queensland import conditions) or New South Wales (for Queensland export conditions) following fault clearance. The results confirm that tripping load in New South Wales or Queensland, through the action of an SPS, for example, can prevent QNI from losing stability and Queensland separating from the rest of the mainland NEM. A summary of the results for these sensitivities is in Table 23, Table 24 and Table 25.

For certain dispatch conditions, the tripping of a similar amount of generation in Queensland was also found to reduce QNI flow and prevent instability. However, for cases where many synchronous generators in Queensland had significant FCAS raise headroom available, tripping Queensland generation led to significant primary frequency response action from the remaining generators and therefore failed to prevent QNI instability. Additionally, as detailed in Section 4.1.4, the Eraring and Liddell generator retirements were modelled in the future dispatch scenarios studied, so there was significantly less FCAS raise headroom available in New South Wales.

Table 23 Sensitivity case results for Risk 1 (Moorabool contingency)

Case	QNI flow (QLD export +ve) (MW)	Heywood + PEC flow (SA export +ve) (MW)	QNI flow reduction required (MW)	NSW/QLD load tripping required (MW)
1	-940	-1,300	100	100
7	1,353	75	500	700
8	1,302	900	500	800
9	1,412	626	300	300

Case	QNI flow (QLD export +ve) (MW)	Heywood + PEC flow (SA export +ve) (MW)	QNI flow reduction required (MW)	NSW/QLD load tripping required (MW)
10	1,392	499	600	800
12	1,365	1,261	600	80

Table 24 Sensitivity case results for Risk 2 (Loy Yang contingency)

Case	QNI flow (QLD export +ve) (MW)	Size of Loy Yang B + Valley Power Generation (MW)	QNI flow reduction required (MW)	Max stable contingency size + QNI flow (MW)	NSW load tripping required (MW)
6	1,366	640	200	1,806	500
7	1,353	580	400	1,534	400
8	1,302	1,390	500	2,193	850
9	1,412	1,027	600	1,839	1000
10	1,392	640	400	1,632	500
11	1,400	1,154	200	2,354	300

Table 25 Sensitivity case results for Risk 3 (Millmerran contingency)

Case	QNI flow (QLD export +ve) (MW)	Millmerran size (MW)	Tripped DPV amount (9%) (MW)	QNI flow reduction	Max stable contingency size + QNI flow (MW)	QLD load tripping required (MW)
1	940	671	201	300	1,512	300
3	940	665	103	200	1,508	300
4	940	654	500	300	1,794	500
5	940	765	235	300	1,640	400

5.2.5 Conclusions

Non-credible contingency events leading to QNI instability and Queensland separation

- The historical and future studies from the 2022 PSFRR, as well as the additional future studies completed for the 2023 GPSRR, show that QNI can become unstable following a range of different non-credible contingencies across the mainland NEM, with the potential for subsequent power system events to occur[81]. These non-credible contingencies include:
  - Loss of the Victoria – New South Wales Interconnector (VNI) (2022 PFSRR).
  - Separation of South Australia through loss of Heywood – South East 275 kV lines (2022 PFSRR).
  - South Australia separation at MLTS (2022 PFSRR and 2023 GPSRR).
  - Loss of Columboola – Western Downs 275 kV lines resulting in large loss of load (2022 PFSRR).
  - Loss of both 275 kV lines between Calvale and Halys with upgraded Central Queensland (CQ) and South Queensland (SQ) SPS (2022 PSFRR).
  - Fault on Loy Yang B unit 2 transformer with No. 3 500 kV bus circuit breaker failure (2023 GPSRR).

[81] By inference, as observed during actual power system events.

  - Large amount of generation and DPV loss in Southern Queensland (2023 GPSRR).
- Therefore, the results from the 2023 GPSRR future studies further support the need for remedial measures to prevent the loss of QNI and the separation of Queensland.
  - AEMO has concluded that there is an existing and increasing risk of QNI instability following a range of non-credible contingencies and recommends that Powerlink and Transgrid investigate, design and implement an appropriate SPS under NER S5.1.8 to mitigate this risk.
    - As detailed in Section 5.2.4, studies undertaken by AEMO show that an SPS that trips load for an under frequency event in New South Wales when QNI is flowing in a southerly direction, or in Queensland when QNI is flowing in a northerly direction may be effective at preventing QNI from losing stability and Queensland separating from the rest of the mainland NEM.

Recommendation 2

Given the potentially significant impact Risk 4 could have on the NEM, AEMO recommends that Powerlink and Transgrid, investigate, design and implement a special protection scheme (SPS) under NER S5.1.8 in order to mitigate the risk of QNI instability and synchronous separation of Queensland following a range of non-credible contingencies. If a scheme is found viable, AEMO recommends this scheme be commissioned as soon as possible, and no later than June 2025.

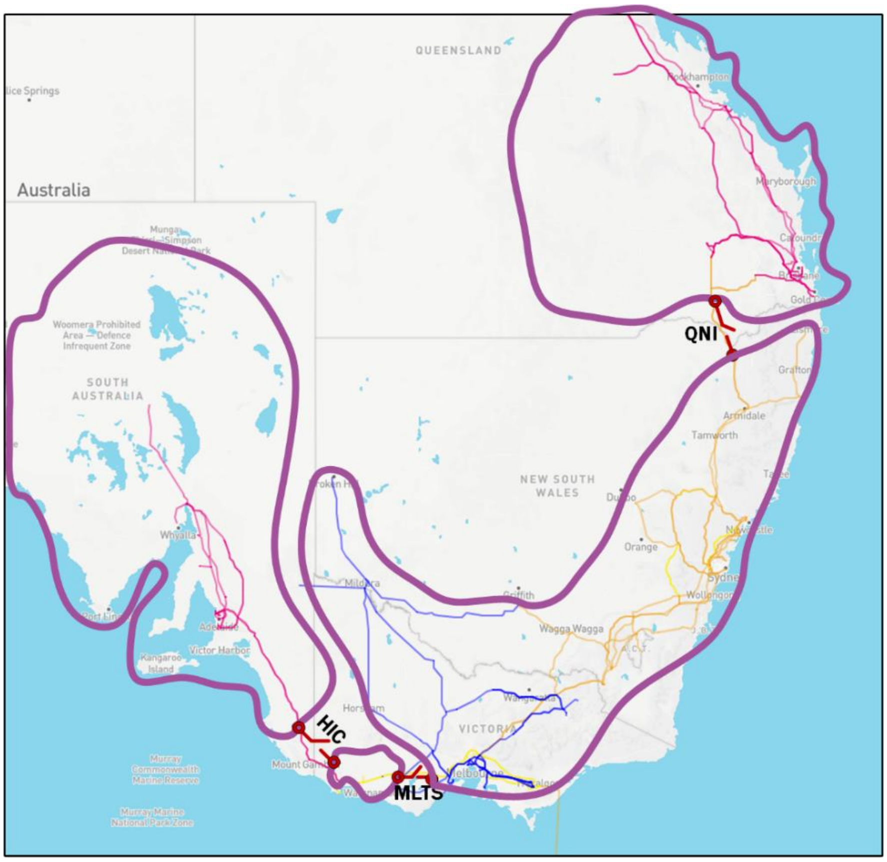
SAIT RAS and QNI instability

- Consistent with what was observed in the 2022 PSFRR, studies by AEMO highlight that for scenarios where loss of the MLTS lines could result in the SAIT RAS actions not being able to prevent a large power swing on PEC, this could lead to the tripping of PEC and the synchronous separation of South Australia, as well as the tripping of QNI and the synchronous separation of Queensland. Therefore, the results show that Moorabool separation can possibly cause loss of stability on QNI, which could be exacerbated by the actions of existing SPSs within Victoria and the SAIT RAS due to the total generation disconnected.
  - Figure 12 shows the separation of the mainland NEM into four islanded areas – Queensland, South Australia (separated at Heywood following EAPT operation), area between Heywood and Moorabool (not a viable island) and the rest of New South Wales and Victoria – which could occur following this contingency.
- AEMO, AEMO Victorian Planning (AVP), ElectraNet and Transgrid should continue collaborating as part of the PEC System Integration Steering Committee (SISC) to ensure that the SAIT RAS operates effectively in conjunction with existing NEM system protection and generation tripping schemes (see Appendix A3.2 for relevant schemes), as well as any future QNI SPS and other protection schemes.
- Additionally, this may warrant a Protected Event (or jurisdictional dispensation) to enable operational measures to mitigate residual risks.

Recommendation 3

Given the potential for Moorabool contingency events to result in separation of the mainland NEM into four islanded areas – Queensland, South Australia separated at Heywood following EAPT operation, area between Heywood and Moorabool (not a viable island) and the rest of New South Wales and Victoria – AEMO recommends that AEMO, AEMO Victorian Planning (AVP), ElectraNet and Transgrid continue collaborating as part of the PEC System Integration Steering Committee (SISC) to ensure that the SAIT RAS operates effectively in conjunction with existing NEM system protection and generation tripping schemes (see Appendix A3.2 for relevant schemes), as well as any future QNI SPS and other protection schemes.

Figure 12 Risk 4a: Moorabool contingency (with EAPT operation), NEM separates into four islands



Queensland stability following separation

The separation of Queensland following the non-credible loss of QNI was studied in detail as part of the 2022 PSFRR. As such, the stability of Queensland post-separation was not the primary focus of the future studies completed for the 2023 GPSRR. The implementation of the following 2022 PSFRR recommendations is ongoing, and is essential to ensure the stability of Queensland following separation:

- An OFGS scheme for Queensland is implemented to manage over frequency during separation.
- Remedial actions are taken in Queensland to restore UFLS load.

5.2.6 QNI stability risk management options filtering

The results from the 2023 GPSRR future studies further support the need for remedial measures to prevent the loss of QNI and the separation of Queensland. The screening assessment of the possible solutions for the risk associated with mainland NEM non-credible contingency events leading to QNI instability is summarised in Table 26 below.

Table 26 Option screening assessment for solutions for non-credible events leading to QNI instability

Solution option	Short description	Advantages	Disadvantages	Timing	Overall rating (0-5)
1	Post-contingent QNI SPS	Low-cost solution, cost significantly less than risk cost	Increases system complexity	3-5 years	5
2	Do nothing	Zero-cost	Does not mitigate risk	N/A	2
3	Queensland protected event	Reduces risk pre-contingency, non-network solution	QNI flow would likely be constrained the majority of the time – high cost, yearly cost likely exceeds risk cost[A]	<3 years	3
4	Major network augmentation	Eliminates risk pre-contingency, increases system resilience	Very high cost, cost would likely exceed risk cost, implementation time longer than other solutions	5+ years	1

A. See Section 7.2 for details of AEMO's assessment of the QNI protected events potential market benefit.

5.2.7 Risk assessment

Based on the studies of contingencies leading to QNI instability with future operating conditions completed for the 2023 GPSRR as well as the solution option screening assessment detailed in Table 26, AEMO identified an SPS implemented under NER S5.1.8 as the timeliest and most economically feasible solution to mitigate this risk.

In order to demonstrate the economic feasibility of this solution, AEMO estimated the cost of this risk and compared this with the anticipated cost of an SPS. To estimate the cost of this risk, the risk assessment methodology detailed in Appendix A3 was applied as detailed in the following report sections.

Estimation of likelihood of risk exposure (P_e) and probability of non-credible contingency event (P_c)

To estimate the likelihood of risk exposure (P_e), the average percentage of time that dispatch conditions are such that one of the NEM non-credible contingencies studied as part of the 2022 PSFRR and 2023 GPSRR could lead to QNI instability was calculated based on the ISP FY 2027-28 forecasting data. The products of the likelihood of risk exposure and the probability of the non-credible contingency for the different contingencies that could lead to QNI instability can be summated if they are mutually exclusive[82].

It is important to note for the calculation of the P_e and P_c terms that, as detailed in Appendix A3, there are likely many non-credible contingencies across the NEM that could lead to QNI instability that were not studied in the 2022 PSFRR or 2023 GPSRR.

Therefore, it was estimated that the average rate of significant non-credible generation contingencies south of Queensland that could lead to QNI instability for Queensland export conditions occurring is approximately one per

[82] Mutually exclusive is a statistical term describing two or more events that cannot happen simultaneously.

year. This rate was determined based on historical events. Over the past five years, between 2018 and 2023, there have been over seven events that have either resulted in or had the potential to result in a large loss of generation south of Queensland[83]. Based on the ISP FY 2027-28 dispatch data, the average percentage of time that Queensland export exceeds 1,300 MW is 6%.

It was estimated that the average rate of significant non-credible generation contingencies in Queensland that could lead to QNI instability for Queensland import conditions occurring is approximately 0.5 per year. This rate was determined based on historical events. Over the past five years, between 2018 and 2023, there have been over three events that have either resulted in or had the potential to result in a large loss generation in Queensland[84]. Based on the ISP FY 2027-28 dispatch data, the average percentage of time that Queensland import exceeds 900 MW is 11%.

Since the periods when Queensland is importing or exporting are mutually exclusive, the products of the likelihood of risk exposure and probability of non-credible contingency event values can be summated as follows:

$$P_{total} = \left(P_{e,QNI\ export} \times P_{c,QNI\ export}\right) + \left(P_{e,QNI\ import} \times P_{c,QNI\ import}\right) = 1 \times 0.06 + 0.5 \times 0.11 = 0.115$$

Estimation of loss of load due to non-credible contingency event (L) and time to restore interrupted loads (T)

A non-credible contingency, such as the loss of an interconnector, leading to instability on QNI and the separation of Queensland, is a severe cascading failure. There is therefore little certainty about what further cascading failures could occur or what plants' performance would be following such a severe event. As a result, it is difficult to calculate the average loss of load as a result of such an event.

A recent example of a severe event involving multiple cascading failures was the trip of multiple generators and lines in Queensland and associated under frequency load shedding on 25 May 2021, during which a series of failures led to the loss of a significant amount of load in Queensland[85].

Hence, to determine the effective loss of load for non-credible events leading to QNI instability and Queensland separation, AEMO estimated the probability of a system or region black condition following such an event and calculated the appropriate loss of system load and time to restore values accordingly.

It was estimated that the probability of a mainland NEM or Queensland system black condition[86] following a non-credible contingency causing QNI instability and the separation of Queensland is:

$$P_{sys\ black} \approx 0.01$$

The average system load lost was then estimated as the average mainland NEM operational load, based on the ISP FY 2027-28 dispatch data:

$$L\ (MW) = 4819\ to\ 31600$$

[83] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

[84] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

[85] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-trip-of-multiple-generators-and-lines-in-qld-and-under-frequency-load-shedding.pdf?la=en.

[86] See https://www.aemc.gov.au/energy-system/electricity/electricity-system/security.

In accordance with AEMO's past operational experience, the time to restore system load following a system or regional black condition was estimated as approximately:

$$T(hours) \approx 4\ to\ 8$$

Estimation of value of unserved energy during interruption (VCR)

The value of unserved energy was published by the Australian Energy Regulator (AER) in 2019 as $43.23 per kilowatt-hour (kWh)[87]. This value was adjusted for FY 2024-25 based on the consumer price index (CPI) to be used for these risk cost calculations:

$$VCR(\$/kWh) = 50.42$$

Calculation of annual risk cost

Therefore, based on the values specified in the sections above, AEMO estimated the total risk cost for non-credible contingencies in the NEM leading to QNI instability and the separation of Queensland to be:

$$\begin{aligned} Non - credible\ event\ risk\ cost\ (\$/year) &= P_{total} \times P_{sys\ black} \times L \times T \times VCR \\ &= 0.115 \times 0.01 \times (4819\ to\ 31600) \times (4\ to\ 8) \times 50.42 \times 1000 \\ &= 1{,}120{,}000\ to\ 14{,}660{,}000(\$/year) \end{aligned}$$

Note that this risk cost does not include the cost associated with the load shedding/UFLS action that would occur in Queensland or the rest of the mainland NEM if a cascading failure or a system black condition does not occur following QNI instability. This cost is additional to the risk cost estimated above for non-credible events leading to QNI instability. Similarly, the added risk cost associated with scenarios where there is a regional Queensland system black condition, but the remaining mainland NEM remains intact following separation, or vice versa, is also not included.

Economic feasibility of QNI SPS

Based on previous similar projects, the anticipated cost of a QNI SPS was estimated by AEMO to be $2-3 million.

Therefore, AEMO has determined that the mitigation option of a QNI SPS is economically feasible based on the cost of the SPS compared to the estimated annual risk cost, as detailed in Appendix A3. However, it is important to note that a QNI SPS would reduce the estimated ongoing risk cost significantly but would not eliminate it completely.

[87] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability.

6 Review of risk management measures

6.1 Generator over frequency protection co-ordination strategy

To improve the power system's response to over frequency events, AEMO is developing an updated strategy for the overall co-ordination of generator over frequency protection settings. The adopted approach has minimal associated cost as it will be implemented in the existing connection process under NER S5.2.5.8. The strategy involves AEMO requesting staggered over frequency protection settings for all new connections to the NEM[88] and can be implemented under existing NER frameworks[89].

AEMO expects the updated generator over frequency protection strategy to:

- Introduce a staggered and proportional response to over frequency events.
- Leverage existing PFR settings and a staggering of other over frequency protection settings (where appropriate).
- Support existing and proposed OFGS schemes.
- Decrease the risk that a sustained high frequency event causes unco-ordinated multiple generator disconnections followed by a large drop in frequency, UFLS operation and possible system black out.

AEMO plans to adopt its updated generator over frequency protection co-ordination strategy by Q3 2023.

This change helps address issues identified following a power system event that occurred on 25 August 2018[90].

Recommendation 8

AEMO to finalise the development of an updated strategy for the overall co-ordination of generator over frequency protection settings.

6.2 OFGS review

OFGS schemes operate to trip generators for over frequency events. At present, OFGS schemes are in operation in Tasmania, South Australia and Western Victoria. The following improvements are being pursued or planned to improve OFGS operation in different regions:

- South Australia and Western Victoria OFGS – implementation of updated South Australia OFGS settings is being progressed with ElectraNet and subject to successful testing and commissioning. This is anticipated to be completed in Q3 2023. A review of Western Victoria OFGS has been completed and there are multiple

[88] AEMO expects generators will be able to achieve these staggered protection settings without the need for any additional protection systems, with protection settings being outlined in each generator's GPS and being applied in line with existing processes.

[89] Under NER S5.2.5.8, AEMO can nominate a frequency (above the upper limit of the operational frequency tolerance band) and associated time delay after which a generator must automatically reduce its output by at least half within 3 seconds, or disconnect within 1 second.

[90] See 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.

options to improve the OFGS scheme. AEMO is in the process of consulting with relevant parties on these improvement options. The anticipated timing is eight months (Q1 2024), subject to the final design.

- Queensland OFGS – AEMO has identified a benefit of implementing an OFGS in Queensland to help mitigate over frequency events, such as those due to QNI tripping. AEMO is working on the design in consultation with Powerlink, which is planned for completion by Q4 2023. Following the detailed design, AEMO will cooperate with Powerlink as needed on the procurement, implementation, and commissioning schedule.
- AEMO will continue to assess the potential need for OFGS in New South Wales and Victoria (east of Moorabool).

6.3 Emergency under frequency management

UFLS is a last resort "safety net", designed to prevent black system events when severe (non-credible) generation contingencies occur. It involves the automatic disconnection of load circuits to rebalance supply and demand in less than one second.

Increasing levels of generation from DPV are reducing the load on UFLS circuits, reducing the effectiveness of UFLS. With even further growth in DPV generation, UFLS circuits can operate in reverse flows, which means that in the absence of intervention, UFLS relays will act to disconnect circuits that are net generators (rather than net loads), exacerbating the supply demand imbalance when they activate following an under frequency event. More information can be found in AEMO reports to NSPs advising on the impacts of DER on net UFLS load in Victoria[91], New South Wales[92] and Queensland[93], and in previous PSFRRs[94,95,96].

Table 27 summarises key emergency under frequency management initiatives underway.

Table 27 Summary of UFLS remediation projects

Region	Project	Lead	Status
NEM	Determination of Emergency Under Frequency Response (EUFR) requirements for low demand periods	AEMO	• AEMO developing methodology. • Application of methodology to determine EUFR requirements for South Australia, followed by other regions (see further detail below).
	Improved UFLS models	AEMO	• Improved integration of UFLS into AEMO's root mean squared (RMS) and EMT power system models in progress. • Improved modelling is necessary to facilitate ongoing work to design and update UFLS settings under emerging novel power system conditions.

91 AEMO (August 2021) *Phase 1 UFLS Review: Victoria,* https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.

92 AEMO (December 2021) *Phase 1 UFLS Review: New South Wales,* https://aemo.com.au/-/media/files/initiatives/der/2022/new-south-wales-ufls-scheme.pdf?la=en&hash=D8E106C09B66F9EAC4C6601E068784F0.

93 AEMO (December 2021) *Phase 1 UFLS Review: Queensland,* https://aemo.com.au/-/media/files/initiatives/der/2022/queensland-ufls-scheme.pdf?la=en&hash=A451A3AEA814BFBB16CE0AAD185CB7FE.

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

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

96 AEMO (July 2022) Power System Frequency Risk Review, Final Report, Section 3.3, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en&hash=79BE593AE07E51B7E8129210D45840A6.

Region	Project	Lead	Status
SA	Dynamic arming[A] of UFLS relays (blocks UFLS activation if circuit is in reverse flow)	SA NSPs	• AER approved SA Power Networks cost pass-through application[B]. • SA Power Networks implementation is under way (see further detail below), target completion: 2024.
	SA Power Networks Expressions of Interest (EOI) for Emergency Under Frequency Response (EUFR) service procurement	SA NSPs	• Responses from EOI not economically viable. • Exploration of alternate pathways to procure additional EUFR ongoing.
	Real time SCADA feed of UFLS load in each band	SA NSPs	• Real-time SCADA feed established for total SA UFLS load. • SA Power Networks is updating capability to provide visibility of load in individual UFLS bands (target completion: 2024).
	Expansion of delayed UFLS scheme	AEMO, SA NSPs	• AEMO advice provided to SA Power Networks to expand delayed UFLS[C]. • SA Power Networks identification of circuits and implementation underway (target completion: 2024).
VIC	AEMO advice to NSPs	AEMO	• AEMO report provided to NSPs identifying declining load in UFLS due to DPV, and projecting UFLS net load to reach as low as 12% of underlying demand in some periods by late 2023[D]. Recommended that NSPs explore rectification options. • Update delivered to NSPs in 2023, identifying continuing trend in decline[E].
	Real time SCADA feed of UFLS load in each band	VIC NSPs	• AEMO has established a method for compiling VIC UFLS data from TUoS metering (for post-hoc analysis). • Further NSP actions required to establish real-time visibility.
	Addressing large wind/solar farms behind UFLS relays	VIC NSPs	• AEMO report identified several UFLS circuits in significant reverse flows due to large wind and solar farms connected behind UFLS relays[F]. Recommended that NSPs seek rectification. • AusNet Transmission has developed a rectification proposal. AER approval required to proceed.
	Connections process updates to account for UFLS	VIC NSPs	• AEMO report recommended that NSPs update their connections processes to minimise detrimental UFLS impacts for new generator connections[F]. • Under consideration via the Victorian Electricity Emergency Committee (VEEC).
	Adding new loads to UFLS	VIC NSPs	• AusNet Transmission has conducted an audit of VIC UFLS and identified “Stage 1” rectification actions, including circuits to be removed from the UFLS (in frequent reverse flows), and circuits to be added to UFLS. • Proposed Stage 1 actions have been reviewed and approved by VEEC and VIC DNSPs. • NSPs progressing AER approval.
	Feasibility study for UFLS provided by Advanced Metering Infrastructure (AMI)	AEMO	• The feasibility of different options for UFLS remediation, including UFLS at customer AMI, has been analysed using case studies of several archetypal sub-transmission loops. This approach does appear to have technical merit and long term potential, but many areas requiring further investigation were identified. • AEMO has published a short report on the findings to inform further NSP investigation[E].
NSW	AEMO advice to NSPs	AEMO	• AEMO report provided to NSPs identifying declining load in UFLS due to DPV[F]. Recommended NSPs explore rectification options.
	NSP progress on UFLS remediation	NSW NSPs	• NSPs conducting an audit of NSW UFLS identifying short term remediation actions. • NSPs identify metering uplifts required, especially to identify UFLS circuits in reverse power flow. • Initial implementation and testing of dynamic arming on limited circuits.
QLD	AEMO advice to NSPs	AEMO	• AEMO report provided to NSPs identifying declining load in UFLS due to DPV[H]. Recommended NSPs explore rectification options.
	NSP progress on UFLS remediation	QLD NSPs	• NSPs auditing UFLS scheme, identifying areas of improvement.

Region	Project	Lead	Status
			• NSPs identify metering uplifts required, especially to identify UFLS circuits in reverse power flow. • Energy Queensland developing dashboard for real time visibility of UFLS load.

A. AEMO (May 2021) *South Australian Under Frequency Load Shedding – Dynamic Arming*, https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf?la=en&hash=C82E09BBF2A112ED014F3436A18D836C.
B. AER (2022) *SA Power Networks – Cost pass through – Emergency standards 2021-22*, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-pass-throughs/sa-power-networks-cost-pass-through-emergency-standards-2021%E2%80%9322.
C. 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.
D. AEMO (August 2021) *Phase 1 UFLS Review: Victoria*, https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.
E. AEMO (May 2023) *Victoria: UFLS load assessment update*, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2023-05-25-vic-ufls-2022-review.pdf?la=en&hash=CFDBA2D60117E8E7FE452B2C2F468B3B
F. AEMO (August 2021) *Phase 1 UFLS Review: Victoria*, (Section 3.5, Section 4.1), https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.
G. AEMO (December 2021) *Phase 1 UFLS Review: New South Wales*, https://aemo.com.au/-/media/files/initiatives/der/2022/new-south-wales-ufls-scheme.pdf?la=en&hash=D8E106C09B66F9EAC4C6601E068784F0.
H. AEMO (December 2021) *Phase 1 UFLS Review: Queensland*, https://aemo.com.au/-/media/files/initiatives/der/2022/queensland-ufls-scheme.pdf?la=en&hash=A451A3AEA814BFBB16CE0AAD185CB7FE.

South Australia – Dynamic UFLS arming

Dynamic arming of UFLS in South Australia commenced rollout in October 2022. The project will recover an estimated 385 MW[97] to the UFLS scheme in South Australia by the time of completion in 2024. By March 2023, the initiative has recovered an estimated 72 MW of net load to the UFLS scheme. The current plan for 2023 will see approximately 260 MW of net load recovered.

Victoria – UFLS load in historical and projected periods

AEMO updated analysis of UFLS load in Victoria, accounting for continuing growth in DPV during 2021-2023[98]. Key findings from the update are as follows:

- Annual minimum total net load in the Victorian UFLS scheme has decreased from close to 2 gigawatts (GW) in 2018 to 1.2 GW in 2022.
- This trend is projected to continue as the installation of DPV continues, with minimum total UFLS load in Victoria projected to reach close to 870 MW by late 2025, and 576 MW by late 2026 (based on the ISP *Step Change* scenario forecast growth in DPV and change in underlying demand).
- Net UFLS load in Victoria has decreased from a minimum of 45% of underlying demand in 2018, to a minimum of 18% of underlying demand in 2022.

The continued growth in DPV is also leading to an increase in UFLS sub-transmission loops experiencing reverse flows. Reverse power flows are detrimental for UFLS operation because they offset the intended outcome of UFLS activation (disconnecting circuits that are net generators, rather than net loads), and mean that more customers must be disconnected to achieve the same arrest in a frequency decline.

Figure 13 shows the percentage of the year that various (anonymised) sub-transmission loops in Victoria are now in reverse flow, and Figure 14 shows the maximum reverse power flow from these sub-transmission loops.

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

[98] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2023-05-25-vic-ufls-2022-review.pdf?la=en&hash=CFDBA2D60117E8E7FE452B2C2F468B3B

Figure 13 Percentage of time in reverse flow for anonymised sub-transmission loops in the Victorian UFLS scheme

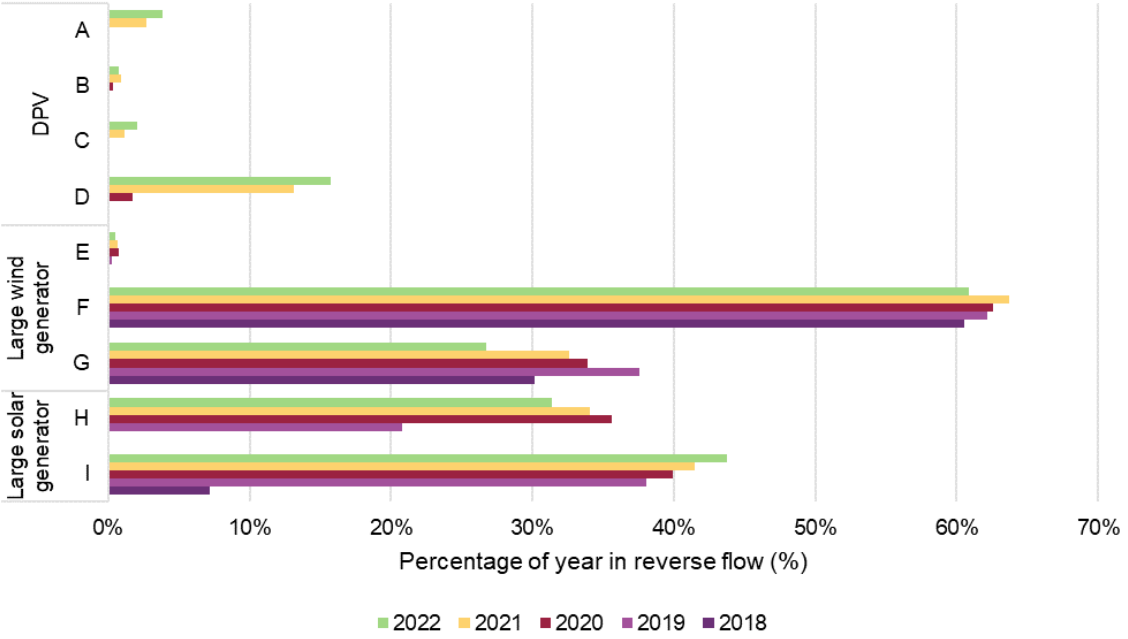
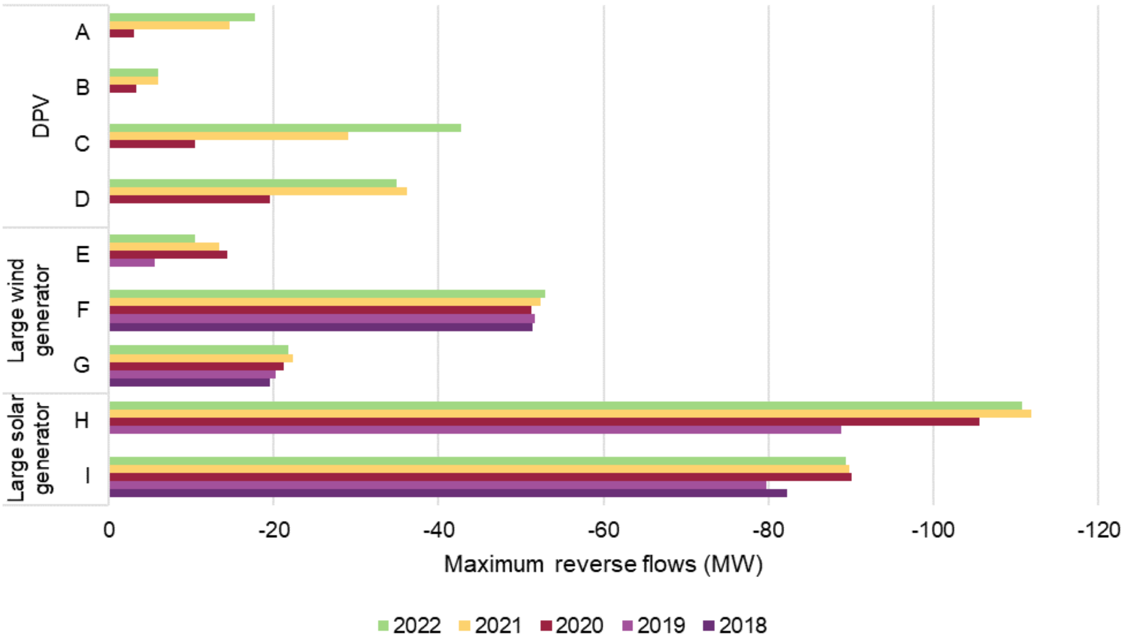


Figure 14 Maximum reverse power flows from anonymised sub-transmission loops in the Victorian UFLS scheme



Key findings are as follows:

- Several sub-transmission loops were identified to have large wind and solar generators located on UFLS circuits (such that they will be disconnected when UFLS relays operate). This is detrimental to UFLS functionality. These loops are in reverse flow up to 60% of the time, and experience reverse power flows as large as 115 MW.

- Sub-transmission loops were also identified with high levels of DPV. In 2022, these loops experienced reverse flows as high as 42 MW and were in reverse flows for up to 15% of the year.
- 26 sub-transmission loops on the UFLS scheme that were not in reverse flow in 2018 are now exhibiting reverse power flows in 2022.

AEMO has recommended that Victorian NSPs investigate options to remediate UFLS, particularly addressing reverse flows. Dynamic arming of UFLS relays (automatically blocking of relay operation when the circuit is in reverse flows) should be explored.

Exploring feasibility of UFLS from advanced metering infrastructure (AMI)

AEMO has conducted analysis to explore the feasibility of several possible remediation approaches for UFLS in Victoria:

- Option 1 – implement dynamic arming (automatic blocking of UFLS relay action when the circuit is in reverse lows) at the existing UFLS relay location (66 kV sub-transmission level), to prevent shedding of sub-transmission loops in reverse flows.
- Option 2 – move UFLS relays from 66 kV sub-transmission level to 22 kV feeder level, and implement dynamic arming, to provide more granularity and allow selective shedding only of 22 kV feeders that are net loads (while 22 kV circuits that are in reverse flows remain connected).
- Option 3 – implement UFLS functionality via AMI at the individual customer level, allowing selective shedding only of customer sites that are net loads (while individual customers that are net exporting remain connected). Note that this analysis only covered the technical feasibility of utilising AMI for load shedding, and regulatory changes would also be required to enable this, with further consideration to be given to the end-to-end impact of those changes.

The analysis was conducted for four case studies of archetypal loops: a sub-transmission loop with a large solar farm; a loop with large wind farms; a loop with a high level of commercial load; and a loop with mainly residential customers. For each of these case studies, the different options to remediate UFLS load were investigated using actual load data from 2021 at the 66 kV sub-transmission level, the 22 kV feeder level, and aggregated from residential customer AMI.

Key findings were as follows:

- All options explored showed merit in different situations, and different options will likely be optimal in different locations.
- Utilising customer AMI appears to be a promising option which could restore a large proportion of UFLS load in the middle of the day for sub-transmission loops with a high proportion of residential customer load, and high levels of reverse flow due to DPV. A number of important feasibility issues remain to be explored, including:
  - The robustness of the AMI response in the fast response times required for UFLS (typically requiring detection and response to a severe under frequency event within 200-300 ms). This will require confirmation that mal-operation/false-triggering rates are suitably low, while ensuring a robust response in these rapid timeframes when required.
  - The impacts on distribution feeder voltages from selectively shedding net-load customers while leaving net-exporting customers connected. In particular, it needs to be determined whether load tripping could result in a subsequent voltage rise that could lead to DPV tripping on instantaneous over-voltage settings.

   - The feasibility and costs of rolling out this capability across existing and/or new AMI, and how this implementation process might occur.
- This early feasibility study suggests that there is merit in NSPs exploring the AMI option further.

Emergency under frequency response requirement in high DER periods

AEMO is currently undertaking analysis and modelling to evaluate risks associated with inadequate emergency under frequency response (EUFR) in low demand periods with high distributed generation. EUFR could be delivered by traditional UFLS, or fast frequency response (FFR) from BESSs or other IBR, or any other rapid frequency response that can arrest frequency decline in severe non-credible under frequency contingency events.

The aim is to understand plausible contingencies that could occur in these low demand periods, and determine how they can be adequately managed.

The methodology consists of:

- Developing a set of plausible non-credible contingency events that could occur in low demand periods.
- Modelling these contingency events across a wide variety of operating conditions with current and projected UFLS capability.
- Identifying failed cases and optimising the additional battery response required to achieve an acceptable result (avoiding cascading failure).
- Determining the EUFR required (UFLS + battery response) under varying operating conditions.

The initial focus of the studies is to determine EUFR requirements in the South Australia power system. The methodology will then be extended to other NEM regions.

6.4 Future UFLS projects

AEMO's review of UFLS to date has identified a number of areas where further UFLS review or rectification should be explored, as summarised in Table 28.

Table 28 Summary of future UFLS rectification areas

Area	Region	Notes
Rebalancing and optimisation of UFLS settings	SA	• Re-distribute large amount of load assigned to the lowest UFLS bands (leads to non-optimal UFLS functioning and can result in overshoot following large contingencies). • Review and optimisation of settings following dynamic arming upgrades.
	VIC	• Review UFLS settings for large industrial loads (accounting for some known changes in those loads over time). • Review coordination of UFLS with other regions (studies suggest VIC UFLS over-delivers response compared with other regions, which can lead to power swings on interconnectors). • Investigate possible over frequency over-shoot outcomes.
	NSW	• Consolidate large number of UFLS settings bands for simpler coordination (review identified 121 different UFLS bands with different frequency/time delay settings)
	QLD	• Review of the QLD UFLS QNI inhibit scheme (inhibits operation of some UFLS bands under certain power system conditions). Review of ongoing scheme appropriateness and optimal settings is required.

Area	Region	Notes
		• Review of UFLS settings for large industrial loads, especially given addition of several new loads to the scheme. • Review coordination of UFLS with other regions (studies suggest the QLD UFLS response under-delivers compared with other regions, which can lead to power swings on interconnectors).
Real time SCADA feed of UFLS load in each band	VIC	• Current capability allows AEMO to extract UFLS data post hoc. • Real-time visibility should be explored to support improved real-time decision-making in low demand periods.
	NSW	• Capability to measure reverse power flow on circuits required. Likely requires significant uplift of infrastructure. • Real-time visibility should be explored to support improved real-time decision-making in low demand periods.
	QLD	• NSPs currently working on a dashboard to provide real time visibility of UFLS. • Likely requires uplift of infrastructure to facilitate (for example, metering improvements to identify reverse flows accurately).
UFLS regulatory frameworks	All	May be a need for clarification of regulatory frameworks, especially in periods where EUFR is no longer feasible via traditional UFLS. This might need to consider: • Process for determining “adequate” levels of EUFR. • Consideration of other equivalent technologies that may be able to contribute to the desired response. • Roles and responsibilities on delivering adequate EUFR (for example, where there are multiple NSPs in a region, or split responsibilities between TNSPs and DNSPs).

6.5 Emergency reserves and services

In the February 2023 Update to the 2022 ESOO, AEMO forecast that reliability is expected to remain within the interim reliability measure until the end of 2024-25, however overall AEMO advised that there is an urgent need for additional generation commitments to occur over the next 10 years[99].

AEMO has identified the following NEM reliability risks for the coming summer and future years:

- Potential for higher peak demands, for example due to unexpected severe weather.
- Increased forced generator outages (including fuel availability issues or equipment breakdown).
- Increased unplanned outages of transmission elements.
- Decreases in inter-regional peak transfer capacity (including abnormal system conditions).
- Delays to the commissioning of new generation, transmission, or storage capacity.
- Operational impacts of extreme temperature on all generation technologies that may reduce output to below the rated generator capacity.

In recent years, some jurisdictions have procured emergency reserves to help address emerging risks or issues. Additionally, where market mechanisms have not sufficiently alleviated a reserve shortfall in time to avoid intervention, AEMO has on occasion exercised its Reliability and Emergency Reserve Trader (RERT) function.

There are advantages and disadvantages associated with jurisdictions procuring emergency reserves, including lead time, cost of contracting, cost of use, market impacts, and availability. For example, it takes significant

[99] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/february-2023-update-to-the-2022-esoo.pdf?la=en.

planning, time, and resources for a jurisdiction to procure emergency reserves. However, it can be designed with unique requirements and bespoke conditions which may not be possible under the RERT framework.

Jurisdictions and NSPs have procured emergency reserves in three NEM regions on recent occasions (and engaged with AEMO regarding the potential to do so in other instances). In each case, these projects have been initiated at short notice (under 12 months), requiring expedited review of factors such as:

- Site and land availability (including zoning).
- Contracting with third parties to design, procure and deliver the required infrastructure.
- Access to fuel supplies (such as gas supply, diesel storage).
- Availability of long lead items (such as high voltage transformers).
- Availability of generating assets.
- Availability of suitable distribution or transmission connection points.
- Potential constraints on the power system at the time generation is required.
- Augmentation of the power system (for example, protection).
- Environmental constraints.
- Community acceptance.
- Integration including control system settings, protection and commissioning.
- Capacity of individual sites, considering the above factors.
- Power system outage requirements needed associated with relevant upgrades and connection.
- Risks associated with procuring equipment and/or commencing construction (to minimise project timelines) in advance of finalising technical requirements.

Emergency generation reserves have been procured by participating jurisdictions on the following occasions:

- Tasmania:
  - During 2015-16, the combined impact of two extreme events (record low rainfall during spring, and the Basslink interconnector being out of service) resulted in Hydro Tasmania's water storage levels falling to historically low levels.
  - This security event was managed through the implementation of an Energy Supply Plan[100], which included using gas generation at the Tamar Valley Power Station (including the recommissioning of the combined cycle gas turbine (CCGT)), wind generation, commercially agreed demand reductions from some major industrial customers and the rapid commissioning of more than 200 MW of temporary diesel generation capacity. These measures partially offset the need for hydro-electric generation and, therefore, slowed the rate of decline in water storages.
- South Australia:
  - In 2017, as part of the South Australian government's Energy Plan, the Temporary Generation South and Temporary Generation North power stations in Lonsdale, which comprised open cycle gas turbines with a

[100] See https://www.stategrowth.tas.gov.au/__data/assets/pdf_file/0003/142689/Tasmanian_Energy_Security_Taskforce_-_Interim_Report.PDF.

total capacity of 120 MW and 154 MW, were purchased by the Government of South Australia[101]. The generating units were procured to be used in emergency situations during summer 2017-18 if extreme conditions created a supply shortfall that could not be met in other ways.

  - The South Australian Energy Plan also delivered the Hornsdale Power Reserve, a utility-scale 100 MW/129 megawatt hour (MWh) battery, which was operational by December 2017. Additionally, a 50 MW/64.5 MWh expansion of the Hornsdale Power Reserve to give a total capacity of 150 MW was completed in September 2020[102]. The full 150 MW BESS was also upgraded to include Tesla's Virtual Machine Mode, enabling the battery to provide inertia support services to the electricity grid.

- Victoria:
  - AEMO forecast that, during the 2017-18 summer, there would be an electricity shortage in Victoria and temporary standby emergency power supply would be needed to help meet Victoria's power needs due to the extreme summer conditions[103].
  - To address the forecast electricity deficit, 105 diesel-fired generators with a total capacity of 110 MW were temporarily installed in the Latrobe Valley[104].

It is recommended that jurisdictions develop contingency plans that identify and scope potential locations to install emergency generation.

In addition to contingency planning for emergency reserves, jurisdictions could also consider planning for availability of system security services for unexpected conditions, such as system strength and voltage control. For example, prolonged forced outages of existing coal and gas plants may result in a deficit of available services for N-1 security and power system resilience. The potential lead times to replace services with other equipment such as synchronous condensers and grid forming inverters could be significant.

It is therefore recommended that system security contingency plans are developed by jurisdictions that detail the possible procurement of additional system strength and voltage control services. This could include the conversion of existing facilities to synchronous condenser operation, as referred to in the Engineering Framework FY23 priority Action A23: Achieve optimal deployment of synchronous condenser capability in new and existing synchronous generators[105]. Additionally, see a study commissioned by the Australian Renewable Energy Agency (ARENA) that examines the technical requirements for repurposing existing generators as synchronous condensers was published on 22 June 2023[106].

[101] See https://aemo.com.au/-/media/files/media_centre/2017/aemo_summer-operations-2017-18-report_final.pdf.

[102] See https://hornsdalepowerreserve.com.au/.

[103] See https://aemo.com.au/-/media/files/media_centre/2017/aemo_summer-operations-2017-18-report_final.pdf.

[104] See https://www.aggreko.com/en-au/news/2017/auspac-news/victorian-temporary-standby-emergency-power-supply.

[105] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2022/nem-engineering-framework-priority-actions.pdf?la=en&hash=F5297316185EDBD4390CDE4AE64F48BB.

[106] See https://arena.gov.au/assets/2023/06/repurposing-existing-generators-as-synchronous-condensers-report.pdf.

Recommendation 4

AEMO recommends that each participating jurisdiction develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risks. These plans should be for an appropriate level of capacity for the region, and encompass details of the generation technology, connection point and connection arrangement, fuel supply adequacy, environmental considerations, construction and commissioning timelines as well as equipment availability and lead times.

6.6 Operational tools

Australia is experiencing the world's fastest and most profound power system transformation. The system is being directly impacted by decarbonisation, digitisation, democratisation and decentralisation. This is being accelerated by a complex range of societal, technological, economic and commercial shifts.

Without an uplift to AEMO's technical capability in the NEM, WEM and gas control rooms, operations support and markets teams, there is a risk that AEMO may not be able to reliably and securely manage these future power system needs.

The Operations Technology Program has been initiated to mitigate this evolving risk in line with the rules and regulations. It will leverage technological innovations, uplift systems, invest in advanced analytics and forecasting capabilities and support near real-time decision-making[107]. The program will enable AEMO to better manage increasing complexity, larger data sets and more frequent significant events to meet the ongoing needs of the Australian energy system.

As part of this program, AEMO has developed the Operations Technology Roadmap (OTR) to facilitate the uplift in operational capability and allow AEMO to manage the complex system of the future. The OTR is an ambitious vision for the future of operations technology in AEMO. Due to the uncertainty in future trajectory, it may evolve to meet the future system requirements and decisions made about the operating model in the Australian electricity sector. The key factors considered in the OTR include:

- The radical transformation of the Australian power system and its requirement for AEMO operations to be equipped with the appropriate tools to manage an increasingly complex system.
- The identification of key operational gaps by internal AEMO stakeholders and external stakeholder input.
- The need for a regular and ongoing review of the OTR, such that it is continually updated with the best information available.
- A business capability model for AEMO to baseline the capabilities in operations.
- An illustrative architecture, to illustrate how key subsystems are likely to become increasingly interlinked in the power system from 2030 onward.
- An operational data and model roadmap to illustrate key needs for the future of data management in AEMO.

[107] See https://aemo.com.au/en/initiatives/major-programs/operations-technology-roadmap.

- The need to enable operators in all NSPs to have the best quality data to enable optimal decision making. This will require sharing and standardisation of model and operational data between AEMO and the NSPs.
- The development of detailed roadmaps for 10 operational technology (OT) tools, extending to 2030 and including a future vision, drivers for change, risk assessment, high-level cost benefit, data requirements and OT tool requirements.
- Roadmaps for aspects related to operator human factors, buildings, facility design, hardware and equipment.
- Important aspects of OT tool development such as cyber security, software development processes and the use of artificial intelligence.

However, this requirement for an uplift in technical capability will not be unique to AEMO. As the power system grows in complexity, the effects will be experienced by all market participants. These changes bring the need for a significant uplift in capability for many organisations. If not planned for appropriately, this increased network complexity will also lead to a corresponding increase in risk of occurrence of system security incidents.

A recent review of Transgrid's operational capability shows this potential increase in risk, finding that the growth in complexity of the New South Wales power system by 2030 could result in a 570% increase in the risk of unserved energy arising from system security incidents, compared to a 2022 base. Some of the key risks identified by Transgrid include[108]:

- Reduced inertia and system strength due to retirement of coal leading to increased LOR conditions.
- Major transmission projects leading to prolonged outages and reduced redundancy.
- Complex and dynamic operating conditions due to the large increase in VRE.
- DPV leading to falling minimum demand, load shedding implications and large changes in load and generation based on weather.
- New REZs bringing new planning responsibilities and complex grid interface points.

These issues identified by Transgrid will be common across the NEM and it is important that these risks are understood and mitigated appropriately. As part of its review, Transgrid has predicted it can mitigate up to 60% of this risk, delivering net benefits of $863.3 million over 10 years.

AEMO recommends that all NSPs, where not already doing so, evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training.

Recommendation 5

In the context of the transforming power system and changing risk profile of the NEM, AEMO recommends that all NSPs, where not already doing so, evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training.

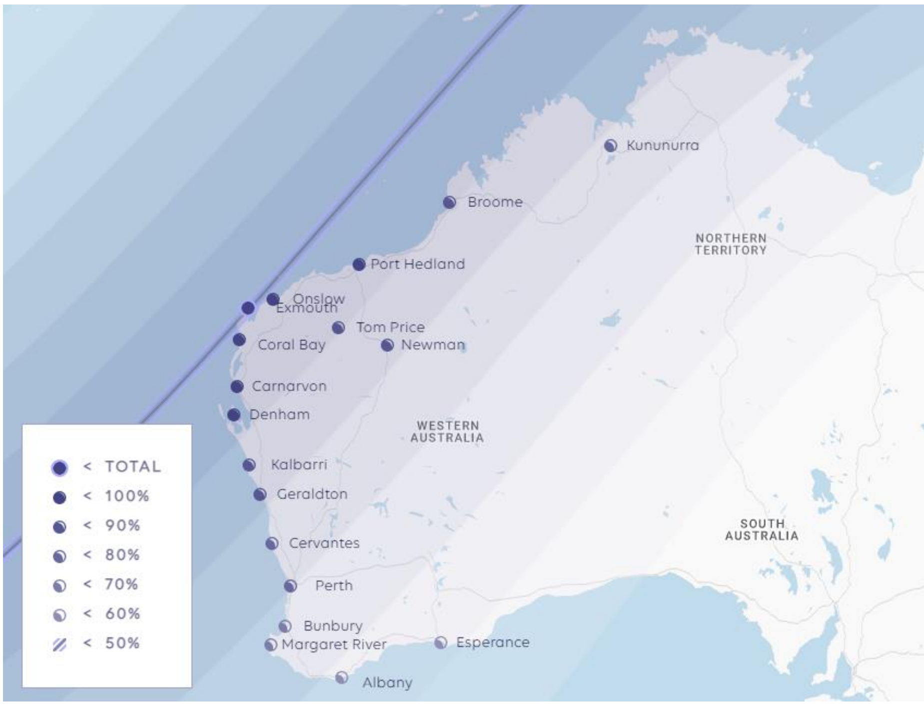
[108] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/general-power-system-risk-review-approach-consultation/transgrid.pdf?la=en

6.7 22 July 2028 solar eclipse

During a solar eclipse, the moon's transit across the sun diminishes solar irradiance at various levels and times over several hours. From a power system perspective, this results in a significant reduction in DPV and semi-scheduled solar generation output as the moon obscures the sun, followed by a significant increase as the eclipse concludes.

A solar eclipse that cast a shadow across parts of Australia and resulted in a short period of complete darkness in central and northern Western Australia occurred on 20 April 2023. AEMO issued market notices 107531 and 107532 declaring abnormal conditions according to the indistinct event framework, however no intervention was required to manage the risks associated with this particular event. As shown in Figure 15, the path of totality of the solar eclipse touched Exmouth, outside of the South West Interconnected System (SWIS), which experienced total darkness for around one minute. During this time, the greater Perth area was subject to a 60% to 80% reduction in sunlight.

Figure 15 Path of 20 April 2023 solar eclipse



Note: see https://ningalooeclipse.com/.

As these details were known in advance, AEMO took the following action to manage the impact on the SWIS:

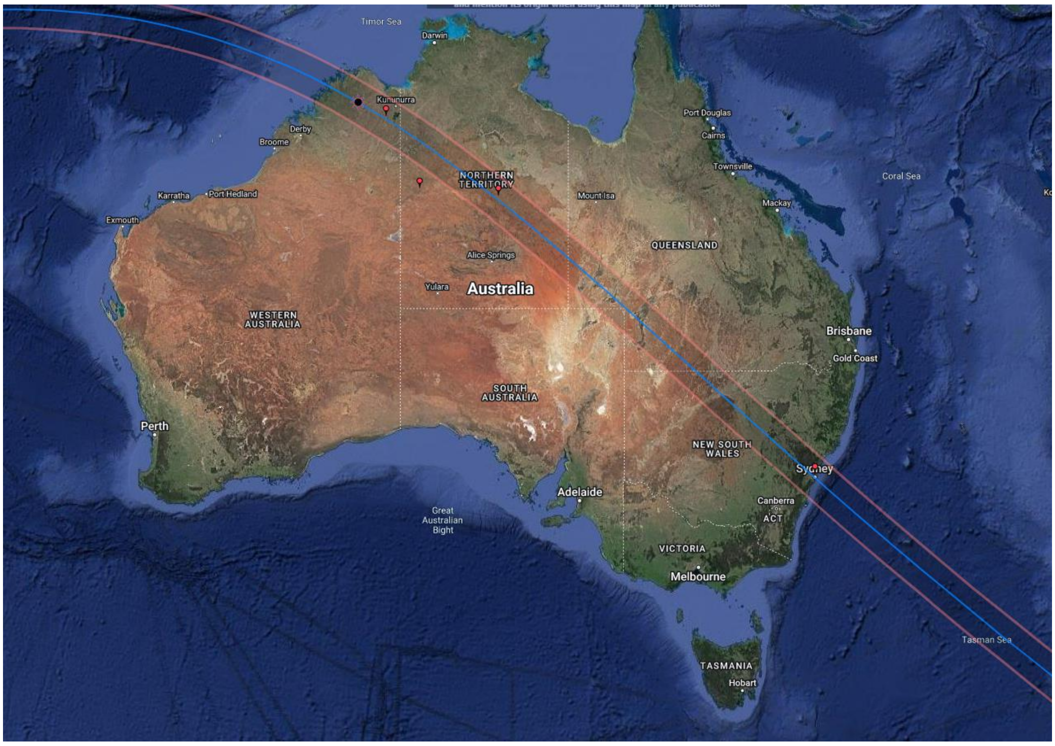
- Load forecasts were adjusted using weather eclipse data from the Bureau of Meteorology to reflect the impact of the eclipse on the load profile.
- Large solar farms were constrained to reduce ramping impacts.
- Additional load-following ancillary services (LFAS) were procured for the period.

As a result of the reduction in solar irradiance caused by the solar eclipse from 1000 hrs, the Western Australia total operational demand increased by approximately 700 MW over the first 90 minutes and reduced by 850 MW over the second 90 minutes. This impact on solar generation and electricity demand is similar to what has been observed as a result of volatile and dense cloud movement.

Australia's next total solar eclipse will occur on 22 July 2028. As shown in Figure 16, the path of the eclipse crosses from the Kimberley in Western Australia, through the Northern Territory, southwest Queensland, New South Wales, and passes directly over Sydney. This total eclipse's maximum duration of about 305 seconds (s) will occur in the remote Kimberly region of Western Australia, decreasing to about 224 s through Sydney. Locations in Western Australia and Northern Territory that see this total eclipse will experience approximately 90 minutes of partial eclipse before and after, while Sydney will experience about 70 minutes of partial eclipse before and after.

This eclipse will affect a greater proportion of the population centres, and correspondingly a greater proportion of DPV and semi-scheduled solar generation, than the partial eclipse that occurred on 20 April 2023. Hence, it is expected that this eclipse will have a far more significant impact on the NEM than the April 2023 eclipse had on the SWIS.

Figure 16 Path of 22 July 2028 solar eclipse



Note: See https://eclipse.gsfc.nasa.gov/SEgoogle/SEgoogle2001/SE2028Jul22Tgoogle.html.

The procedure for managing a solar eclipse is in accordance with SO_OP_3715[109], whereby AEMO's operations support teams first assess the presence of an abnormal condition that makes the occurrence of significant generator curtailment reasonably possible. If so, AEMO will issue a market notice, and under some situations, this may warrant some or all of the actions listed under Section 8.4.3 of SO_OP_3715:

- Constraining the dispatch of scheduled plant.

[109] 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.

- Limiting interconnector flows.
- Issuing directions or NER clause 4.8.9[110] instructions for the purpose of managing system strength, voltage, frequency or inertia requirements.
- Procuring additional market ancillary services.
- Reconfiguring the network (including sacrificial switching).
- Recalling planned network outages.
- Recalling planned generation outages.
- Maximising reactive power reserves.
- Activating contingency plans.
- Implementing temporary limits in supervisory control and data acquisition (SCADA) systems.
- DPV curtailment.
- Pre-contingent and/or post-contingent load shedding.

As described above, in general these actions will be targeted towards maintaining a manageable MW per minute rate of change in regional operational demand while complying with the other aspects of the technical envelope.

It should be noted that the reclassification framework of SO_OP_3715 is regularly reviewed for validity and modified where necessary following network events.

6.8 Potential for persistent oscillations from inverter-based resources to cause tripping of distributed energy resources (DER)

On 23 June 2022, voltage and reactive power oscillations were originated from the Port Augusta Renewable Energy Park (PAREP) in South Australia during commissioning tests. There was no notable response from the DPV systems, as this incident occurred during night-time. However, one battery manufacturer identified that 95% of its residential battery fleet disconnected at some point during the incident. In addition, power system effects such as flickering lights were reported during the incident. The root cause of the incident, rectification steps, and recommendations are documented in a reviewable operating incident report[111].

As part of the 2023 GPSRR, AEMO completed the following studies in PSS®E to assess the risks of a similar event occurring during a daytime period where power system oscillations causing a large amount of DPV to disconnect. As such, a simultaneous trip of DPV due to oscillations in South Australia were studied.

6.8.1 Case selection

To assess the potential impact of simultaneous trip of DPV due to oscillations in South Australia, a timestamp was considered from the FY 2021-22 period where the amount of DPV in South Australia and the power flow into South Australia through the HIC are simultaneously high. Generally, when South Australia experiences high levels of DPV, the power flow through HIC is from South Australia to Victoria. However, in this contingency, the DPV

[110] At https://energy-rules.aemc.gov.au/ner/468/253459#4.8.9.

[111] At https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/south-australia-power-system-oscillations.pdf?la=en.

amount in South Australia affects the contingency size and consequently increases the risk of South Australia synchronously separating from the rest of the NEM[112] when power flow through HIC into South Australia is sufficiently high.

In the selected timestamp for this study (25 January 2022 at 1131 hrs), the amount of DPV generation in South Australia is 1,188 MW, which is approximately 70% of the maximum DPV generation amount in South Australia reported for FY 2021-22. The power flow into South Australia via HIC is 346 MW.

The PSS®E case was generated from the OPDMS for NEM system corresponding to the system operation conditions for the selected timestamp. Generation and load dispatch in OPDMS study cases were unaltered and the values of the key parameters are given in Table 29.

Table 29 Key South Australia parameter values of the selected timestamp

SA DPV (MW)	Import into SA (MW)	SA demand (MW)	SA UFLS (MW)	SA synchronous generation (MW)	SA wind generation (MW)	SA solar generation (MW)
1,189	348	2,536	2,172	671	37	211

6.8.2 Study assumptions

In this study, only the DPV system was assumed to trip due to oscillations. This is the most onerous condition to consider, as the corresponding consumer load remains connected to the grid. For this study a peak-to-peak voltage oscillation magnitude of 8% is considered, similar to the oscillation that was reported during the PAREP incident. A peak-to-peak oscillation magnitude of 8% in voltage magnitude was assumed to cause disconnection of a fixed DPV level of 400 MW (35% of the DPV in South Australia in this case), which aligns with the DPV shake-off reported in historical incidents. A 50 ms delay between each DPV trip was assumed, to account for the tripping delay of DPV.

6.8.3 Study results

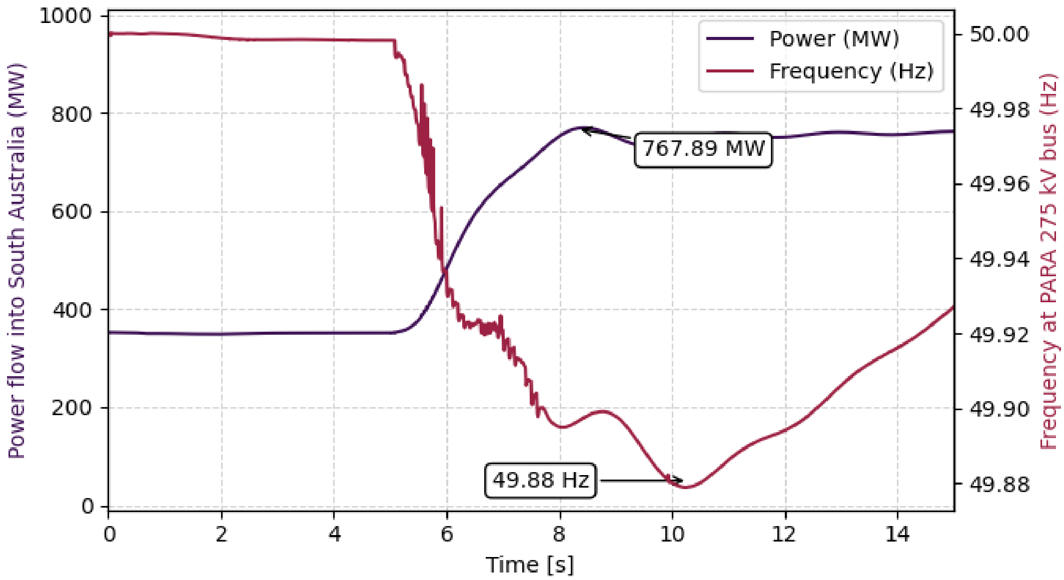
Key study results are given in Table 30 and the change in frequency and power flow into South Australia following the contingency is shown in Figure 17.

Table 30 Case results for mass DPV trip contingency

SA DPV trip amount (MW)	NEM frequency nadir (Hz)	RoCoF in SA (Hz/s)	HIC stable? (Yes/No)
400	49.88	0.05	Yes

[112] The risk of South Australia synchronously separating from the rest of the NEM reduces once PEC commences operation.

Figure 17 The change in frequency and power flow into South Australia following the contingency



Key findings

The studies of mass DPV trip contingency identified the following key findings:

- The frequency nadir is 49.88 Hz and the initial RoCoF measured at Para 275 kV bus is 0.05 Hz/s. Therefore, the power system FOS was met in this study.
- The power flow into South Australia through HIC increases up to 768 MW as the rest of the network responds to the loss of generation (DPV trip) in South Australia.
- No special protection schemes or under frequency load shedding were operated for this contingency. However, note that unmodelled power system effects due to oscillations (for example, flickering and resonances due to interactions) have the potential to be disruptive and impact the security and reliability of the power system.

6.8.4 Conclusions

- Based on the case studied, the impact of tripping 400 MW of DPV (35% of DPV in South Australia) on system stability is marginal. In this study, following the trip of DPV, HIC was stable. Although the impact on system stability is marginal, when an actual LOR condition exists, a trip of 400 MW DPV could severely impact the reliability of the electricity supply. In addition, during the PAREP incident, flickering of lights was reported. As such, persistent oscillations could affect the quality of the electricity supply.
- In this study, an 8% of oscillation magnitude is assumed to cause the disconnection of 400 MW of DPV. Note that a higher oscillation magnitude naturally has the potential to be disruptive and cause even more DPV disconnections. As such, the findings of this study are consistent with the recommendations relating to the power system oscillations in South Australia incident on 23 June 2022[113] and West Murray Zone power system

[113] At https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/south-australia-power-system-oscillations.pdf?la=en.

oscillations event on 16 November 2021[114]. AEMO recommends that an acceptable oscillations limit is developed in conjunction with suitable operational tools and installation of adequate high-speed monitors to support control room operators in managing future oscillation events on the power system. This will enable operators to monitor and effectively manage oscillations within operational timeframes.

- A multitude of risks, including but not limited to persistent oscillations, could cause mass tripping of DPV. These risks could arise during plant commissioning, the course of operation (for example, plant issues, outages and changes in network configuration impacting the network characteristics) or due to external factors such as cyber risks. AEMO is currently working through multiple initiatives to address the risks identified. These include:
  - As part of the access standards review, for new connections, AEMO is currently engaging with industry on the suitability of the requirements of NER S5.2.5.10 (protection to trip plant for unstable operation), with a focus on asynchronous generators. As part of this engagement, AEMO will consider amendments to the access standards for generators to:
    - Monitor for instability and alert generator operators, the NSP and AEMO.
    - Determine their contribution to system instability.
    - Trip or ramp down under critical system conditions where the system is unstable and/or where a generator identifies itself as a high contributor to the identified system instability.
  - AEMO is currently reviewing generator commissioning requirements and will consider the recommendations and findings relating to power system oscillations in South Australia incident on 23 June 2022 to ensure the risks that could arise during commissioning are mitigated.
  - In the power system oscillations in South Australia incident on 23 June 2022, an external device, which is part of the manufacturer's typical battery system configuration, was identified as the root cause for the disconnection of one manufacturer's 95% of the residential battery fleet. AEMO is currently pursuing activities to clarify requirements within the Australian Standards (AS/NZS4777.2:2020) related to devices external to household inverters which can impact overall system performance.
- It is important to note that the case studied used historical operating conditions, and the installed capacity of DPV in South Australia is forecast to increase significantly by 2027-28, to approximately 3,500 MW (compared to the current installed capacity of 2,100 MW)[115]. Therefore, the impact of this type of event on network stability could be more severe in the future.

6.9 Other emerging risks

6.9.1 Weather-related risks

Weather events have the potential to cause major supply disruptions to the NEM either by:

- Causing a non-credible contingency,
- Limiting the output of a group of generators or technology type, or

[114] At https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/west-murray-zone-power-system-oscillations.pdf?la=en.

[115] According to ISP *Step Change* scenario data.

- Constraining the network between generation and load centres.

AEMO has updated the reclassification criteria in the Power System Security Guidelines[116] (SO_OP_3715) following the indistinct events rule change (see Section 1.6). The update to SO_OP_3715 provides an expanded reclassification framework to assess the risks posed by various types of weather events including:

- Bushfires.
- Lightning threats to double-circuit transmission lines.
- Severe wind (including tropical cyclones).
- Geomagnetic disturbances.
- Floods.
- Widespread pollutants.
- Landslides.
- Earthquakes and tsunamis.

In each case, the updated criteria outline AEMO's considerations in deciding to reclassify a non-credible event as credible based on the threat posed. The revised reclassification framework allows AEMO to put controls in place to manage a wider range of conditions, increasing AEMO's overall ability to maintain power system security.

6.9.2 Fuel supply interruptions/supply scarcity issues

Interruption to fuel supply chains has the potential to cause major supply scarcity issues. Below are some examples of events that could lead to supply scarcity issues:

- Thermal power stations:
  - Loss of one coal conveyor out of two conveyor systems suppling coal to a power station.
  - Rain causing wet coal, leading to reduced and unreliable generation at one or more power stations, or major disruptions to coal deliveries via trains.
  - Problems with ash handling plant, requiring a reduction in generation at a power station or the shutdown of multiple generating units.
  - Scarcity of boiler feed water (demineralised water) during flooding, requiring a reduction in generation or inability to continue generation.
  - Scarcity of cooling water during droughts.
  - Gas supply limitations due to failures at gas plant such as the explosion of Longford on 25 September 1988 and/or gas pipeline/compressor failures.
- Hydro power stations:
  - Low reservoir water levels during droughts.

[116] 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.

  - Inability to generate at capacity due to limitations of downstream water releases in avoiding downstream flooding during extreme rainfall periods.
  - Inability to generate at full capacity due to downstream reservoir air space limitations (licence restrictions limit water releases during certain months of the year).
- Other causes:
  - Unplanned network outages requiring reduction of large amounts of IBR causing supply reliability issues.
  - NEM-wide low wind/solar generation for consecutive days (as occurred in June 2022).
  - Unplanned outages of the elements of interconnectors that cannot be restored during planned outages of elements of the same interconnector.
  - Loss of common station services such as compressed air, loss of station services transformers.

6.9.3 Failure of SCADA systems

SCADA systems are critical for power system operation and their failure can have a significant impact on power system operability, resilience and market operation. Since January 2021, there have been five major SCADA failure incidents.

From experience of recent SCADA failure events, AEMO has identified the following associated power system impacts/risks:

- SCADA failures result in suspension of the spot market in the affected region(s) if AEMO identifies that it is no longer possible to operate the spot market in accordance with NER 3.8 and 3.9. In four of the major SCADA failures since January 2021, AEMO suspended the regional spot market until SCADA (with suitable redundancy) was restored. Market suspension impacts the functioning of the market as it is a deviation from normal operation of the market.
- SCADA failures impacting both NSPs and AEMO increase the risk that key power system parameters such as frequency, voltage and line thermal limits move outside of acceptable levels. Depending on the level of any residual oversight, operators may be unable to effectively control the power system, with potential for frequency to breach the FOS, voltage levels to exceed NER or equipment limits. These phenomena in turn have the potential to result in adverse power system performance including plant tripping, overloading or voltage collapse. Where SCADA outages are significant and of long duration, this risk window is increased. During three of the recent SCADA failures, both AEMO and the TNSP lost SCADA visibility. This complete loss of SCADA left limited means (such as limited NSP backup systems and dispatching staff to key substation to physically monitor parameters) for control room staff to monitor and control key power system parameters.
- A SCADA failure reduces power system resilience, as it impairs the ability of power system operators and participants to respond effectively to contingency events and challenging power system conditions. Should a contingency (credible or non-credible) or significant market event occur during a SCADA outage, actions that can normally be taken to maintain power system security such as implementing new constraints, re-dispatching generation, switching of equipment or procuring additional ancillary services could be partially or wholly unavailable.

Due to their system/market impact, AEMO has published a reviewable incident or market event report for each of the SCADA failures mentioned above. The key recommendations to improve SCADA reliability and resilience from these published reports are summarised below:

- Since January 2021, there have been five SCADA failures resulting in impacts on the market and additional complexities to the operation of the power system. AEMO is concerned about the integrity of NSP's critical information technology (IT) systems. As such, AEMO:
  - Plans to discuss these incidents through the Power System Security Working Group (PSSWG).
  - Recommends all NSPs review their critical IT systems. This review should consider any improvements to ensure high reliability of systems and effective, timely responses to system issues.
- AEMO recommends NSPs undertake routine failover testing to help identify possible issues following failover from primary to secondary and secondary to primary SCADA links.
- AEMO recommends that data communication providers review their SCADA systems and consider implementing suitable alarms and heartbeat displays to alert operators of ICCP link failures.
- When NSPs are carrying out work that could potentially impact the operation of the power system, AEMO recommends:
  - NSPs arrange the work at times where key personnel are available to respond quickly and rectify any issues, and
  - NSPs advise their control rooms and AEMO's control room in advance of this work and seek permission to proceed from the NSP and AEMO control rooms before commencing the work.

6.9.4 Cyber-attack related risks

AEMO assesses and plans for potential events that could affect the power grid's reliable operation, including cyber risks, which pose a significant threat to the power sector. As the power system moves towards incorporating internet connected devices including renewable generation and moves to a more decentralised grid, this brings significant technological complexity as well as additional security considerations and increased dependence on telecommunications to provide real-time telemetry and manage the grid securely and safely. While a smarter, more connected electrical grid can be more efficient and resilient against natural threats, it is potentially more vulnerable against cyber-attacks.

A reliable energy supply underpins Australia's prosperity, making the energy sector a potential target for a range of cyber security adversaries. Over the last decade, the Australian energy sector has experienced a marked increase in attacks due to the increasing interconnection of systems and the broader push to digitalise all facets of the economy. These attacks have the potential to come in a variety of different forms, such as:

- Large-scale, destructive acts of sabotage, such as those which have occurred overseas, with one example in Ukraine resulting in the disconnection of 30 substations for three hours, leaving up to 230,000 customers without power.
- IT-specific ransomware deployed within an OT or an industrial control system (ICS) environment. In late 2019, ransomware disrupted the operations of a gas plant, forcing it to shut its pipeline operations for two days.
- Attacks focused on reconnaissance and collecting user credentials, which could be used for future attacks around disruption to the power supply.
- Utilising vulnerabilities in third party networks. As AEMO now extends beyond directly managed and controlled infrastructure to third-party networks, the security of the supply chain becomes even more important.

- Targeting of DER, such as rooftop solar. The significant generation contribution from DER combined with the absence of security controls in these devices pose a substantial risk to the system.

The reclassification criteria in the Power System Security Guidelines[117] (SO_OP_3715) now expressly include criteria for reclassification due to an actual or credible threat of cyber-attack. AEMO will decide whether non-credible contingency events involving multiple plant should be reclassified as credible due to cyber risk having regard to:

- Advice/alerts by Australian Cyber Security Centre.
- Cyber security advice received by AEMO Registered Participants and relevant customers.
- Potential scale of impact (for example, organisation-wide, industry-wide, primary or backup systems).
- Criticality of systems at risk.

The reclassification criteria provide for a range of possible measures to manage cyber-attack risk after reclassification, in Section 8.4.3 of the Power System Security Guidelines.

6.9.5 Control/protection system interaction risks

Control system interactions

Increasing amounts of IBR generation, such as wind and solar power plants, and power electronics-based loads, are being integrated into the Australian power system, which has resulted in complex power system dynamics and new types of stability issues emerging. As IBR comprise control systems with different bandwidths, the stability issues stemming from these devices appear over a wide range of frequencies (from a couple of hertz to tens of kilohertz). The interactions among relatively slower control loops in IBR, such as active and reactive power control, cause near-synchronous resonance. Conversely, the interactions of faster control loops in IBR, such as current control and grid synchronisation using a phase-locked loop (PLL), cause super-synchronous resonance. This phenomenon has not been observed in traditional, synchronous machine-dominated networks where stability issues typically appear as low frequency local and wide-area oscillations.

The risk of control interactions in IBR is increasing due to two primary factors:

- In recent years, there has been a steep increase in the number of IBR integrated into the NEM. As the number of IBR connected to the network increases, the probability of them interacting with each other increases. Interactions could be between IBR that operate in proximity to each other, or among other elements in the power system such as series compensated transmission lines.
- IBR plants are generally connected to weaker parts of the network, thereby exacerbating any stability issues.

Protection system interactions

Remedial action schemes (RASs) are protection schemes in the NEM that operate automatically to prevent adverse outcomes following certain credible and non-credible contingency events. There are several RASs currently enabled in the NEM that provide a wide range of benefits to the power system including, but not limited to, minimising the impact of system incidents, and improving asset utilisation. While RASs are critical to manage

[117] 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.

risks in the power system, they must be properly designed and periodically reviewed to ensure that they operate effectively and as intended. RASs have the potential to exacerbate the severity of an event or lead to cascading failures and supply disruptions if they fail to operate as expected. As such, AEMO published the RAS Guidelines[118] in collaboration with NSPs, which define the requirements for developing RASs in the NEM. The guidelines define good practice for design, modelling, and review of RASs to ensure that they meet their performance requirements and maintain their effectiveness under a wide range of operational conditions, as well as adapting to power system changes over time.

The guidelines outline RAS design considerations, accounting for the potential failure modes, unintended operation, and inadvertent interactions. RASs have the potential to either fail to operate, or operate in unintended or unexpected ways due to equipment failure, an error, or a limitation in the scheme design. If a RAS does not respond as and when expected, this introduces additional risk to the power system. This means considering possible failure modes in the RAS design stage is essential to inform its proper design and testing.

In addition, inadvertent interactions between different RASs and/or other protection schemes can cause undesirable outcomes and add unnecessary complexity to the operation of the power system. Proper coordination with existing protection systems, backup schemes (if applicable), and other RASs is imperative to prevent these inadvertent interactions.

As such, it is increasingly critical for NSPs to engage in extensive and detailed joint planning in the design and testing of RASs to ensure that all existing and future RASs operate effectively and do not cause adverse interactions or exacerbate non-credible contingency events.

6.9.6 Future contingencies with great uncertainties in detailed design/parameters

Where a control scheme is likely to be the most economic way to address a risk, it is prudent to take into consideration the time to design and implement the control scheme. Ideally, the risk study is completed under the most likely future operating scenario, to illustrate the need and efficacy of the scheme. For the 2023 GPSRR, this future modelling included committed, anticipated and actionable projects in the FY 2027-28 according to the 2022 ISP *Step Change* scenario.

The inclusion of future actionable and anticipated projects introduces considerable design uncertainty, meaning that detailed studies become less accurate. Therefore, in planning these projects, as required by NER S5.1.8[119], AEMO recommends that NSPs consider non-credible contingency events which could potentially jeopardise the stability of the wider power system. This includes, but is not limited to, anticipated and actionable projects listed in Table 4 of Section 2.2 of this GPSRR, and 2022 ISP actionable projects Marinus Link and VNI West[120].

[118] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/publication-of-remedial-action-scheme-guidelines/further-information/remedial-action-scheme-guidelines-consultation.pdf?la=en.

[119] At https://energy-rules.aemc.gov.au/ner/452/229047#S5.1.8.

[120] 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.

[121] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/publication-of-remedial-action-scheme-guidelines/further-information/remedial-action-scheme-guidelines-consultation.pdf

Recommendation 6

AEMO recommends that, in line with the requirements of NER S5.1.8, NSPs continue to consider non-credible contingency events which could adversely impact the stability of the power system. In considering these non-credible contingency events, NSPs should identify and implement suitable controls to mitigate any identified risks. It is anticipated that these controls may involve the implementation of new remedial action schemes, in which case NSPs should consult with AEMO and refer to the Remedial Action Scheme (RAS) Guidelines developed by AEMO and NSPs[121].

6.9.7 Management of maximum contingency sizes

The management of contingency sizes must be considered as new generation and transmission infrastructure is constructed to assist in Australia's energy transition. The creation of new REZs will bring additional generation and transmission infrastructure that will require careful consideration of contingency sizes.

In the mainland NEM, the current largest credible contingency is the loss of Kogan Creek, which can result in the loss of up to 763 MW. There is also the Generator Fast Trip (GFT) scheme in North West Victoria with a total generation capacity that could reach approximately 800 MW if not limited by constraints. In Tasmania, there is a prescribed limit of 144 MW for a credible contingency. This limit is imposed in Tasmania due to there being less available FCAS, resulting in its power system being more susceptible to frequency events. In contrast, the mainland system has a greater scale, generation mix and availability of FCAS, and as such does not have a maximum contingency limit.

As detailed in Section 1.6, a recent review of the FOS[122] investigated contingency sizes and recommended against introducing a maximum generation contingency limit for the mainland NEM. The review determined that enforcing a limit could discourage investors from developing large new connections that may be the most economical solution. This finding indicates that, while 763 MW is the current maximum credible contingency, there is the potential that this could increase in the future. This potential increase in maximum contingency size must be considered as part of future planning.

Further consideration of the maximum contingency size is also required as part of the development of new REZs and the corresponding transmission augmentations. The significant changes to the network, and the change in generation dispatch to include more VRE, will further complicate the management of maximum contingency size. There will be multiple factors that will need to be considered, including:

- The size of new individual generating units and whether they exceed the existing maximum contingency. A new maximum contingency may require additional studies or augmentations.
- The change in transmission line power flows due to new generator connections and transmission augmentations, resulting in larger contingencies of main transmission corridors.
- The network outages, testing and commissioning of new generation and network resulting in a loss of redundancy or higher loading in existing lines.
- The difficulties in scheduling outages due to increase of constraints when co-optimising with VRE output.

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

- The use of multiple circuits when connecting new generation, providing redundancy such that loss of any one circuit will not result in an unacceptable contingency size.
- The route diversity of circuits, preventing the loss of any individual asset such as a transmission tower resulting in an unacceptable contingency size.
- The redundancy in substation design components, such as transformers, circuit breakers and bus configurations.

Management of maximum contingency sizes will require a co-ordinated approach, considering individual generator connections as well as the overall impact that multiple generators and new REZs will have on the transmission network.

6.9.8 Management of risks associated with changing generation patterns

As existing coal units retire and generation is sourced from other locations, this can affect the typical dispatch patterns of the power system. After the retirement of Liddell Power Station and the potential closure of Eraring Power Station, it is forecast that there will be increased utilisation of the 330 kV lines which supply Sydney, Newcastle and Wollongong. This change in dispatch patterns also results in changes to the risk profile for non-credible contingencies on existing network corridors. Due to this, the consequence of a risk may be more severe, and/or the likelihood of a risk occurring may increase.

In assessing network risks, Transgrid advised AEMO of possible increased future risk conditions for non-credible contingencies on the 330 kV lines supplying Sydney, Newcastle and Wollongong following a potential Eraring closure. Potential risk consequences may include voltage collapse or cascading thermal overloads. Transgrid plans to study these risks to confirm whether/when they are expected to be present, and if applicable assess whether it is economical to mitigate the risks.

Recommendation 7

Transgrid is investigating the risk and consequence of non-credible contingencies on the 330 kV lines supplying Sydney, Newcastle and Wollongong following potential Eraring Power Station closure. AEMO recommends that Transgrid share its investigation findings with AEMO for consideration in future GPSRRs.

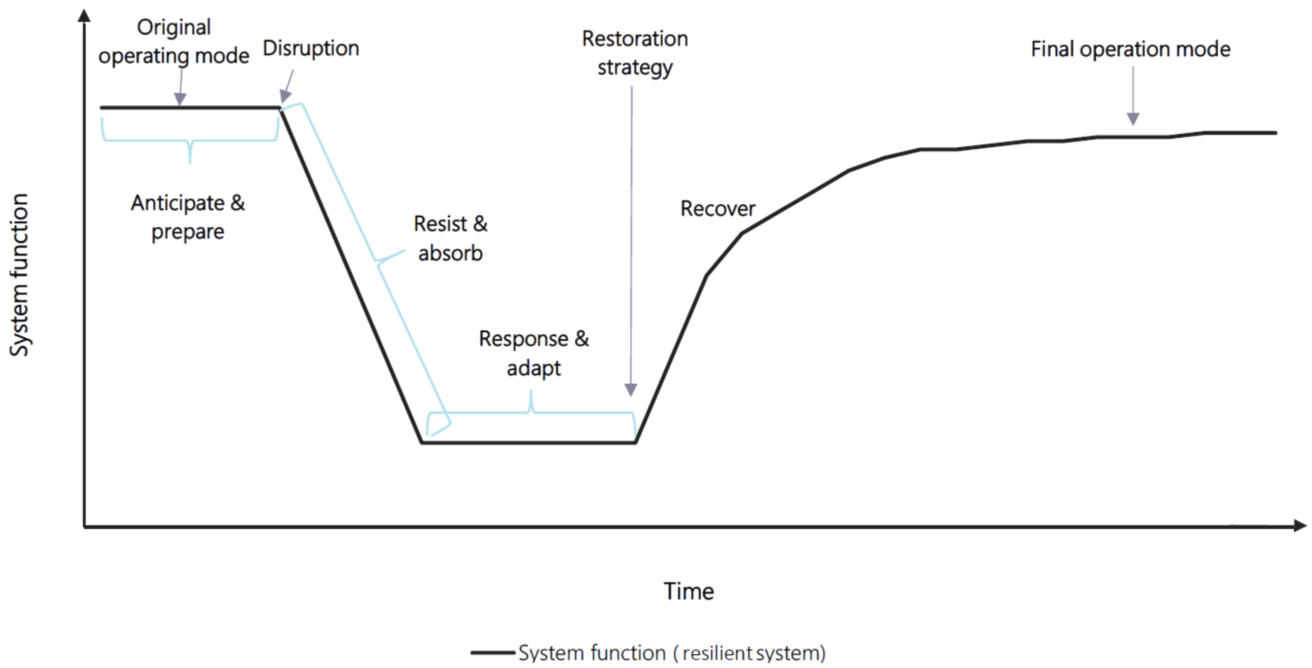
6.9.9 System resilience

Figure 18 sets out the different stages of response that are required to ensure the power system is resilient to disruptions. The figure illustrates that the measures to resist and absorb, respond to adapt as well as recover are all steps leading to a final operating mode following an initial disruption.

As discussed throughout this report, there are a range of factors that impact the resilience of the power system. Together, or in isolation, these factors have the potential to mean that particular disruptions may have a greater impact on the power system – reducing the resilience of the initial operating mode prior to a disturbance. It is therefore crucial to ensure that systems, services and processes used to recover following an event are adequate, including those used for system restart as well as restoration of supply. This is increasingly challenging in the context of the retirement of synchronous generators, which have historically provided restart services.

AEMO has a number of initiatives underway to evaluate methods and options of utilising IBR for restart services and/or to assist with the restoration process, which will be progressively more critical as the power system continues to transform.

Figure 18 Process followed by a resilient power system through disruptions



Source: L. Yanling, Z. Bie and A. Qiu, "A Review of Key Strategies in Realizing Power System Resilience," Global Energy Interconnection, Vol.1, No.1, January 2018.

7 Protected events

7.1 Existing protected event

Under NER 5.20A.1(c), a GPSRR is required to assess the following matters for existing protected events:

- Adequacy and costs of the arrangements for management of an event.
- Whether to recommend a request to revoke the declaration of an event as a protected event.
- Where a revocation request is not recommended, the need to change the arrangements for management of an event.

There is presently only one protected event declared by the Reliability Panel:

> "*The loss of multiple transmission elements causing generation disconnection in the South Australia region during periods where destructive wind conditions are forecast by the Bureau of Meteorology*"[123].

This protected event is managed as follows:

- AEMO imposes a 250 MW South Australia import limit on the Heywood Interconnector during forecast destructive wind conditions in South Australia.
- An EFCS called the wide area protection scheme (WAPS)[124] is in place in South Australia to lower the risk of islanding due to trip of up to 500 MW of South Australian generation while South Australia is importing power.

Table 31 summarises the utilisation of the existing protected event since its declaration on 20 June 2019, including the periods during which the South Australia 250 MW import constraint[125] was binding and the estimated associated costs[126] to the market.

Table 31 Utilisation of the existing South Australia destructive winds protected event and the costs of the South Australia 250 MW import constraint binding

Market notice	Invoked at	Revoked at	Binding period (mins)	Cost of constraint ($)
69177	08/08/2019 1200	08/08/2019 2355	None (SA exporting power)	None
72843	22/01/2020 1200	22/01/2020 2255	None (SA import < 250 MW)	None
93779	11/01/2022 1920	11/01/2022 2000	40	24,000
94056	26/01/2022 2035	26/01/2022 2300	120	94,000
96776	04/06/2022 1915	05/06/2022 0530	None (SA exporting power)	None
102723	30/10/2022 1655	30/10/2022 2100	None (SA exporting power)	None
108385	7/06/2023 1230	07/06/2023 2100	None (SA import < 250 MW)	None

[123] Reliability Panel AEMC, Final Report AEMO Request for a Protected Event Declaration, 20 June 2019, p22, https://www.aemc.gov.au/sites/default/files/2019-06/Final%20determination%20-%20AEMO%20request%20for%20declaration%20of%20protected%20event.pdf.

[124] The WAPS is an upgrade of the previous System Integrity Protection Scheme (SIPS).

[125] The VS_250 market constraint imposes an upper transfer limit of 250 MW from Victoria to South Australia on Heywood and is invoked as part of the existing South Australia destructive winds protected event.

[126] Costs were calculated assuming Victorian brown coal was displaced by South Australian OCGT when the constraint bound, as was the methodology used in the original AEMO request for the protected event, at https://www.aemc.gov.au/sites/default/files/2019-04/AEMO%20Request%20for%20protected%20event%20declaration.pdf.

The 2022 PSFRR recommended AEMO investigate whether the South Australian destructive wind protected event could be managed under updated contingency reclassification criteria[127], and if so to recommend revocation of the protected event.

AEMO's subsequent investigation, which included consultation with ElectraNet and the AEMC, concluded that the protected event could be effectively managed under the contingency reclassification framework and NER S5.1.8.

AEMO also notes that the contingency reclassification framework and protected event rule changes were both initiated in response to the 2016 South Australian black system event. AEMO considers the existing South Australian 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 has concluded that:

- Appropriate constraints for the network topology post PEC Stage 1[128] can be implemented under the updated contingency reclassification criteria.
- Changes to special protection schemes to accommodate PEC can be made efficiently under NER S5.1.8.

Therefore, on 11 April 2023 AEMO submitted a request to the Reliability Panel to revoke the protected event prior to 1 October 2023[129]. The Reliability Panel intends to assess this request under the expedited rules consultation process and will publish a draft determination to assist stakeholders interested in the proposal[130].

As a request to revoke the protected event is already under consideration, no further assessment of the protected event has taken place. However, if the existing protected event is not revoked, AEMO may consider requesting a revised protected event to reflect the network changes for PEC.

7.2 QNI protected event assessment

The 2022 PSFRR recommended AEMO investigate whether a QNI protected event or an appropriate SPS should be implemented to mitigate the risk of QNI separation for interconnector contingencies elsewhere in the NEM.

To investigate the feasibility of a QNI protected event or SPS, AEMO has studied the following non-credible contingencies in detail[131]:

- Loss of VNI (2022 PFSRR).
- Separation of South Australia through loss of Heywood – South East 275 kV lines (2022 PFSRR).
- Loss of Columboola – Western Downs 275 kV lines resulting in large loss of load (2022 PFSRR).

[127] Updated reclassification criteria were implemented on 9 March 2023, the effective date of the National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule: https://www.aemc.gov.au/rule-changes/enhancing-operational-resilience-relation-indistinct-events.

[128] ElectraNet to provide AEMO with updated limits advice to apply during destructive winds and post PEC Stage 1's connection.

[129] Which is prior to the expected date of synchronous electrical connection of South Australia to New South Wales via PEC Stage 1.

[130] See https://www.aemc.gov.au/news-centre/media-releases/advance-notice-intention-initiate-and-expedite-aemos-request-revoke-south-australian-protected-event?utm_medium=email&utm_campaign=AEMC-Update-18-May-2023&utm_content=aemc.gov.au%2Fnews-centre%2Fmedia-releases%2Fadvance-notice-intention-initiate-and-expedite-aemos-request-revoke-south-australian-protected-event&utm_source=cust49597.au.v6send.net

[131] Further details can be found in Section 5.2 of this report and the published 2022 PSFRR, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en.

- Loss of both 275 kV lines between Calvale and Halys with upgraded CQ and SQ SPS (2022 PSFRR).
- South Australia separation at MLTS (2022 PFSRR and 2023 GPSRR).
- Fault on Loy Yang B unit 2 transformer with No. 3 500 kV bus circuit breaker failure (2023 GPSRR).
- Large amount of generation and DPV loss in SQ (2023 GPSRR).

These studies confirm that there is an existing risk of QNI instability for a range of non-credible contingencies. AEMO's studies show that QNI separation is possible for a range of non-credible contingency events that cause QNI flow to exceed 1,700 MW export or 1,400 MW import.

Unlike the South Australian destructive winds protected event, which addresses an identifiable risk condition (destructive wind forecast) for which the protected event constraints need to be invoked, the risk of QNI separation is driven by a large range of possible non-credible contingency events across the NEM which are not necessarily linked to readily identifiable risk conditions. Therefore, network constraints identified in a protected event to manage QNI separation risk would likely need to apply for a much wider range of conditions and potentially at all times.

In considering a protected event to manage this risk, AEMO identified three initial options:

- Option 1 – do nothing.
- Option 2 – constrain QNI to reduce the risk that a non-credible contingency event causes QNI flow to transiently exceed the 1,700 MW export and 1,400 MW import levels.
- Option 3 – constrain other interconnectors and generator contingency sizes to reduce the risk that QNI flow transiently exceeds the 1,700 MW export and 1,400 MW import levels.
- Option 4 – procure regional FCAS during periods of high QNI flows when Queensland is more likely to island following a non-credible contingency event.

AEMO ruled out Option 1 as it does not address the existing and increasing risk of QNI instability following a range of non-credible contingencies.

AEMO ruled out an Option 3 protected event as, due to the number of non-credible contingency events that have the potential to cause QNI instability, it would require constraints on many generators and circuits throughout the NEM and therefore be prohibitively expensive and extremely challenging to implement.

AEMO also ruled out an Option 4 protected event, as the cost of procuring regional FCAS was anticipated to be at least as expensive as constraining wind and solar down and increasing the dispatch of coal generation at its SRMC to constrain QNI flow.

AEMO conducted a screening assessment to determine if a protected event constraining QNI (Option 2) would yield negative net market benefits using assumptions likely to produce high market benefit. If this screening assessment shows little or negative net market benefit, under favourable conditions, the use of constraints (applied via a protected event) is unlikely to be an economically viable means of mitigating the risk of QNI instability.

AEMO's assessment considered only the network post PEC stage 2, as AEMO considered that a QNI protected event is unlikely to be able to be implemented before the scheduled PEC stage 2 synchronisation, currently December 2024. This is due to the extensive analysis required for AEMO's declaration request and the time required for the Reliability Panel to review and conduct industry consultation on any request submitted.

AEMO conducted a cost/benefit analysis across two scenarios, assuming that constraining QNI could remove the risk of a non-credible contingency causing QNI instability, synchronous separation and subsequent load shedding. Assumptions that were likely to yield positive net market benefits were used, so that if low or negative net market benefits were observed in all scenarios, it would indicate that there are unlikely to be any system conditions in which constraining interconnectors is an economically viable strategy to mitigate the risk of QNI instability.

The assumptions used in the assessment included:

- QNI transferring at maximum capacity into New South Wales.
- If Heywood trips, this will cause QNI to become unstable and trip, triggering UFLS. UFLS assumed to shed load equal to 1.08 x QNI flow[132].
- Constraining QNI from 1,450 MW to 1,050 MW import to New South Wales (a 400 MW reduction) reduces the risk of QNI instability/separation following a trip of Heywood from 100% to 0%[133].
- An average load interruption time after UFLS operation of 52.8 minutes.
- A value of customer reliability of $50.42 per kWh.
- The protected event constraints on QNI flow are achieved by constraining wind and solar down, and increasing dispatch of coal generation at its short run marginal cost (SRMC) as outlined in Table 32.

Table 32 Coal short run marginal costs

Region	Lowest SRMC coal unit (per MWh)	Average SRMC coal unit
New South Wales	$22.06	$38.21
Victoria	$13.11	$13.58

A. AEMO used the SRMC generation costs published in the draft 2023 IASR assumptions book, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/draft-2023-inputs-and-assumptions-workbook.xlsx?la=en.

The results of AEMO's analysis are summarised in Table 33 below.

Table 33 QNI protected event screening study results

Scenario	Description	Net market benefit per hour of constraint lowest coal SRMC	Net market benefit per hour of constraint average coal SRMC	Net market benefit per hour of constraint highest coal SRMC
1	• QNI constrained by 400 MW • Queensland wind/solar constrained down by 400 MW • New South Wales black coal increased by 400 MW	-$4,037	-$10,500	-$16,104
2	• QNI constrained by 400 MW • Queensland wind/solar constrained down by 400 MW • Victoria brown coal increased by 400 MW (and exported to New South Wales)	-$459	-$647	-$913

[132] Actual levels of UFLS triggered in any given event would depend on multiple factors including levels of inertia, FCAS, demand and others at the time of the event. The 1.08 x QNI flow assumption comes from analysis in the 2022 PSFRR, which found 1.08 x QNI flow of UFLS was triggered in one simulation.

[133] The level of constraint necessary to remove the risk of QNI instability would vary depending on network conditions; 400 MW has been chosen as an initial assumption which will maintain QNI flow below 1,700 MW for a trip of Heywood Interconnector. Larger constraints may actually be required to sufficiently reduce the risk of QNI instability for other contingencies such as a trip of PEC.

As shown above, all scenarios produce negative net market benefits even when assessed using assumptions likely to produce positive net market benefits.

In practice, these QNI constraints would bind at times of high QNI flow into New South Wales. It can reasonably be assumed that during these times, low-cost generation in New South Wales is unlikely to be available and sufficient affordable Victorian generation cannot be imported into New South Wales due to VNI limits. Therefore, the cost of re-dispatching generation to limit QNI flow is likely to be significantly higher than the coal SRMCs assumed for this analysis, and the use of constraints (applied via a protected event) is unlikely to be an economically viable means of mitigating the risk of QNI instability.

As a result of this analysis, AEMO is not planning to request the Reliability Panel to consider declaring a protected event for contingencies that cause QNI instability.

7.3 Non-credible synchronous separation of South Australia from the rest of the NEM

AEMO previously identified that the deterioration of UFLS capability in South Australia increased the risk of cascading failure events following a non-credible separation of the region. Constraints were implemented under the South Australian regulations to limit imports into South Australia in periods where UFLS availability is low. The 2020 PSFRR[134] proposed that AEMO would explore recommending the declaration of a protected event to formalise those constraints under the NER framework and manage additional risks associated with a separation event.

AEMO's subsequent analysis has identified a suite of minor factors that contribute to the overall risk and has developed a number of low-cost measures to reduce risk to be implemented in the period prior to full commissioning of PEC Stage 2. All the recommended measures can be implemented without a protected event. Declaration of a protected event also has a number of flow-on implications, which require extensive further study and may not be economically feasible to manage at this time.

For these reasons, following extensive analysis and stakeholder engagement, 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.

AEMO's full analysis and recommendations can be found in the report on these studies[135].

7.4 Protected event framework review

Through experience of applying the existing protected event framework AEMO has the following observations and recommendations:

- The NER require that any protected event is treated identically to a credible contingency with regards to voltage control and voltage unbalance requirements, system stability assessment, and system strength assessment. Multiple NER clauses reference credible contingency events and protected events identically,

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

[135] 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

requiring that AEMO, NSPs and market participants take actions to manage protected events in an identical manner to credible contingency events. This can create undesirable outcomes:

– The studies necessary to assess each dimension of a particular non-credible contingency event and determine a full suite of measures to ensure that each relevant power system requirement remains within the limits for a credible contingency event can constitute a very large body of work. Furthermore, potential solutions may not be technically or economically feasible to deliver. As these appear to be pre-requisites to the declaration of a protected event, it is often extremely challenging to provide the extended cost-benefit analysis that would be necessary to support the Reliability Panel's consideration of a new protected event. The need to assess these additional aspects of managing a protected event makes an already long process for assessing possible new protected events even slower, and highly onerous.

– The lack of flexibility in the framework may mean that prudent pre-incident/event action to address known frequency risks cannot be taken at all, if the costs of additionally managing system strength and voltage stability to the same standard as a credible event are not justified on a cost/benefit assessment. In these circumstances the protected events framework is rendered impractical and critical risks may remain unmitigated.

- Certain condition-dependent risks that could only previously be managed under the protected event framework can now be managed effectively under the indistinct events framework. The indistinct events framework allows AEMO to adjust the actions taken to manage an identified risk (to account for network changes or changes to the risk profile) promptly.

AEMO considers that the NER requirements for managing power system security for protected events mean that the framework may not be fit for purpose, in that it does not facilitate transparent and expedient implementation of efficient management measures targeted to minimise critical power system risks as they are identified.

To effectively support the energy transition, any risk management framework must allow for efficient and timely changes to be made in the face of rapidly changing system conditions and network configurations. An alternative to the current protected events framework could consider approaches that are less prescriptive, and do not necessarily require all aspects of power system security (other than the primary risk being managed) to be managed to the same limits as a credible continency event.

A simplified and less prescriptive framework could provide a pathway for AEMO to:

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

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

Recommendation 9

AEMO to review the protected event framework by Q4 2023. As part of this review, AEMO will consider the submission of a rule change proposal to enhance the protected event framework.

8 Recommendations and conclusions

8.1 Managing risks associated with Tamworth 330 kV bus fault and subsequent circuit breaker (CB) failure of bus coupler CB 5102 risk

As demonstrated in Section 5.1.2, a Tamworth 330 kV bus fault and subsequent CB failure of bus coupler CB 5102 can cause QNI to become unstable. This contingency has the potential to cause sustained power oscillations, or 132 kV network distance protection to operate, leading to separation of the Queensland region from the rest of the NEM. The failure/incorrect operation of CB 5102 is the key event of this incident (causing two busbars to trip and increasing the impact of this event). Therefore, any action that can be taken to ensure the correct operation of CB 5102 will reduce the likelihood of this incident occurring.

Transgrid has advised AEMO that CB 5102 was commissioned in 2002 and has a good condition history and that there are no population type issues identified for this CB family. Given CB 5102's good condition, AEMO recommends that Transgrid continues to maintain CB 5102 and associated equipment with consideration to the criticality and potential impact of its failure.

For the majority of the sensitivity studies completed, Queensland successfully formed an island following the trip of both 132 kV corridors. To ensure correct protection operation, AEMO recommends that Transgrid maintains the relevant 132 kV system distance protection systems and associated equipment with consideration to the criticality and potential impact of its failure.

In addition, AEMO identified that, under certain conditions, a CB 5102 failure and subsequent Tamworth busbar trip may not cause Queensland to separate from the NEM. If this sequence of events occurs, AEMO recommends that Transgrid System Operators open the 132 kV interconnections between Queensland and New South Wales manually.

AEMO is not recommending further action to mitigate this risk, as the future actionable ISP New England REZ 500 kV network augmentations (which have an optimal delivery date of July 2027) is expected to reduce the impact of this contingency as following fault clearance at Tamworth, Queensland will remain synchronously connected to the NEM via a new double-circuit 500 kV line from locality of Armidale South to Bayswater via east of Tamworth[136]. However, as part of the NSP planning obligations under NER S5.1.8, AEMO recommends that Transgrid confirms network stability will be maintained following the Tamworth contingency post the New England REZ 500 kV network augmentation.

Finally, as all recommendations to address this risk are zero-cost, no risk assessment or option filtering is required.

Further details on this recommendation can be found in Section 5.1.2.

[136] See https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en.

8.2 Managing risks associated with QNI instability

Detailed analysis by AEMO as part of the 2022 PSFRR and 2023 GPSRR has identified an existing and increasing risk of QNI instability following a range of non-credible contingencies across the mainland NEM, with the potential for subsequent power system events to occur[137]. These non-credible contingencies include:

- Loss of VNI (2022 PFSRR).
- Separation of South Australia through loss of Heywood – South East 275 kV lines (2022 PFSRR).
- South Australia separation at MLTS (2022 PFSRR and 2023 GPSRR).
- Loss of Columboola – Western Downs 275 kV lines resulting in large loss of load (2022 PFSRR).
- Loss of both 275 kV lines between Calvale and Halys with upgraded CQ and SQ SPS (2022 PSFRR).
- Fault on Loy Yang B unit 2 transformer with No. 3 500 kV bus CB failure (2023 GPSRR).
- Large amount of generation and DPV loss in Southern Queensland (2023 GPSRR).

Studies undertaken by AEMO show that an SPS that trips load in New South Wales and Queensland would be effective at preventing QNI from losing stability and Queensland separating from the rest of the mainland NEM.

AEMO recommends that Powerlink and Transgrid investigate, design and implement an appropriate SPS under NER S5.1.8 to mitigate this risk. If a scheme is found viable, AEMO recommends this scheme be commissioned as soon as possible, and no later than June 2025.

It should be ensured that any future QNI SPS operates effectively in conjunction with the SAIT RAS as well as existing NEM system protection and generation tripping schemes.

Further details on this recommendation can be found in Section 5.2.

8.3 Managing risks associated with SAIT RAS and QNI instability

Consistent with what was observed in the 2022 PSFRR, studies by AEMO highlight that for scenarios where loss of the MLTS lines could result in the SAIT RAS actions not being able to prevent a large power swing on PEC, this could lead to the tripping of PEC and the synchronous separation of South Australia, as well as the tripping of QNI and the synchronous separation of Queensland. Therefore, the results show that Moorabool separation can possibly cause loss of stability on QNI, which could be exacerbated by the actions of existing SPSs within Victoria and the SAIT RAS due to the total generation disconnected.

Given the potential for Moorabool contingency events to result in separation of the mainland NEM into four islanded areas – Queensland, South Australia separated at Heywood following EAPT operation, area between Heywood and Moorabool (not a viable island) and the rest of New South Wales and Victoria – AEMO recommends that AEMO, AVP, ElectraNet and Transgrid should continue collaborating as part of the PEC System Integration Steering Committee (SISC) to ensure that the SAIT RAS operates effectively in conjunction with existing NEM system protection and generation tripping schemes (see Appendix A3.2 for relevant schemes), as well as any future QNI SPS and other protection schemes.

[137] By inference, as observed during actual power system events.

Additionally, as full details of the SAIT RAS and any residual risks become available, AEMO will consider whether a Protected Event (or jurisdictional dispensation) is required to mitigate any identified residual risks.

Further details on this recommendation can be found in Section 5.2.

8.4 Contingency plans for emergency generation reserves and services

AEMO recommends that each participating jurisdiction develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risks. These plans should be for an appropriate level of capacity for the region, and encompass details of the generation technology, connection point and connection arrangement, fuel supply adequacy, environmental considerations, construction and commissioning timelines as well as equipment availability and lead times.

In addition to consideration of provision of capacity, it is recommended that jurisdictions consider potential opportunities to ensure availability of services such as those relating to system strength and voltage control. Retiral of existing coal and gas plant, and potential lead times to replace services with other equipment such as synchronous condensers and grid forming inverters may result in a deficit of available services for N-1 security and power system resilience.

It is therefore recommended that jurisdictions explore potential options to procure additional services, including conversion of existing facilities to synchronous condenser operation, which is covered by Engineering Framework FY23 priority Action A23: Achieve optimal deployment of synchronous condenser capability in new and existing synchronous generators[138].

Further details on this recommendation can be found in Section 6.5.

8.5 Managing risks associated with future operational capability

To prepare for the increasing operational demands required by the future power system, AEMO developed the OTR to review and uplift its operational capability. Similarly, Transgrid conducted a review on its operational capability and showed that the growth in complexity of the New South Wales power system could result in a 570% increase in risk of unserved energy due to system security incidents. With sufficient investment, Transgrid found it could mitigate up to 60% of this risk and deliver net benefits of $863.3 million over 10 years[139].

The issues identified by AEMO and Transgrid may be experienced by all NSPs, and it is important that these risks are understood and mitigated appropriately. In the context of the transforming power system and changing risk profile of the NEM, AEMO recommends that all NSPs, where not already doing so, undertake a formal review of their operating capability to understand evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training.

Further details on this recommendation can be found in Section 6.6.

[138] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2022/nem-engineering-framework-priority-actions.pdf?la=en&hash=F5297316185EDBD4390CDE4AE64F48BB.

[139] As per Transgrid's submission to GPSRR approach paper consultation, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/general-power-system-risk-review-approach-consultation/transgrid.pdf?la=en.

8.6 Managing risks associated with upcoming network augmentations

There are a number of major network augmentations identified in the ISP with actionable status. These projects have the potential to significantly change the power system's overall risk profile and many of these projects currently have planned commissioning dates within the next 10 years. Without suitable risk mitigations, non-credible contingency events impacting the equipment introduced by these major augmentations is expected to have a significant impact on the power system, such as:

- Potential to increase maximum contingency sizes from non-credible and credible contingencies.
- Increased system complexity and potential for control system/SPS interactions.
- Increased potential for key non-credible contingencies to cause cascading outages, widespread system instability and potential system black outs.

AEMO recommends that, in line with the requirements of NER S5.1.8, NSPs continue to consider non-credible contingency events which could adversely impact the stability of the power system. In considering these non-credible contingency events, NSPs should identify and implement suitable controls to mitigate any identified risks. It is anticipated that these controls may involve the implementation of new remedial action schemes, in which case NSPs should consult with AEMO and refer to the RAS Guidelines developed by AEMO and NSPs[140].

Further details on this recommendation can be found in Section 6.9.6.

8.7 Managing risks associated with changing generation patterns

Following the retirement of Liddell Power Station and the potential closure of Eraring Power Station, it is expected that the 330 kV lines that supply Sydney, Newcastle and Wollongong will have increased utilisation (increasing the period of time that these lines are highly loaded. AEMO expects a non-credible contingency event (post power station retirement) affecting these 330 kV lines that occurs during high flow conditions could cause voltage collapse and/or cascading thermal overloads.

Transgrid plans to study these risks to confirm the expected timing, impact and whether it is economical to mitigate these risks. AEMO recommends that Transgrid complete its study on the risk and consequence of non-credible contingencies on the 330 kV lines supplying Sydney, Newcastle and Wollongong following potential Eraring Power Station closure. AEMO also recommends that Transgrid share its investigation findings with AEMO for consideration in future GPSRRs.

Further details on this recommendation can be found in Section 6.9.8.

8.8 AEMO to finalise development of generator over frequency protection co-ordination strategy

To improve the power system's response to over frequency events, AEMO is developing an updated strategy for the overall co-ordination of generator over frequency protection settings. The adopted approach has minimal associated cost as it will be implemented in the existing connection process under NER S5.2.5.8. The strategy

[140] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/publication-of-remedial-action-scheme-guidelines/further-information/remedial-action-scheme-guidelines-consultation.pdf.

involves AEMO requesting staggered over frequency protection settings for all new connections to the NEM[141] and can be implemented under existing NER frameworks[142].

AEMO plans to adopt its updated generator over frequency protection co-ordination strategy by Q3 2023.

Further details on this recommendation can be found in Section 6.1.

8.9 AEMO to review the protected event framework

AEMO considers that the NER requirements for managing power system security for protected events mean that the framework may not be fit for purpose, in that it does not facilitate transparent and expedient implementation of efficient management measures targeted to minimise critical power system risks as they are identified. To effectively support the energy transition, any risk management framework must allow for efficient and timely changes to be made in the face of rapidly changing system conditions and network configurations. An alternative to the current protected events framework could consider approaches that are less prescriptive, and do not necessarily require all aspects of power system security (other than the primary risk being managed) to be managed to the same limits as a credible continency event. A simplified and less prescriptive framework could provide a pathway for AEMO to:

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

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

Accordingly, AEMO will review the protected event framework by Q4 2023. As part of this review, AEMO will consider the submission of a rule change proposal to enhance the protected event framework.

Further details on this recommendation can be found in Section 7.4.

[141] AEMO expects generators will be able to achieve these staggered protection settings without the need for any additional protection systems, with protection settings being outlined in each generator’s GPS and being applied in line with existing processes.

[142] Under NER S5.2.5.8, AEMO can nominate a frequency (above the upper limit of the operational frequency tolerance band) and associated time delay after which a generator must automatically reduce its output by at least half within 3 seconds, or disconnect within 1 second.